1710 Sixth Avenue North • P.O. Box 306 (35201) • Birmingham, AL 35203-2015 www.balch.com

BALCH
& BINGHAM LLP

Andrew W. Tunnell
t: (205) 226-3439
f: (205) 488-5858
e: atunnell@balch.com

February 8, 2013

BY ELECTRONIC FILING
Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Southern Companies' Order No. 1000 Regional Compliance Filing
Docket No. ER13-___-000
FILING SUBMITTED UNDER PROTEST

Dear Ms. Bose:

Southern Company Services, Inc., acting as agent for Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company (collectively "Southern Companies"), hereby provides, under protest, Southern Companies' compliance filing to the regional transmission planning and cost allocation requirements of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Order No. 1000.[1] This filing is also being made pursuant to the Commission's Order dated September 6, 2012, extending the pertinent filing deadline[2] and is being made electronically in accordance with the Commission's requirements. This filing provides revised tariff records for Attachment K (including Exhibit K-3) of Southern Companies' Open Access Transmission Tariff ("OATT"), which is located within Alabama Power Company's tariff designated as:

Tariff Title (Tariff Database) – OATT and Associated Service Agreements

Tariff Volume No. 5, Southern Companies OATT

[1] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 (2011), *order on reh'g and clarification*, 139 FERC ¶ 61,132 (2012) ("Order No. 1000-A"), *order on reh'g and clarification*, 141 FERC ¶ 61,044 (2012) ("Order No. 1000-B") (Order Nos. 1000, 1000-A, and 1000-B collectively referred to as "Order No. 1000," "Order," or "Final Rule").
[2] Letter Order, 140 FERC ¶ 61,185 (2012).

As discussed further below, Southern Companies participate in the Southeastern Regional Transmission Planning Process ("SERTP"), which has been codified in Attachment K to Southern Companies' OATT ("Attachment K") and has been accepted as compliant with the Commission's transmission planning requirements adopted in Order No. 890.[3] As reported to the Commission in several filings,[4] the SERTP has recently been expanded to include several additional transmission providers and owners, making the SERTP the largest Attachment K transmission planning region in the Eastern Interconnection in terms of transmission miles. In developing these proposals, this filing reflects the consensus of the expanded SERTP Sponsors as well as input from regulators and stakeholders. In accordance with this consensus, the other public utility transmission providers sponsoring the SERTP – (i) Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "LG&E/KU") and (ii) Ohio Valley Electric Corporation, including its wholly owned subsidiary Indiana-Kentucky Electric Corporation ("OVEC")[5] – are also filing contemporaneously herewith to adopt the SERTP as their transmission planning region for purposes of the Commission's Order No. 1000 regional transmission planning and cost allocation requirements. Furthermore, the nonjurisdictional transmission provider and owner Sponsors of the SERTP[6] have authorized Southern Companies to inform the Commission that they support this compliance filing.

Importantly, Southern Companies are making this filing provisionally and under protest in consideration of Southern Companies' request for rehearing[7] of Order No. 1000 and Petition for Review of the Order, which is pending before the United States Court of Appeals for the District of Columbia Circuit and consolidated with other appeals of the Order.[8] As such, the amendments being adopted hereto to comply with the regional requirements of Order No. 1000 are provisional and subject to the resolution of the pending appeals. By making this filing, Southern Companies are not waiving any of their challenges made to Order No. 1000. In addition, Southern Companies include with this filing an initial challenge to the application to them of Order No. 1000's regional compliance requirements.[9]

---

[3] *See Order on Compliance Filing*, 124 FERC ¶ 61,265 (2008); *Order on Rehearing and Compliance*, 127 FERC ¶ 61,282 (2009); *Order on Rehearing and Compliance*, 132 FERC ¶ 61,091 (2010).

[4] *See, e.g.*, *Status Reports of Kentucky Utilities Company, Louisville Gas and Electric Company, Ohio Valley Electric Corporation, and Southern Company Services, Inc.*, Docket No. RM10-23, filed November 2, 2012 and January 8, 2013.

[5] LG&E/KU, OVEC, and Southern Companies are collectively referred herein as the "Jurisdictional Sponsors."

[6] The nonjurisdictional utility Sponsors in the SERTP are: Associated Electric Cooperative Inc. ("AECI"), Dalton Utilities ("Dalton"), Georgia Transmission Corporation ("GTC"), the Municipal Electric Authority of Georgia ("MEAG"), PowerSouth Energy Cooperative ("PowerSouth"), the South Mississippi Electric Power Association ("SMEPA"), and the Tennessee Valley Authority ("TVA") (collectively, "the Nonjurisdictional Sponsors"). The Jurisdictional Sponsors and Nonjurisdictional Sponsors are collectively referred herein as the "SERTP Sponsors."

[7] *See Request for Rehearing of Southern Company Services, Inc.*, Docket No. RM10-23, filed August 22, 2011.

[8] *See South Carolina Public Service Authority v. Federal Energy Regulatory Commission*, Consolidated Case Nos. 12-1232, 12-1233, 12-1250, 12-1276, 12-1279, 12-1280, 12-1290, 12-1292, 12-1293, 12-1294, 12-1296, 12-1299, 12-1300, 12-1304, *et al.*

[9] This challenge is included as Exhibit B to this filing. Furthermore, by making this filing, Southern Companies are not waiving any rights that they may have, including those associated with the provisions of FPA Sections 210 and 211, regarding whether to interconnect with another utility, and with the prohibitions in FPA Sections 202(a)-(b) concerning involuntary transmission coordination and interconnections.

I. The SERTP is an Appropriate Regional Transmission Planning Process for Purposes of Order No. 1000

A. Overview: The SERTP Satisfies Order No. 1000's Regional Transmission Planning Process Requirements

Order No. 1000 directs public utility transmission providers to participate in a regional transmission planning process that produces a regional transmission plan[10] and that complies with seven (7) of Order No. 890's planning principles.[11] Order No. 1000 also requires regional planning processes to evaluate transmission alternatives that may address and resolve the transmission planning regions' needs more efficiently or cost-effectively than alternatives identified by individual public utility providers in their respective local processes.[12] As discussed herein, Southern Companies will continue to use the SERTP as their regional planning process. The SERTP has been found to comply with the referenced Order No. 890 planning principles and has provided for the identification of cost-effective solutions and extensive coordination by the transmission providers in the Southeastern sub-region of the SERC Reliability Corporation ("SERC") – an integrated footprint as large, or larger, than several ISOs/RTOs. Also, as discussed below, the SERTP is being hereby expanded to be the largest regional transmission planning process in the Eastern Interconnection (in terms of transmission miles), thereby providing for even further regional coordination among the expanded group of transmission providers and owners effectuated by the increased scope of the SERTP. In addition to this increased scope and coordination, the SERTP's existing coordinated, open, and transparent processes are being expanded as discussed herein to encompass their proposals to comply with Order No. 1000's regional transmission planning and cost allocation requirements. This combination will ensure that regional transmission projects will be considered for inclusion in the regional plan for regional cost allocation purposes ("RCAP") in a fair, nondiscriminatory, coordinated, open, and transparent manner.[13]

B. Expansion of the SERTP

By way of background, the SERTP was originally formed in 2006 by the transmission providers and owners in the Southeastern subregion of SERC, covering most of Alabama and Georgia, the panhandle region of Florida, and significant portions of Mississippi. These original sponsors of the SERTP are: Dalton Utilities, GTC, MEAG, PowerSouth, SMEPA, and Southern Companies ("Original SERTP Sponsors"). While the SERTP was formed as an open, transparent, and coordinated regional transmission planning process prior to the issuance of Order No. 890, the SERTP is the regional planning process that Southern Companies use to satisfy the transmission planning requirements adopted in Order No. 890, and was ultimately

[10] Order No. 1000, P 146.
[11] *Id.*, P 151 ("Specifically, the requirements of this Final Rule build on the following transmission planning principles that [the Commission] required in Order No. 890: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning.").
[12] Order No. 1000, P 148.
[13] The SERTP is also being specifically revised to provide for the annual preparation of a regional transmission plan, in accordance with Order No. 1000.

found by the Commission to satisfy the requirements of Order No. 890's nine (9) transmission planning principles.[14]

Following the issuance of Order No. 1000, Southern Companies were approached in June 2012 concerning possibly expanding the SERTP to include AECI, LG&E/KU, OVEC, and TVA. To allow the parties sufficient time to pursue the expansion of the SERTP and to allow for appropriate interactions with, and feedback from, regulators and stakeholders, the Commission granted the Jurisdictional Sponsors' request to provide them an extension of time – until February 8, 2013 – to comply with Order No. 1000's regional requirements.[15]

Southern Companies are pleased to announce a continued commitment to the expansion of the SERTP.[16] While this expansion was not required by Order No. 1000, the revised SERTP reflects the consensus of the expanded SERTP group, and the expansion necessitates some of the changes that are hereby being made to Southern Companies' Attachment K. The expanded SERTP essentially integrates into a single unified transmission planning region the regional planning performed for the following transmission systems: the original SERTP covering the transmission planning performed for the transmission systems in the Southeastern sub-region of SERC (*i.e.*, most of Alabama and Georgia and significant parts of Florida and Mississippi); LG&E/KU's transmission system, covering most of Kentucky and parts of Virginia; OVEC's transmission system covering parts of Indiana, Kentucky and Ohio; and the bulk of the Central Public Power Partners' ("CPPP") systems. The CPPP was formed by TVA, East Kentucky Power Cooperative ("EKPC"),[17] and AECI.[18] The CPPP is expansive, comprising parts of Alabama, Georgia, Iowa, Kentucky, Missouri, Mississippi, Oklahoma, and Tennessee. With this expansion, and as shown on the map provided as Exhibit A to this filing, the SERTP now includes all of Alabama and Georgia; most of Tennessee, Kentucky and Missouri; much of Mississippi; and portions of Florida, Indiana, Iowa, Ohio, Oklahoma, and Virginia. Based upon 2010 data, the expanded SERTP region has a total peak demand of approximately 96,000 MWs and approximately 66,000 circuit miles of existing transmission.[19]

C. The SERTP is an Appropriate Transmission Planning Region for Purposes of Order No. 1000

Order No. 1000 clarified that a transmission planning region is "one in which public utility transmission providers, in consultation with stakeholders and affected States, have agreed

[14] *See Order on Compliance Filing*, 124 FERC ¶ 61,265 (2008); *Order on Rehearing and Compliance*, 127 FERC ¶ 61,282 (2009); *Order on Rehearing and Compliance*, 132 FERC ¶ 61,091 (2010).
[15] *See Letter Order Granting Extension of Time*, 140 FERC ¶ 61,185 (2012).
[16] SMEPA has announced that it will be joining MISO. However, it has indicated that it intends to remain a Sponsor of the SERTP for at least a transitional period.
[17] EKPC has since requested membership in PJM.
[18] The CPPP was formed, at least in part, for reciprocity-related purposes pertaining to Order No. 890's transmission planning provisions.
[19] The expanded SERTP would be larger than MISO and PJM in terms of transmission mileage and compare well to MISO in terms of load. *See NERC 2011 Long-Term Reliability Assessment*, pp. 34 and 46 (providing that MISO has a peak of 98,068 MW with 50,144 circuit miles of transmission while PJM has a peak of 148,941 MW with 53,079 circuit miles).

to participate in for purposes of regional transmission planning and development of a single regional transmission plan."[20] Order No. 1000 explained that the Commission would not prescribe the geographic scope of any planning region but the existing Order No. 890 planning regions "should provide some guidance . . . in formulating planning regions."[21] The Commission clarified that an individual public utility transmission provider cannot, by itself, constitute a planning region and reaffirmed the criteria established in Order No. 890 that "the scope of a transmission planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions."[22]

As explained above, the SERTP was the Order No. 890 regional planning process used by Southern Companies to satisfy that order's requirements. Southern Companies respectfully submit that the original scope of the SERTP used to satisfy Order No. 890 would, by itself, be sufficient to satisfy Order No. 1000's scope of the region requirements. As explained in Southern Companies' transmittal letter for its original filing of its Attachment K, the Original SERTP Sponsors "own over 35,000 miles of transmission lines and constitute all of the NERC-registered transmission providers within the Southeastern subregion of SERC, collectively providing transmission service over an integrated footprint covering approximately 120,000 square miles of service territory."[23] Southern Companies further explained in a later filing in that proceeding:

> [T]he Southeastern Regional Transmission Planning Process builds upon the Annual Transmission Planning Summit process the Attachment K Sponsors commenced in 2006. Importantly, the Annual Transmission Planning Summit Process in turn builds upon existing transmission planning processes performed by the Attachment K Sponsors, as evidenced by the fact the Attachment K Sponsors consist of all of the transmission providers in the Southeastern Sub-Region of SERC. Given the highly integrated nature of the Attachment K Sponsors' systems and their historical planning practices, as well as the expansive size of their collective footprint, Southern Companies respectfully submit that the Southeastern Regional Transmission Planning Process constitutes an appropriately sized 'region' for purposes of Order No. 890.[24]

While the original scope of the SERTP would continue to constitute a valid, integrated region for purposes of Order No. 1000, the expanded SERTP clearly satisfies the regional scope requirements. As discussed previously, the expanded SERTP essentially combines the regional planning performed by the former SERTP, CPPP, LG&E/KU, and OVEC transmission processes/systems, thereby combining several contiguous planning regions and adjacent

[20] Order No. 1000, P 160.
[21] *Id.*
[22] *Id.*
[23] Southern Companies Attachment K Compliance Filing, Docket No. OA08-37-000, pp. 3 (December 7, 2007).
[24] Answer of Southern Company Services, Inc., Docket No. No. OA08-37-000, p. 9 (filed Jan. 22, 2008) (internal citation omitted) (footnote omitted).

balancing authority areas around the centrally located TVA. The SERTP Sponsors' respective electric systems are electrically integrated, with (among other things) numerous resource/power sale and purchase arrangements between them. Further reinforcing the integrated nature of the SERTP is the SERTP Sponsors' collective history and current practice of engaging in reliability coordination and transmission planning under the auspices of SERC. All but one of the SERTP Sponsors is a member of SERC, with the SERC members participating in SERC's reliability, adequacy, and critical infrastructure activities, as well as the transmission planning committee structure that SERC provides.[25]

D. The Use of the Existing SERTP to Satisfy Order No. 890's Seven (7) Planning Principles that Apply to Regional Processes and Overview of the Structure of Southern Companies' Attachment K

Order No. 1000 clarified that the following seven (7) regional planning principles from Order No. 890 will continue to apply to regional transmission planning processes: coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies.[26] In accordance with the expansion of the SERTP region, the provisions from the existing SERTP regional planning process that have been found by the Commission to satisfy Order No. 890 will continue to be utilized. Those existing provisions are codified as Sections 1-5 and 7 in Southern Companies' Attachment K. In keeping with the Commission's decision to build upon Order No. 890,[27] this approach means that the nonincumbent transmission developer, cost allocation, and other new elements being proposed by the SERTP to comply with Order No. 1000 will be incorporated into the existing SERTP planning processes that the Commission has already found to be open, transparent, coordinated and otherwise Order No. 890-compliant.[28] In filings being made contemporaneously hereto, LG&E/KU and OVEC are both adopting these same, Commission-accepted provisions (with only a few minor but necessary modifications reflecting their unique circumstances) to satisfy Order No. 1000's requirement that seven (7) of Order No. 890's planning principles will continue to apply to regional transmission planning processes. Accordingly, Southern Companies are not proposing changes to those existing Sections of their Attachment K except as necessary to comply with a specific requirement of Order No. 1000 or as necessary to accommodate the expansion of the SERTP (or to make a few minor formatting changes or to address typographical errors).[29] The few changes made to those Sections are discussed below at pp. 11-12.

---

[25] OVEC is currently a member of ReliabilityFirst Corp. ("RFC"), but is integrated with the other SERTP Sponsors – having (among other things) a 345 kV interface with the LG&E/KU system and a FERC-approved long-term power sale arrangement with LG&E for a portion of its total generating output. In addition, OVEC has begun an internal review of the possibility of moving from the RFC region to SERC, although any decision would be independent of SERTP participation.

[26] Order No. 1000, P 151.

[27] *See e.g.*, Order No. 1000, PP 316 and 328.

[28] *See Order on Compliance Filing*, 124 FERC ¶ 61,265 (2008); *Order on Rehearing and Compliance*, 127 FERC ¶ 61,282 (2009); *Order on Rehearing and Compliance*, 132 FERC ¶ 61,091 (2010).

[29] The decision to adopt the existing SERTP provisions that satisfy those seven (7) regional planning principles from Order No. 890 means that the other two Jurisdictional Sponsors (*i.e.*, LGE/KU and OVEC) are, contemporaneously to this filing, adopting those provisions into their respective Attachment Ks.

II. Stakeholder Process and Interactions with Regulators

The proposed Attachment K provisions being filed today represent not only the collective efforts and consensus of the SERTP Sponsors but also reflect extensive collaborative efforts with stakeholders and regulators. With regard to stakeholder dynamics, it bears emphasizing that there are important distinctions between the SERTP and the regional planning processes adopted by many Regional Transmission Organizations ("RTOs"). While RTOs typically do not own transmission or generation assets but provide services to transmission owners,[30] almost all of the SERTP Sponsors remain vertically integrated in nature, as they provide (either directly by themselves or through distributors or affiliated companies) electric service to the majority of the load within the SERTP's expansive footprint.[31] Accordingly, the SERTP is not only sponsored by the transmission providers and owners that provide service within the expanded SERTP, but is also sponsored by the majority of load serving entities within this area. Moreover, this vertically-integrated nature also means that for the two Jurisdictional Sponsors having significant retail load-serving responsibilities (*i.e.*, LG&E/KU and Southern Companies), the primary means by which their state commissions influence transmission-related decisions and activities is through their regulation of bundled retail service. The combined effect of the foregoing is that the SERTP process is supported by virtually all of the transmission providers and owners within this region and by the majority of load serving entities within this region. [32]

In addition to being inherently supported by virtually all of the transmission providers, transmission owners, and load serving entities within this region, the SERTP also reflects a collaborative process with stakeholders and regulators. The SERTP Sponsors have engaged in significant outreach efforts with stakeholders. The SERTP Sponsors' Order No. 1000 compliance materials and related issues have been vetted during the course of their four annual stakeholder meetings that occur during each transmission planning cycle beginning with the 2011 Annual Transmission Summit that occurred on December 14, 2011.[33] In addition to those discussions, the SERTP Sponsors have also conducted three interim meetings with stakeholders to specifically address Order No. 1000 issues. The SERTP Sponsors posted on their regional website iterations of their "strawman" compliance materials on March 14, 2012 and May 17, 2012, a related presentation for stakeholder and regulator review on October 10, 2012, and posted draft OATT language on two occasions (December 5, 2012 and January 14, 2013). Information regarding these activities, including meeting notes generally summarizing the

---

[30] RTOs typically provide transmission planning and OATT administration services and, in some cases, operate day-ahead and real-time markets.

[31] While the SERTP Sponsors (either directly or indirectly) constitute the majority of the load-serving entities within their collective footprint, it bears noting that the SERTP has substantial participation by certain, significant transmission dependent utilities. In particular, the Alabama Municipal Electric Authority is located within Southern Companies' footprint, and the Owensboro Municipal Utilities is located within LG&E/KU's footprint.

[32] In the Order No. 1000 compliance process, only a couple of entities – LS Power and a combination of environmentalist groups – were particularly active in providing feedback to the SERTP Sponsors. The environmentalist commenters were: Southern Environmental Law Center, Southern Alliance for Clean Energy, The Sierra Club, and The Sustainable FERC Project (NRDC).

[33] As noted above, Southern Companies were approached in June 2012 concerning expanding the SERTP; thus, AECI, LG&E/KU, OVEC, and TVA have been involved in Order No. 1000 compliance discussions with the SERTP since that time.

discussions at those meetings as well as the strawman proposals, presentations, draft Attachment K language, and stakeholder comments are found on the SERTP website.[34] The SERTP website is accessible via link from Southern Companies' OASIS webpage.

The SERTP Sponsors have also engaged in various outreach efforts and discussions with their State Commissions concerning the SERTP expansion and these Order No. 1000 proposals. The SERTP Sponsors have also actively sought feedback from the Commission's Staff. In addition to Commission Staff actively participating in the SERTP's different stakeholder meetings, the SERTP Sponsors have engaged in various other meetings and discussions with Commission Staff regarding the SERTP Sponsors' proposals.

The proposed Attachment K provisions being filed today contain changes and revisions reflecting certain feedback from stakeholders and regulators. For example, the transmission developer qualification and technical criteria being proposed were formulated in significant part based upon specific stakeholder feedback. Among other things, the requirement being proposed at Section 13.1.2(2) that the developer must have the "capability to finance U.S. energy projects equal to or greater than the cost of the proposed transmission project"[35] was based upon specific stakeholder feedback, as was an adjustment to the baseline-credit rating requirement in Section 13.1.2(1) so as to allow a parent company's credit rating (with guaranty) to meet the credit rating threshold. Similarly with regard to the technical qualification criteria, those requirements were revised based upon stakeholder feedback to allow considerations of the transmission developer's "parent company, affiliate or other experience"[36] to satisfy the requirement that the developer have the demonstrated capability to actually construct, own and operate the project(s). In addition, the proposal of an administrative fee in the amount of $25,000[37] was adopted based upon stakeholder input. Furthermore, to address a stakeholder concern that a developer might make such a payment and then early in the process either find out that its proposal is not viable or voluntarily withdraw its proposal, the proposed Attachment K provides for a $15,000 refund for early exits.[38] Several changes were also made to the RCAP evaluation process based upon stakeholder feedback. For example, in the initial benefit-to-cost analysis that has been proposed, the transmission provider will develop the planning level cost estimates for both the transmission developer's proposed project(s) and the transmission projects that would be displaced[39] to address the stakeholder concern that such an evaluation should use the same cost basis so as to be an "apples-to-apples" comparison.[40]

Several changes are also being proposed based upon Commission Staff feedback. For example, in response to Staff comments seeking more flexibility in the SERTP Sponsors' proposed criteria for what constitutes a "regional transmission facility" (*e.g.*, rated 300 kV or

---

[34] *See, e.g.,* http://www.southeasternrtp.com/ *and* http://www.southeasternrtp.com/general_documents.asp.
[35] *See* Attachment K, Section 13.1.2(2).
[36] *See id.*, Section 13.1.3(a).
[37] *See id.*, Section 15.1(8).
[38] *See id.*
[39] *See id.*, Section 16.2.1(c).
[40] As an aside, and as previously indicated, such analysis will be performed and shared with stakeholders and regulators in accordance with Attachment K's existing coordinated, open, transparent, and Order No. 890-complaint provisions, thereby ensuring a fair evaluation.

higher and at least 100 miles in length), the SERTP Sponsors are proposing that other transmission projects not meeting the foregoing standard will still be considered on a case-by-case basis should they effectuate similar regional transfers and address similar regional needs.[41] Commission Staff also commented that certain steps specified in the SERTP Sponsor's initial proposal for a facility to be eligible for RCAP should not be required as prerequisites. Several revisions are being proposed based upon that feedback, including: eliminating a previously required step that a Memorandum of Understanding would have to be developed; eliminating a provision that a proposed transmission project might be included in the transmission plan "for informational purposes" while under consideration for RCAP; and modifying the requirement to have a contract in place before a transmission project is selected in the regional plan for RCAP.

III. The Revisions to Southern Companies' Attachment K Made to Comply with the Regional Requirements of Order No. 1000

A. Overview of the Structure of Southern Companies' Revised Attachment K and Explanation of how the SERTP Satisfies the Commission's Local and Regional Transmission Planning Requirements for Southern Companies

The organizational structure of Southern Companies' Attachment K being filed today is driven, in substantial part, by the decision to continue to use the provisions from Southern Companies' existing Attachment K to satisfy the seven Order No. 890 planning principles that will continue to apply to regional processes. As previously discussed, Order No. 1000 does not require transmission providers to begin from scratch in developing their Order No. 1000 compliance processes, but instead clarified that the Commission is building upon Order No. 890.[42] Therefore, the Jurisdictional Sponsors' collective proposals that are being filed today to satisfy, for example, Order No. 1000's public policy, enrollment, and regional cost allocation requirements are all being proposed in conjunction with Southern Companies' existing, Commission-accepted Attachment K provisions providing for a coordinated, open and transparent transmission planning process.[43] The foregoing means, for example, that transmission project proposals, analysis, and decisions made in accordance with the new Attachment K Sections (*i.e.*, Sections 10-21) will be shared for stakeholder feedback in accordance with those existing, provisions providing for a coordinated, open and transparent transmission planning process (*i.e.*, Sections 1-5 and 7).

In addition to building upon Southern Companies' existing Attachment K provisions, another element affecting the organizational structure of Southern Companies' revised Attachment K is Order No. 1000's apparent requirement that tariff language be included in the filing outlining the transmission provider's "local transmission planning process." In this regard, the *pro forma* OATT contained as appendices to both Order Nos. 1000 and 1000-A provides such tariff language.[44] For Order No. 890 planning purposes, Southern Companies satisfied

---

[41] *See* Attachment K, Section 14(1).
[42] *See, e.g.*, Order No. 1000-A, PP 102, 103, and 170.
[43] *See* Attachment K, Sections 1-5 and 7.
[44] *See* Order No. 1000, Appendix C: *Pro Forma* Open Access Transmission Tariff; Order No. 1000-A, Appendix B: *Pro Forma* Open Access Transmission Tariff.

Order No. 890's planning requirements (both regional, and to the extent applicable, local requirements) through the SERTP by sharing, for stakeholder feedback, the transmission planning criteria, data inputs, base cases, and (thereby) all of the transmission projects that are to be included in a transmission expansion plan for a given planning cycle. Perhaps even more importantly, Southern Companies do not perform transmission planning for its native load and OATT customer requirements in isolation, which could be inferred from Order No. 1000's clarification that local planning is that performed for the needs of "the transmission provider and its Network and Point-to-Point Customers,"[45] with an underlying assumption possibly being that coordination with neighboring and affected transmission providers and owners only occurs subsequently at the regional or inter-regional levels. This is not the case for Southern Companies. Southern Companies' transmission planning for its native load and OATT-customers is thoroughly coordinated with affected transmission providers and owners, with (for example): Georgia Power Company having long-engaged in coordinated transmission planning for its proposed transmission upgrades with the other transmission providers and owners in Georgia (*i.e.*, Dalton Utilities, GTC, and MEAG); Alabama Power Company, Georgia Power Company, and Gulf Power Company having long-engaged in coordinated transmission planning with PowerSouth; Mississippi Power Company having long-engaged in coordinated transmission planning with SMEPA; and Southern Companies otherwise having engaged in coordinated transmission planning as necessary with other affected transmission systems.

Given the foregoing, Southern Companies propose to continue with their approach from Order No. 890 of using the SERTP to satisfy the Commission's local and regional transmission planning requirements. Southern Companies note that this approach is not only appropriate because it continues to allow, for example, stakeholders to provide feedback regarding all transmission upgrades being made by Southern Companies (and by the other SERTP Sponsors), but it is also more efficient in that it allows such review and feedback to occur in a single venue.

To codify the foregoing approaches to satisfy the Commission's transmission planning requirements, Southern Companies' revised Attachment K being adopted hereunder is organized as follows:

- <u>Preamble</u>: The introductory paragraph and footnote from Southern Companies' existing Attachment K have been largely retained.

- <u>Local Transmission Planning Overview</u>: An overview of Southern Companies' local transmission planning is provided at pages 2-3 of the clean version of the revised Attachment K that is being filed for posting in eLibrary. This overview language is largely taken from the *pro forma* language provided by the Commission at pages 587-89 of Order No. 1000-A. Among other things, these OATT pages cross-reference Sections 1-9 of Southern Companies' Attachment K that specifically comply with Order No. 890's transmission planning requirements.

[45] *See* Order No. 1000-A, Appendix B: *Pro Forma* Open Access Transmission Tariff.

- Regional Transmission Planning Overview: An overview of Southern Companies' regional transmission planning is provided at pages 4-6 of the clean version of the revised Attachment K that is being filed for posting in eLibrary. This overview language is largely taken from the *pro forma* language provided by the Commission at pages 589-91 of Order No. 1000-A. Among other things, these Attachment K Pages cross-reference: i) Sections 1-5 and 7 of Attachment K that specifically comply with the seven (7) Order No. 890 transmission planning principles that Order No. 1000 clarified will continue to apply to regional transmission planning processes[46] and ii) the new Sections 10-21 of Attachment K that are being proposed to comply with Order No. 1000's new regional transmission planning and cost allocation requirements.[47]

- Retention (with Slight Modification) of Southern Companies' Existing Attachment K Sections that Comply With Order No. 890: Following the above-discussed regional and local transmission planning overviews, Southern Companies' Attachment K then provides its Sections 1-9, which are their Commission-accepted provisions that comply with Order No. 890's transmission planning requirements.

- Addition of New Attachment K Sections to Address Order No. 1000's Regional Transmission Planning and Cost Allocation Requirements. The new Sections 10-21 of this Attachment K that are being filed to comply with Order No. 1000.

B. Revisions to Southern Companies' Existing, Order No. 890-Compliant Attachment K Provisions: Attachment K Sections 1-9

As discussed above, Southern Companies are only proposing changes to their existing Attachment K provisions (*i.e.*, Sections 1-9) that are necessary to comply with specific requirements of Order No. 1000 or are necessary to accommodate the expansion of the SERTP. In addition, a few minor formatting changes have been made (in an effort to reduce the length of Attachment K), and a few typographical errors have been addressed. These changes are shown in the redlined document included in this filing. Some of the more significant changes include the following:

- Changes Made to Comply with Order No. 1000's Requirement to Produce a Regional Plan: A few edits have been made to the existing Attachment K

[46] In accordance with Order No. 890, Southern Companies Attachment K does not have a separate section addressing that Order's comparability planning principle. Instead, Southern Companies commit to provide comparable and non-discriminatory service, with the commitment to comparability permeating the SERTP. *See* Order No. 890, P 494-95; Attachment K, n. 2 and 3.

[47] All three of the Jurisdictional Sponsors are (by separate filings being made today) essentially adopting the equivalent of Sections 1-5, 7, and 10-21 of Southern Companies' Attachment K that is being filed herein so as to use the SERTP to satisfy Order No. 1000's regional requirements.

provisions to comply with Order No. 1000's requirement that the regional planning processes produce a regional transmission plan.[48] In this regard, the SERTP has always provided for the coordinated, open, and transparent preparation of an annual transmission expansion plan, and Section 1.2.4.1 has been revised to provide that at the Annual Transmission Planning Summit and Assumptions Meeting, an overview of the regional transmission plan for Order No. 1000 purposes will be provided to stakeholders, which should include the ten (10) year transmission expansion plan. In addition, footnote 4 has been revised to explain that the discussions of plan, plans, and planning throughout the Attachment K may refer to the regional transmission plan required for Order No. 1000 purposes, as may be appropriate in any particular instance.

- Changes Made to Reflect the Expansion of the SERTP:

    - References to SERC Have Been Broadened: While the Original SERTP Sponsors were all members of SERC, one of the new SERTP Sponsors (*i.e.*, OVEC) is a member of the RFC. Since the existing Attachment K makes numerous references to SERC, those references, when made to one of the Sections applying to regional planning requirements, have been broadened to include SERC "or other applicable NERC region." Those types of changes are made at Sections 1.2.2, 1.2.3, 1.2.4, and 2.5.1.

    - Revisions to the Reliability Planning Process Discussion at Section 6.6 Due to the Expanded SERTP: With the expansion of the SERTP, it became apparent that the existing references in Section 6.6[49] to "Region" were no longer appropriate because those existing references assumed that the scope of the "region" was essentially the Southeastern Sub-Region of SERC/Southern Companies. With the region now also including AECI, LG&E/KU, OVEC, and TVA, those references are no longer accurate. Likewise, the existing references therein to "inter-regional" could essentially be construed now to be the expanded SERTP. Accordingly, those references to region and inter-region have been modified as appropriate for the context throughout Section 6.6.

- Other Revisions to the Existing Sections: The other revisions to these existing sections are largely minor in nature, including: footnotes identifying which Sections only apply to local transmission planning; edits to address typographical errors; and formatting changes made in an effort to reduce the length of Attachment K.

[48] *See* Order No. 1000, P 146.
[49] Section 6 provides Southern Companies' compliance to Order No. 890's regional participation principle. In accordance with Order No. 1000, this principle only applies to Southern Companies' local transmission planning. *See* Order No. 1000, P 151.

C. New Attachment K Sections Proposed to Comply with Order No. 1000

To comply with the bulk of Order No. 1000's regional transmission planning and cost allocation requirements, Southern Companies are hereby proposing to adopt new Sections 10-21 of their Attachment K, discussed below.

1. Public Policy: Section 10

Order No. 1000 requires transmission providers to amend their OATTs to provide for the consideration of transmission needs driven by public policy requirements.[50] In adopting these public policy procedures, Order No. 1000 requires that stakeholders be allowed an opportunity to provide input and offer proposals regarding the transmission needs they believe are driven by public policy requirements.[51] Southern Companies have addressed these requirements at Section 10 of their revised Attachment K. As discussed in Section 10.1, Southern Companies strive to address all public policy requirements in their routine transmission planning "through the planning for and provision of long-term firm transmission services to meet: i) native load obligations and ii) wholesale Transmission Customer obligations under the Tariff" consistent with all federal and state reliability and other requirements applicable to transmission. Furthermore, Section 10.2 allows stakeholders to propose transmission needs driven by public policy requirements for consideration, and Section 10.3 provides that if a transmission need is identified that is not already addressed in the transmission planning process, the transmission provider will identify a corresponding transmission solution. Section 10.4 also provides that a response to stakeholder input regarding transmission needs driven by public policy requirements will be posted on the regional website.[52]

2. Merchant Transmission Developers: Section 11

Order No. 1000-A clarified that, because a merchant developer's transmission facility can impact a region's transmission network, merchant transmission developers must provide adequate information and data to allow public utility transmission providers in the transmission planning region to assess the potential reliability and operational impacts of such proposed merchant transmission facilities on other systems in the region.[53] In accordance with that requirement, proposed Section 11 of Attachment K requires merchant transmission developers who propose to develop a transmission facility that will impact the transmission systems within the SERTP (including those who do not seek regional cost allocation under this Attachment K) to provide information and data necessary to assess the potential reliability and operational impacts of those facilities. Section 11 requires that data to include "[t]ransmisson project timing, scope, network terminations, load flow data, stability data, HVDC data (as applicable), and other technical data necessary to assess potential impacts."

---

[50] *See* Order No. 1000, P 203; Order No. 1000-A, P 317.
[51] Order No. 1000, P 207.
[52] *See* Order No. 1000-A, P 325.
[53] Order No. 1000-A, P 297.

3. Enrollment: Section 12

Section 12 has been added to Attachment K to comply with Order No. 1000-A's enrollment requirements. Since enrollment is driven by Order No. 1000's cost allocation requirements,[54] Section 12.1 provides that those utilities who could be the "beneficiaries" of a cost allocation determination made in accordance with this Attachment K are generally eligible to enroll. As this Attachment K adopts a quantifiable "avoided transmission costs" methodology[55] to determine whether a regional project seeking cost allocation is a more "efficient and cost effective" regional alternative, the utilities generally eligible to enroll are defined in Section 12.1 as "[a] public utility or non-public utility transmission provider and/or transmission owner having a statutory or tariff obligation to ensure that adequate transmission facilities exist within a portion of the SERTP." In addition to those who may enroll as provided in Section 12.1, Order No. 1000-A requires that entities seeking regional cost allocation must enroll if they or an affiliate have load within the region.[56] This requirement has been proposed at Section 12.2. In order to enroll, Section 12.3 provides that entities are to execute the enrollment application form posted on the SERTP website except that Southern Companies, who have adopted the SERTP in its OATT, will be deemed to have enrolled.[57] Order No. 1000-A also provides that there must be a clear withdrawal process for nonjurisdictional transmission providers to unenroll.[58] Section 12.6 provides that, in general, an enrollee may unenroll by providing written notice, with that withdrawal becoming effective at the end of the planning cycle, provided that the notification must be tendered at least sixty (60) days prior to the Annual Transmission Planning Summit and Assumption Input Meeting (which is held in the 4th quarter of each year).

Order No. 1000-A also provides that the different regions are to address the enrollment-related concerns raised by their non-public utility transmission providers.[59] In accordance with that guidance, Section 12.5 proposes provisions that seek to ensure that the nonjurisdictional entities understand exactly what they are committing to by enrolling. Specifically, Section 12.5 provide that a nonjurisdictional's enrollment is subject to the condition subsequent that if the Commission or other governmental entity requires changes to this Attachment K, then such enrollee may immediately withdraw. Importantly, should such an event occur, then an enrolled nonjurisdictional utility(ies) may immediately withdraw from the SERTP by providing written notice within 60 days of that order or action.

The list of enrollees will be posted and maintained on the SERTP website. As referenced above, the Jurisdictional Sponsors – LG&E/KU, OVEC, and Southern Companies – are deemed to have enrolled. While certain entities are continuing to consider enrollment, particularly pending review of the Commission's actions with regard to the Order No. 1000 compliance filings to be made by the Jurisdictional Sponsors, Southern Companies note that all of the

---

[54] *See* Order No. 1000-A, P 275.
[55] *See infra* at pp. 19-22 (discussing Attachment K, Section 17).
[56] Order No. 1000-A, P 417.
[57] LG&E/KU and OVEC are adopting similar provisions in their respective OATTs.
[58] Order No. 1000, P 622.
[59] *See* Order No. 1000-A, P 277.

Nonjurisdictional Sponsors have indicated that they intend to continue to participate in the SERTP's coordinated, open, and transparent regional transmission planning process.

4. Southern Companies Have No Federal Right-of-First-Refusal

One of the primary reasons that the Commission provides for adopting Order No. 1000 is to eliminate federal rights of first refusal ("ROFR") for incumbent utilities to construct the new transmission facilities necessary to serve their customers.[60] As explained in the Order No. 1000 rulemaking process, neither Southern Companies nor (to the best of their knowledge) any of the other SERTP Sponsors have any such federal ROFR that has to be so eliminated.

5. Transmission Developer Qualification Criteria to Propose Projects for Selection in the Regional Plan for Purposes of Cost Allocation: Section 13

Order No. 1000 requires all public utility transmission providers to adopt specific provisions allowing nonincumbent transmission developers to propose regional transmission projects that they may develop and to allocate their costs commensurate with benefits. One of these requirements is that the transmission provider must specify the qualification criteria for an entity to be eligible to propose a transmission project for selection in the regional plan for purposes of cost allocation, whether that entity is an incumbent or nonincumbent developer.[61] Section 13 has been proposed to comply with these requirements. As discussed above concerning stakeholder interactions, these qualification provisions, along with the criteria for a facility to be considered "regional" in Section 14 and the information requirements proposed in Section 15, were formulated with specific stakeholder and Commission Staff feedback.

With regard to qualification criteria, Section 13.1.2(1) requires that the developer or its parent company have a BBB- or Baa3 credit rating from the pertinent credit-rating agency. Importantly, this requirement is comparable, as all of the SERTP Sponsors satisfy at least this minimum standard. Moreover, since Order No. 1000 allows nonincumbent developers to essentially take the place of the incumbent service providers to develop the new transmission facilities necessary for the incumbent to render reliable and economic service, the nonincumbent must have at least this minimum level of ability to not only obtain financing, but also to render long-term service to meet the needs of the consuming public. While having this credit level is no guarantee, it is a prudent measure (and, hence, just and reasonable and non-discriminatory) to protect customers. This credit rating or equivalent surety of financial stability would be applied in a nondiscriminatory and nonpreferential manner to all entities, including any SERTP Sponsor, that propose projects for selection in the regional transmission plan for RCAP.

In addition to this credit rating requirement, Sections 13(2)-(3) also require the transmission developer to provide documentation of its financing and development capability, including a summary of its prior transmission development experience and history of any

---

[60] *See*, Order No. 1000, P 253, *et seq.*
[61] *E.g.*, Order No. 1000, P 323; Order No. 1000-A, P 439.

violations of NERC, Regional Entity, or other regulatory requirements pertaining to electric infrastructure development, construction, ownership, or operation and maintenance. In accordance with Order No. 1000, these informational requirements do not require the transmission developer to register with NERC,[62] but rather, only to inform the SERTP Sponsors if they have already done so.

6. Transmission Facilities Potentially Eligible for Selection in the Regional Plan for Purposes of Cost Allocation: Section 14

Order No. 1000 defines the regional transmission facilities subject to its requirements as those "located solely within a single transmission planning region and are determined to be a more efficient or cost-effective solution to a regional transmission need."[63] Order No. 1000 further clarifies,

> Such transmission facilities often will not comprise all of the transmission facilities in the regional transmission plan; rather, such transmission facilities may be a subset of the transmission facilities in the regional transmission plan. For example, such transmission facilities do not include a transmission facility in the regional transmission plan but that has not been selected in manner described above, such as a local transmission facility or a merchant transmission facility.[64]

Order No. 1000 provides other guidance relevant to the development of the criteria for what should constitute a regional transmission facility. In this regard, Order No. 1000 provides the regions flexibility in developing their regional cost allocation proposals to reflect regional differences.[65] Order No. 1000 also seeks to complement, not supplant, existing transmission planning activities "to ensure that public utility transmission providers in every transmission planning region, in consultation with stakeholders, evaluate proposed alternative solutions ***at the regional level*** that may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers."[66] Order No. 1000 also expresses the Commission's intent for Order No. 1000 to work together with the requirements of Order 890 and not "disrupt the progress being made with respect to transmission planning and investment in transmission infrastructure."[67]

The SERTP is a very large region in virtually all aspects: geographically, electrically, and in terms of customer loads, miles of transmission lines, generating resources, etc. Achieving

---

[62] *See* Order No. 1000-A, P 444.
[63] Order No. 1000, P 63.
[64] *Id.* Accordingly, a regional transmission facility subject to Order No. 1000's requirements is not any facility other than a "local facility" (as some have claimed), as Order No. 1000 clearly provides that local transmission facilities are just an "example" of a type of transmission facilities that are not subject to the requirements applicable to facilities selected in a regional plan for purposes of cost allocation.
[65] *See, e.g.,* Order No. 1000, PP 223 and 302.
[66] Order No. 1000 P 68 (emphasis added).
[67] Order No. 1000, P 31.

efficiencies at the regional level necessarily involves the large economies of scale of high voltage transmission lines capable of moving significant amounts of power reliably and economically over long distances. The transmission system of the SERTP Sponsors is built to integrate generation to large load centers utilizing major 300+ kV transmission lines. As demonstrated by the SERTP transmission map attached as Exhibit A to this filing, the "backbone" transmission facilities that convey bulk transfers throughout the expansive SERTP region are the long, 345 kV and 500 kV transmission lines that interlace the SERTP and interconnect the different balancing authority areas ("BAAs") in this region. These high voltage transmission facilities provide regional efficiencies through significant reliability, economic, and operational benefits. As shown on that map, these high voltage transmission facilities provide benefits across multiple jurisdictions, with the expanded SERTP encompassing a huge geographic area in twelve (12) different States. As also shown on the referenced map, the SERTP contains numerous transmission lines that satisfy this standard. While the next lower voltage (*i.e.*, 230 kV) classification of transmission facilities might convey "regional" deliveries for smaller regions, this is not the case in a region having the scale of the SERTP. The addition of lower voltage facilities, with their higher impendences and lower loadings, simply would not provide regional impacts. Moreover, 230 kV transmission facilities are becoming increasingly load-serving in nature for the SERTP utilities.

The SERTP process is structured to focus regional planning activities and resources on identifying project alternatives of a regional scale which may be more efficient and cost effective than the typically smaller, shorter-lead time transmission facilities identified through bottom-up planning processes. In addition, the SERTP process is structured in an effort to complement bottom-up planning activities by identifying efficient and cost effective alternatives of regional scale well in advance of regional needs, providing sufficient time to fully develop and construct such regional projects, and avoiding disruptions to the efficient and timely completion of the high volumes of upgrades identified on existing facilities and underlying systems through State IRP or other local load serving processes. Therefore, the transmission facilities in the SERTP that generally address "*regional* needs" are those rated 300 kV and above which transverse a regionally significant distance (*i.e.*, 100 miles or more) across two or more BAAs. These criteria for an SERTP regional transmission facility are described at Section 14(a)-(b) of Attachment K. Importantly, because the SERTP Sponsors continually strive to identify economic expansion options, and pursuant to recommendations from Commission Staff, while the foregoing establishes the general standard for an SERTP regional transmission facility, other transmission facilities capable of providing similar, significant bulk transfers and regional benefits will also be considered on a case-by-case basis in accordance with Section 14(1).

Other criteria proposed in Section 14 are requirements that the proposed regional transmission project may not be merely an upgrade to an existing facility, and may not use rights-of-way of parties other than the developer absent the consent of the owner of such rights-of-way. These provisions are aimed, among other things, to prevent the unnecessary disputes that would inevitably ensue should a developer attempt to use the right-of-way belonging to another without first obtaining that party's consent. Another element pertains to the requirement that the proposed transmission project must be materially different than those under consideration and those that have been previously considered in the expansion planning process.

This "materially different" requirement was adopted in accordance with Order No. 1000's fundamental holding that the regional transmission facilities are those that "are more efficient and cost effective solutions."[68] Transmission proposals that, for example, have already been considered do not offer new alternatives and requiring their consideration (again) would undermine the efficient planning and expansion of the transmission system.

Before leaving these criteria, it must be emphasized that the foregoing criteria are not only being proposed pursuant to Order No. 1000's holding that a regional transmission facility is one that addresses "a regional need," but are also important to retain the continued support of the Nonjurisdictional Sponsors to the SERTP process.[69]

7. Submission and Evaluation of Proposals for Potential Selection in a Regional Transmission Plan for Purposes of Regional Cost Allocation: Section 15

Order No. 1000 requires public utility transmission providers to revise their OATTs to identify: (a) the information that must be submitted to be considered in a given transmission planning cycle; and (b) the date by which such information must be provided to be considered in a given transmission planning cycle.[70] Order No. 1000 provides that these provisions could require, for example, relevant engineering studies and cost analyses, and may request other reports or information from the transmission developer necessary to evaluate the transmission project in the regional planning process.[71]

Sections 15 of Attachment K implements Order No. 1000's requirements pertaining to the information that must be submitted by a prospective transmission developer in support of a transmission project it proposes for potential selection in the regional transmission plan for RCAP,[72] and is structured to solicit project proposals at the beginning of each planning cycle. As discussed previously, these provisions were developed reflecting specific stakeholder and regulatory feedback. Some of the key aspects of these requirements include the provision of specified descriptive and technical information for the project, so that it can be assessed efficiently with other project alternatives without delays resulting from insufficient technical data. In addition, Section 15.1 requires the provision of a $25,000 administrative fee to cover the costs necessary to review, process, and evaluate the proposal. Should the developer elect to withdraw the project early in the evaluation process or should the developer be found to be noncompliant (and not remediated) early in the process, these provisions provide that $15,000 of that fee will be refunded. With regard to the submission deadline required by Order No. 1000,[73] Section 15.2 requires that in order for a project to be considered for potential selection in the regional plan for RCAP for a particular planning cycle, the proposal must be submitted no later

[68] *See, e.g.*, Order No. 1000 at PP 6 and 81 (stating an intent to require revisions to regional transmission planning process that may resolve needs "more efficiently and cost-effectively").
[69] *See e.g.,* Order No. 1000-A, P 277 (providing for regional flexibility to facilitate nonjurisdictional participation).
[70] Order No. 1000, P 325.
[71] *Id.*, P 326.
[72] *Id.*
[73] *Id.*, P 325.

than 60 calendar days after the previous planning cycle's SERTP Annual Transmission Planning Summit and Input Assumptions Meeting. This requirement, that proposals be provided at the beginning of the pertinent transmission cycle, enables transmission developers' projects to be evaluated comparably and efficiently under the same planning processes that assess the other transmission projects under consideration. Proposals can be submitted after that date at any time, but may be considered in subsequent cycles. To further encourage proposals and ensure accuracy in data, Section 15.3 also provides the transmission developer an opportunity to remedy any identified deficiencies in its qualification criteria or information supplied. Of course, once these qualification and data requirements are satisfied, it remains critical to the reliable and economic planning and expansion of the transmission system for the developer to *maintain* compliance so as to retain the viability to complete the project. Section 15.4, thus, requires the developer to maintain compliance with these qualification requirements.

8. Evaluation of Proposals for Selection in a Regional Plan for RCAP and the Adoption of an "Avoided Transmission Costs" Cost Allocation Methodology: Sections 16 and 17

Order No. 1000 requires each public utility transmission provider to amend its OATT to describe a transparent and not unduly discriminatory process for evaluating whether to select a transmission project proposal in the regional plan for purposes of cost allocation, requiring this process to comply with Order No. 890's transparency, openness, and coordination requirements.[74] "[F]or one solution to be chosen over another in the regional transmission planning process, there should be an evaluation of the relative efficiency and cost effectiveness of each solution."[75] Order No. 1000 further requires that nonincumbent transmission developers must have the same eligibility as an incumbent developer to use a regional cost allocation method for its proposed transmission projects that are selected in a regional plan for RCAP.[76] A mechanism also has to be established to ensure that all projects are eligible for consideration for selection in the regional plan for RCAP.[77] The Commission emphasized that it was allowing regional flexibility in developing the different approaches to these transmission planning evaluations.[78] In analyzing the cost estimates for different transmission projects, the Commission emphasized that "the regional planning process must scrutinize costs in the same manner whether the transmission project is sponsored by an incumbent or nonincumbent transmission developer."[79] With regard to cost allocation for selected projects, Order No. 1000 establishes six cost allocation principles that have to be satisfied.[80]

Section 16 implements these requirements and provides the mechanism for the potential selection of regional transmission projects in the regional plan for RCAP. Furthermore, Section

---

[74] *Id.*, P 328.
[75] *Id.*, n. 307.
[76] *Id.*, P 332.
[77] *Id.*, P 336.
[78] Order No. 1000-A, PP 453 and 455.
[79] *Id.*, P 455; *See also id.*, P 689 ("[W]e clarify that regional cost allocation method for one type of regional transmission facility or for all regional transmission facilities may include voting requirements for identified beneficiaries to vote on proposed transmission facilities.").
[80] *See*, Order No. 1000, P 603, *et seq*.

16 combined with Section 17 also satisfies Order No. 1000's cost allocation requirements. The evaluative and cost allocation methodology proposed by the SERTP Sponsors in these Sections is based upon the benefits received from the quantifiable "avoided transmission" costs of a proposal that is determined to be a more efficient and cost effective regional alternative than other projects under consideration. Stated differently, the benefits would be the displacement cost savings received by replacing the higher cost planned transmission project(s) with the more efficient and cost effective proposed project(s) that address long-term needs previously being addressed by the displaced projects. Southern Companies or other entities who have their transmission projects displaced by the proposed project, and thereby would receive costs savings, would be the beneficiaries themselves or on behalf of their customers.

As discussed below, this cost allocation methodology is appropriate, as it satisfies the Commission's regional cost allocation principles adopted in Order No. 1000, with this process providing a clear, *ex ante* method for determining costs and benefits. Because different transmission facilities can always be developed to meet any particular level of requirements for transmission reliability and delivery capacity, the benefit of any particular transmission facility or set of facilities can be quantified by comparing the costs of implementing different alternatives which could also meet the same requirements. For this reason, using this methodology provides a consistent, objective measure for comparing transmission alternatives and avoids dependencies on highly uncertain energy prices and other forward market assumptions.

To determine whether the proposed transmission project would be a more efficient and cost effective alternative, Section 16 provides for the performance of two benefit-to-cost analyses. The first would be an initial benefit-to-cost analysis using high-level transmission planning estimates that would compare the estimated costs of the proposed transmission project (plus the costs of additional facilities that might be necessary to integrate the proposed transmission project) to the costs of the planned transmission projects that would be displaced.[81] Planning level cost estimates would be used since it is unlikely that detailed, engineering level estimates would be available when a transmission project is initially proposed, although Section 16.2.1(c) provides that such detailed estimates may be used if available. To ensure a comparable cost comparison between the pertinent projects, the SERTP Sponsors would develop the planning level estimates. Assuming that the transmission project satisfies at least a 1.25 benefit-to-cost ratio using planning level estimates, then Section 16.3 provides for the performance of a detailed benefit-to-cost analysis to be performed after the detailed costs components of the proposed transmission project and affected projects are identified. Should the project pass at least a 1.25 benefit-to-cost ratio based upon that detailed analysis, then the project would be selected in the regional plan for RCAP if the project's detailed financial terms are acceptable to each beneficiary and approval is obtained from the pertinent jurisdictional authorities/governance boards. With regard to this requirement to obtain jurisdictional authority/governance approval, obtaining such consent is not only critical to the viability of the project to actually get constructed (since, for example, the States retain siting authority), but it is also consistent with the Commission's encouragement for Attachment K proposals to "establish a formal role for

[81] *See* Attachment K, Section 16.2.

state commissions in the regional transmission planning process"[82] and to facilitate the incumbent's ability to continue to comply with its duty to serve requirements. Likewise, the Nonjurisdictional Sponsors have emphasized the need to obtain their governance approvals so as to facilitate their ability to participate in the SERTP.[83]

Importantly, since the SERTP process is going to continue to apply Southern Companies' existing, Order No. 890 Attachment K regional provisions, these benefit-to-cost evaluations will be performed through the SERTP's existing, coordinated, open, and transparent processes. Furthermore, as both incumbent and nonincumbent transmission developers are free to use these same processes for the submission and evaluation of proposals for potential selection in the regional plan for RCAP, these processes are comparable and nondiscriminatory.[84] Section 16.1 further ensures comparability and nondiscrimination by specifying that the evaluation of projects proposed for RCAP will occur "[d]uring the course of the then-current transmission expansion planning cycle (and thereby in conjunction with other system enhancements under consideration in the transmission planning process)."

This avoided transmission costs methodology also satisfies Order No. 1000's six cost allocation principles.[85] Specifically, the costs that would be allocated would be commensurate with the benefits (Cost Allocation Principle 1)[86] because the benefits are the quantifiable benefits of avoided/displaced transmission. This approach complies with Cost Allocation Principle 2[87] and Cost Allocation Principle 4[88] because only a transmission provider/owner in the region that avoids transmission costs would be allocated the cost of the regional project. The SERTP's cost allocation approach also satisfies Cost Allocation Principle 3[89] because it adopts a benefit-to-cost ratio of 1.25. Since the benefits are quantifiable, the cost allocation method and data requirements for determining benefits and identifying beneficiaries would be transparent, satisfying Cost Allocation Principle 5, and there would be sufficient documentation to allow stakeholders to determine how the cost allocation method was applied to a proposed facility.[90]

---

[82] Order No. 1000-A, P 290.
[83] *See Id.*, P 277, *et seq.* (encouraging nonjurisdictional transmission providers to raise their concerns during the development of the regional compliance filings).
[84] Order No. 1000-A recognizes that the adoption of these Order No. 1000 regional cost allocation methodologies "does not undermine the ability of market participants to negotiate alternative cost sharing arrangements voluntarily and separately from the regional cost allocation method or methods." Order No. 1000, P 561.
[85] Cost Allocation Principle 1 provides that costs are to be allocated roughly commensurate with benefits; Cost Allocation Principle 2 provides that there will be no involuntary cost allocation to non-beneficiaries; Cost Allocation Principle 3 provides that if a benefit-to-cost ratio is used, it may not include a ratio exceeding 1.25 absent Commission approval; Cost Allocation Principle 4 provides that cost allocation is to be done solely within the planning region(s) where the facility(ies) is located unless those outside voluntary assume cost responsibility; Cost Allocation Principle 5 requires a transparent method for determining benefits and identifying beneficiaries; and Cost Allocation Principle 6 allows for different cost allocation methods for different types of facilities. *See*, Order No. 1000, P 603, *et seq.*
[86] Order No. 1000, P 622.
[87] *Id.*, P 637.
[88] *Id.*, P 657.
[89] *Id.*, P 646.
[90] *Id.*, P 668.

With regard to Cost Allocation Principle 6,[91] this straight-forward approach would apply to all types of transmission facilities proposed for potential selection in the regional plan for RCAP, regardless of whether those projects were proposed to address underlying reliability, economic, or public policy need, or some combination of the foregoing.

9. Other Attachment K Provisions: Sections 18-21.

With regard to the other Sections of the revised Attachment K being filed hereunder, Section 18 provides for the on-going re-evaluation of projects selected in the regional plan for RCAP to ensure that they remain more efficient and cost-effective alternatives prospectively. This provision is comparable not only because it would apply to both incumbent and nonincumbent projects selected in the regional plan for RCAP, but because Southern Companies and the other SERTP Sponsors continually re-evaluate proposed projects included in their transmission plans as circumstances change and more updated data becomes available.

In accordance with the requirements of Order No. 1000, Section 19 provides for the on-going assessment of whether alternative transmission solutions may be required for a transmission project selected for RCAP due to the delay or abandonment of the project.[92] Section 20 provides for the milestones of required steps necessary to maintain status as being selected in a regional plan for RCAP.[93] Lastly, Section 21 discusses requirements that would be included in the contract(s) that would be necessary to effectuate a transmission project selected in a regional plan for RCAP and for the incumbent to hopefully be able to continue to satisfy its duty to serve requirements.

IV. <u>Request for Waiver</u>

Southern Companies are making this filing in compliance with, but under protest to, the Commission's regional directives in Order No. 1000. By making this filing in compliance with that Order, Southern Companies understand that they have hereby satisfied any of the Commission's filing requirements that might apply. Should any of the Commission's regulations (including filing regulations) or requirements that we may not have addressed be found to apply, Southern Companies respectfully request waiver of any such regulation or requirement.

V. <u>Effective Date</u>

Order No. 1000 acknowledges that it might become effective during the middle of a transmission planning cycle and therefore directed public utility transmission providers to explain in their respective compliance filings how they intend to implement Order No. 1000's requirements.[94] Consistent with the foregoing, Southern Companies are proposing that the OATT provisions being filed hereunder become effective at the start of the next practical

---

[91] *Id.*, P 685.
[92] *See id.*, P 329.
[93] *See* Order No. 1000-A, P 442.
[94] *See* Order No. 1000, P 162.

transmission planning cycle/year following FERC acceptance of this compliance filing, assuming that the Commission largely adopts this filing and issues such an order sufficiently before the beginning of that next year to allow for commencement of implementation. Although Southern Companies and the other SERTP Sponsors expect that the effective date will be January 1, 2014, Southern Companies are using the date 12/31/9998 in their electronic metadata to reflect that there is some uncertainty in this regard. For example, should the Commission require extensive changes, it may not prove feasible to effectuate those changes to the transmission planning process by January 1, 2014.

VI. Service

Southern Companies are serving an electronic copy of this filing to their OATT customers for whom Southern Companies have e-mail addresses and to their State Commissions. In addition, this filing is being posted on the SERTP website, and Southern Companies' are posting an electronic copy of this filing on their OASIS.

VII. List of Documents

The following is a list of documents submitted with this filing:

(a) This transmittal letter, including the following:

  (i) Exhibit A – A map showing the expanded SERTP region and all transmission facilities therein rated higher than 300 kV,

  (ii) Exhibit B – Southern Companies' protest and as-applied challenge to the application of Order No. 1000's regional requirements to them;

(b) Southern Companies' revised Attachment K (including Exhibit K-3) in RTF format with metadata attached;

(c) A clean version of Southern Companies' revised Attachment K (including Exhibit K-3) in PDF format for posting in eLibrary; and

(d) A redline version of Southern Companies' revised Attachment K (including Exhibit K-3) in PDF format for posting in eLibrary.

VIII. Miscellaneous

Should additional information be required, it is requested that Ms. Julia L. York, Transmission Policy Analyst, Southern Company Services, Inc., Post Office Box 2625, Birmingham, Alabama 35202-2625, or the undersigned attorney be contacted at the earliest possible date so that such information can be supplied expeditiously.

Sincerely,

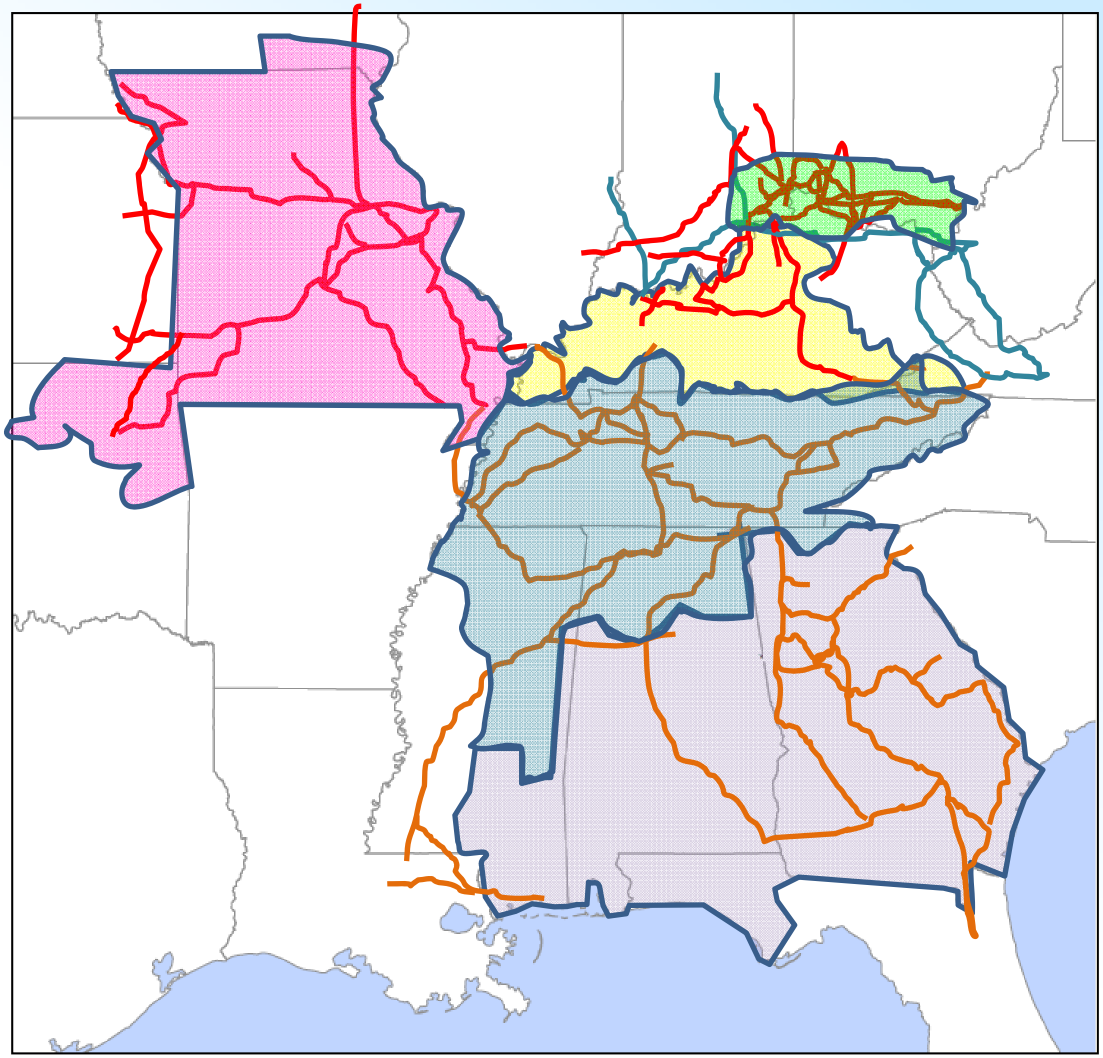
/s/ Andrew W. Tunnell
Andrew W. Tunnell
Attorney for Southern Company Services, Inc.

Of Counsel:
BALCH & BINGHAM LLP
Andrew W. Tunnell
Jesse S. Unkenholz
P. O. Box 306
Birmingham, AL 35201
(205) 251-8100 (telephone)
(205) 226-8798 (fax)

EXHIBIT A

A MAP SHOWING THE EXPANDED SERTP REGION AND ALL TRANSMISSION FACILITIES THEREIN RATED HIGHER THAN 300 KV

SERTP – 300 kV+ Backbone



The diagram above depicts key high voltage facilities within the SERTP region. All facilities shown may not be owned by an SERTP Sponsor.

EXHIBIT B

SOUTHERN COMPANIES' PROTEST AND AS-APPLIED CHALLENGE TO THE APPLICATION OF ORDER NO. 1000'S REGIONAL REQUIREMENTS TO SOUTHERN COMPANIES

I. Southern Companies' Protest and Objection to the Application of Order No. 1000.

Southern Companies are making this compliance filing to Order No. 1000's[1] regional transmission planning and cost allocation requirements under protest and with reservation of all rights to continue to challenge the directives thereof, either on a facial or an as-applied basis. Southern Companies and others sought and were denied rehearing of Order No. 1000 regarding the basis for and legality of the Order as a whole and all or some of the requirements thereof. Southern Companies' petition for review of Order No. 1000 is currently pending before the United States Court of Appeals for the District of Columbia Circuit and has been consolidated with numerous other petitions for review of the Order. Southern Companies, therefore, submit this compliance filing under protest and on a provisional basis, subject to the disposition of the petitions for review, and reserve the right to withdraw or amend this filing or otherwise make appropriate filings reflecting the judicial disposition of these matters.

By this protest, Southern Companies object to the application to them of Order No. 1000's regional requirements. Southern Companies are prompted to do more than simply protest the filing, and are including the following "as–applied" challenge, due to representations by the Commission's Solicitor's Office that the Commission intends to raise standing and ripeness defenses before the D.C. Circuit Court of Appeals. Southern Companies find no merit in such assertions; nevertheless, they necessitate the lodging of the following as-applied challenge as a precautionary measure. Furthermore, Southern Companies reserve the right to file additional materials and bring future challenges related to Order No. 1000 as events unfold, including to any future applications of the requirements of Order No. 1000 to them.

II. Order No. 1000's Requirements, as Applied to Southern Companies, Are Unlawful

A. The Order's Conclusion that the Existing Transmission Planning Processes in the Southeast are Unjust, Unreasonable, and Unduly Discriminatory is Refuted by the Facts

The application of the Order's regional requirements to Southern Companies fails to satisfy the first prong of the Commission's Section 206[2] burden of proof to establish that Southern Companies' existing regional transmission planning processes are unjust, unreasonable, and unduly discriminatory. As demonstrated by the record underlying the Order No. 1000 rulemaking,[3] the "problems" that the Commission stated that it sought to address in Order No. 1000 are not issues for Southern Companies or, for that matter, the Southeast in general. Southern Companies' transmission planning processes and those of the Southeast in general are already thoroughly coordinated and demonstrably able to address whatever challenges are reasonably foreseeable to the transmission system.[4] Public policy requirements are already

[1] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* 136 FERC ¶ 61,051 (2011), *order on reh'g and clarification*, 139 FERC ¶ 61,132 (2012) ("Order No. 1000-A"), *order on reh'g and clarification*, 141 FERC ¶ 61,044 (2012) ("Order No. 1000-B") (Order Nos. 1000, 1000-A, and 1000-B collectively referred to as "Order No. 1000," "Order," or "Final Rule").

[2] 16 U.S.C. § 824e.

[3] *See* Docket No. RM10-23.

[4] While the SERTP has recently been expanded, it bears noting that this expansion was not required for Southern Companies to satisfy the requirements of Order No. 1000 because the original scope of the SERTP already constituted a valid transmission planning region. *See* Transmittal Letter, at pp. 4-5. Moreover, all of the utilities in

incorporated into transmission planning on a "bottom-up" basis.[5] Southern Companies do not have a federal right-of-first refusal. Furthermore, because the transmission system is already being expanded as needed and as appropriate, Order No. 1000's cost allocation requirements are not necessary or appropriate to remedy undue discrimination or to establish just and reasonable rates, terms, or conditions for transmission service.[6]

As part of their comments and request for rehearing filed in the Order No. 1000 proceeding, Southern Companies filed evidence establishing the foregoing in the form of affidavits and a paper providing an overview of their system that we incorporate by reference here. This evidence remains unrefuted.[7] The gravamen of those evidentiary materials, along with other information and evidence otherwise available to the Commission,[8] is that Southern Companies' transmission system, and the transmission system of the Southeast in general, is robust and reliable. The effectiveness of this system is largely a product of the effective integrated resource planning and transmission planning and coordination processes that are

---

the expanded SERTP already engage in coordinated transmission planning. Explanations of how Southern Companies' and the other transmission providers in the Southeast already engage in thoroughly coordinated transmission planning are found at: the Transmittal Letter to which this protest is attached at p. 10; Expert Testimony of Bryan K. Hill included as an Affidavit to Southern Companies' filings in the Order No. 1000 rulemaking proceeding ("Hill NOPR Affidavit") and that is being resubmitted herein as Attachment B-1 at PP 10-15; Expert Testimony of Garey C. Rozier included as an Affidavit to Southern Companies' filings in the Order No. 1000 rulemaking proceeding ("Rozier Affidavit") and that is being resubmitted herein as Attachment B-2 at PP 19, 25-40; Supplemental Affidavit of Bryan K. Hill included as an Affidavit to Southern Companies' Request for Rehearing to Order No. 1000 ("Supplemental Hill Affidavit") and that is being resubmitted herein as Attachment B-3 at PP 4-8; "Overview of the Transmission System in the Southern Company Area" that was included in Southern Companies' filings in the Order No. 1000 rulemaking proceeding and is being resubmitted herein as Attachment B-4 at pp. 2-3; and Section 6 (entitled, "Regional Participation") of Southern Companies' Attachment K. As discussed on page 3 of the Transmittal Letter, even further coordination will be provided by the expansion of the SERTP. As indicated by the foregoing, given the importance of these factual showings to this proceeding, and to facilitate review, the Hill NOPR Affidavit, the Rozier Affidavit, the Supplemental Hill Affidavit, and the "Overview of the Transmission System in the Southern Company Area" are being filed herein and are incorporated herein by reference.

[5] *See, e.g.,* Rozier Affidavit, PP 20-26.

[6] It is not appropriate to use possible localized or regional-specific problems to justify a nationally applicable set of rules, particularly when there are established regional differences in how transmission planning is performed and how services are delivered. Therefore, the Order's requirements should not be placed upon Southern Companies because there is no evidence that the Southeast exhibits such a problem. *See, e.g., United States Telecom Association v. FCC*, 290 F.3d 415 (D.C. Cir. 2002) (overturning agency rule for promulgating a nation-wide remedy when there was only evidence that abuse occurred in certain regions and there was no evidence of abuse in other regions); *see also Interstate Natural Gas Association v. FERC*, 285 F.3d 18, 37-38 (D.C. Cir. 2001); *Associated Gas Distributors v FERC*, 824 F.2d 981, 1019 (D.C. Cir. 1987); *Interstate Natural Gas Association of Am. v. FERC*, 285 F.3d 18, 37 (D.C. Cir. 2002).

[7] *See* Hill NOPR Affidavit, PP 3-16; Supplemental Affidavit of Bryan K. Hill; Rozier Affidavit; "Overview of the Transmission System in the Southern Company Area."

[8] *See, e.g.,* NERC's 2012 Long-Term Reliability Assessment (November 2012) ("NERC 2012 Assessment"), available at: http://www.nerc.com/files/2012_LTRA_FINAL.pdf; NERC's 2011 Summer Reliability Assessment at 138-141 (May 2011) ("2011 Summer Assessment"), available at http://www.nerc.com/files/2011%20Summer%20Reliability%20Assessment_FINAL.pdf; NERC's, 2010 Long-Term Reliability Assessment at 22 (October 2010) ("NERC 2010 Assessment"), available at http://www.nerc.com/files/2010%20LTRA.pdf.; DOE's 2009 Transmission Congestion Study ("2009 Congestion Study") (Section 216(a) of the Federal Power Act ("FPA") requires DOE to perform such a congestion study every three years.); 16 U.S.C. § 824p(a)(1)); information is also available through regulatory submissions already in FERC's possession, such as, *inter alia*, FERC Form 1 and FERC Form 715.

utilized by Southern Companies and other transmission owners in this area of the country. Southern Companies' transmission system, and that of SERC in general, is characterized by (a) superb maintenance of the largest transmission system (for SERC), by number of circuit miles, within the Eastern Interconnection; [9] (b) comprehensive investment in new transmission infrastructure (Southern Companies invested over $2.1 billion in upgrading and expanding transmission infrastructure during the 2006-2010 period alone); and (c) a general dearth of (i) delay in completing infrastructure build-out and (ii) recurring congestion.

The Commission and DOE both have recognized that the transmission planning and cost allocation processes in the Southeast have resulted in more than adequate investment in, and development of, necessary transmission infrastructure. For example, then-Chairman Kelliher noted at a FERC technical conference that the "southeast has done a very good job on investing in transmission . . . ." [10] DOE's 2009 Congestion Study ultimately concluded: "Because southeastern utilities build aggressively in advance of load, there is little economic or reliability congestion within the region." [11] Of particular importance to the application of Order No. 1000's requirements to Southern Companies, the DOE concluded that there is little congestion within the Southeast region due to the effectiveness of the transmission planning performed in this region: "***SERC region has a unique philosophy with respect to electric system planning and construction***" in that "[t]he transmission system within SERC has been planned, designed and is operated such that the utilities' generating resources with firm contracts to serve load are not constrained." [12]

The record evidence is clear – and unrefuted – that Southern Companies' electric system and those of many of its neighboring systems are already robust, and the reason for this positive result is the "***unique philosophy with respect to electric system planning and construction.***" [13] The Order's use of mere hypothesis to declare that these very same planning processes are unjust and unreasonable is, thus, contrary to the record evidence. Accordingly, the application of the Order's regional requirements to Southern Companies fails the first prong of the Commission's Section 206 burden of proof, is *not* supported by substantial evidence, and is otherwise arbitrary and capricious.

---

[9] In this regard, even though MISO and PJM have more load than the expanded SERTP, with PJM having one-third more load than the SERTP, the SERTP has more circuit miles of transmission than either. *See NERC 2011 Long-Term Reliability Assessment*, pp. 34 and 46 (providing that MISO has a peak of 98,068 MW with 50,144 circuit miles of transmission, that PJM has a peak of 148,941 MW with 53,079 circuit miles and that the expanded SERTP has a total peak load of approximately 96,000 MWs and approximately 66,000 circuit miles of existing transmission).

[10] *Conference on Competition in Wholesale Power Markets*, Docket No. AD07-7-000, Technical Conference Transcript at 271 (Feb. 27, 2007).

[11] 2009 Congestion Study at 60-61; *see also* Pre-Congestion Study Regional Workshop for the 2009 National Electric Congestion Study, Atlanta, Georgia, Transcript (July 29, 2008) at 3, 7, available at http://congestion09.anl.gov/documents/docs/Transcript_Pre_2009_Congestion_Study_Atlanta.pdf.

[12] 2009 Congestion Study at 60 (emphasis added) (*quoting* NERC, 2009 Summer Reliability Assessment at 131, available at http://www.nerc.com/files/summer2009.pdf)).

[13] 2009 Congestion Study at 60 (emphasis added).

B. The Record Evidence Refutes the Order's Conclusion that its Proposed Transmission Planning Reforms Are Just and Reasonable

The application of the Order's regional requirements to Southern Companies also fails to satisfy the second prong of FERC's Section 206 burden of proof, namely that its imposition of additional transmission planning requirements must be just and reasonable.[14] While the Order does not, and cannot, show that Southern Companies' existing planning processes violate Section 206, record evidence and judicially-accepted economic realities establish that requiring Southern Companies to comply with Order No. 1000's regional planning mandates will actually *harm*, not benefit, consumers – a result that can hardly be considered just and reasonable. Likewise, rather than facilitating Southern Companies' ability to plan and expand the transmission system to meet their load service requirements, the Order's compliance requirements will *harm* Southern Companies' ability to do so. Such a result is also contrary to FPA Section 217(b)(4),[15] and is otherwise contrary to law, arbitrary, and capricious.[16]

1. The Record Evidence Refutes the Order's Theory-Based Conclusion that its Proposed Transmission Planning Reforms Are Likely to Produce Meaningful Benefits

The Order asserts the theory that its proposed additional regional requirements are just and reasonable because they may lead to the identification of more efficient and cost effective transmission solutions.[17] This theory is refuted by the fact that the existing regional (as well as interregional) transmission planning in the Southeast is already highly effective, and the bottom-up IRP and RFP planning processes that drive such transmission planning processes already thoroughly canvass both regional and interregional resource opportunities. Accordingly, there are no transmission planning "gaps" that will be filled by complying with the Order's requirements. Transmission planning in the Southeast plans for the expansion of the transmission system to address three incremental needs: i) load growth (as identified in underlying IRP processes);[18] ii) the integration of new generating resources (as identified in underlying IRP/RFP processes); and iii) long-term firm requests by third parties under an Open Access Transmission Tariff ("OATT").[19] These planning activities already occur in a coordinated fashion through the existing bottom-up planning processes. Since the Order's required additional level of regional transmission planning will not be associated with addressing any previously unidentified, new need for transmission, there will be no catalyst for such regional planning to actually identify any additional regional transmission facilities.[20] Without

---

[14] *See Atlantic City*, 295 F.3d at 10 ("In order to make any change in an existing rate or practice, FERC must first prove that the existing rates or practices are 'unjust, unreasonable, unduly discriminatory or preferential.' 16 U.S.C. § 824e(a); *see Alabama Power Co. v. FERC*, 993 F.2d 1557, 1569 (D.C.Cir.1993). *Then FERC must show that its proposed changes are just and reasonable*. *Tennessee Gas Pipeline Co. v. FERC*, 860 F.2d 446, 454 (D.C.Cir.1988)." (emphasis added)).

[15] 16 U.S.C. § 824q.

[16] *See* 5 U.S.C. § 706.

[17] *See, e.g.,* Order No. 1000, P 78; Order No. 1000-A, P 3.

[18] The nonjurisdictional transmission providers/owners in the Southeast perform such load growth and resource analyses through internal processes.

[19] Hill NOPR Affidavit at P 8.

[20] *See, e.g.,* Supplemental Hill Affidavit at P 15.

any new catalyst to drive new transmission construction, merely requiring transmission providers to engage in additional coordination is highly unlikely to result in the identification of more appropriate transmission upgrades.

Moreover, while there may be an opportunity in other regions for increased coordination or nonincumbent developer proposals to identify more efficient or cost effective transmission solutions, this is not the case for Southern Companies or the Southeast in general. As for other areas of the country, such an opportunity presumably arises in regions characterized by high transmission congestion or the need to integrate remotely located renewable generation. The Southeast has neither. With regard to congestion, "in bilateral markets such as Southern Companies, there is no need for additional transmission expansion to relieve congestion because the system is planned from the outset to eliminate congestion for long-term firm delivery of power."[21] As recognized by the Department of Energy in its 2009 Congestion Study, "[b]ecause the southeastern utilities build aggressively in advance of load, there is little economic or reliability congestion with the region."[22] With regard to remotely located renewable generation, hydroelectric, solar and biomass generating resources have been and are being integrated without the need for major transmission expansion. The economic viability of wind generation has faced challenges given the lower wind speeds typical to the region,[23] but to the extent projects emerge, they likewise would not require significant transmission expansion.

2. Order No. 1000's Mandates Requiring Nonincumbents to Develop Regional Transmission Projects Will Reduce Southern Companies' Vertical Integration and Thereby Harm Consumers.

Requiring Southern Companies to comply with Order No. 1000's nonincumbent requirements sets into motion FERC-mandated processes that erode Southern Companies' vertical integration and undermine the regulatory compact they hold with the states whose electric customers they serve at retail. As a result, efficiencies are lost and consumers are harmed.

The economic benefits provided by vertical integration are long recognized, and include such aspects as: "(1) technological interdependencies; (2) transmission of more efficient price signals between vertical levels; (3) reduction in transaction costs; (4) improvement in information flow; and (5) lowered costs of uncertainty and risk."[24] When coupled with operation under the traditional regulatory compact and the concomitant duty to serve, the benefits of

[21] Supplemental Hill Affidavit at P 14.
[22] 2009 Congestion Study, at 60-61.
[23] Nevertheless, Southern Companies have aggressively imported wind generation from the Southwest. *See* American Wind Energy Association Press Release, *Alabama Power recognized for saving its Southeastern customers money with wind power from TradeWind Energy of Kansas*, available at: http://www.awea.org/newsroom/pressreleases/Alabama-Power-recognized-for-saving-its-Southeastern-customers-money-with-wind-power-from-TradeWind-Energy-of-Kansas.cfm (Announcing AWEA's awarding Alabama Power Company the "Outstanding Commercial Achievement Award" for "helping to bring cost-effective wind power to the Southeast, along with TradeWind Energy, the Kansas company from which it's purchasing the electricity.").
[24] John H. Landon, Theories of Vertical Integration and their Application to the Electric Utility Industry, 28 Antitrust Bull. 101 (1983).

vertical integration ensure, among other things, that transmission is constructed as necessary and on schedule and then is appropriately operated, maintained, and (when required) restored.[25] The courts have recognized these types of benefits provided by the vertical integration of electric utilities and have held that some showing must be made by FERC to support its mandates that undermine such vertical integration.[26]

In response to arguments by Southern Companies that the Order's nonincumbent requirements would so undermine Southern Companies' vertical integration, Order No. 1000-A simply deflects, asserting that "Southern Companies confuse the concept of vertical integration with monopoly."[27] Southern Companies respectfully disagree. Vertical integration has been defined as the "form of business organization in which all stages of production of a good, from the acquisition of raw materials to the retailing of the final product, are controlled by one company."[28] Since the development by a nonincumbent of such a transmission facility would diminish Southern Companies' integrated control of the electric system necessary for them to move their product (*i.e.*, electricity) to their customers, Order No. 1000's nonincumbent requirements diminish Southern Companies' vertical integration.[29]

The loss of that vertical integration will harm consumers through the erosion of scale economies with respect to, among other things, operation, maintenance, and emergency (storm) response. The harm will be compounded by the imposition of additional costs by the nonincumbent, who necessarily will lack the efficiencies and capabilities of the franchised utility transmission provider, which expanded the transmission grid under the guidance of its State regulators, as the customer base grew and demand increased, as well as by the additional uncertainties and risks to the provision of service posed by the nonincumbent.[30] Such a construct does not benefit customers and is not just and reasonable. Further, this very erosion of vertical integration demonstrates the underlying defect in the theoretical positions the Order takes. Established economic theory overwhelmingly supports the proposition that in natural monopoly

[25] *See, generally*, Testimony of David Ratcliffe, President and CEO, Southern Company, before the Senate Committee on Homeland Security and Governmental Affairs (November 16, 2005) available at http://hsgac.senate.gov/public/_files/111605Ratcliffe.pdf (describing the benefit of Southern Companies' vertical integration in restoring service expeditiously in response to the historic damage caused by Hurricane Katrina). Even more recently, a severe tornado outbreak swept through Southern Companies' service territory on April 27, 2011 requiring yet another massive restoration effort. *See e.g.*, Mike Oliver, "Day of devastation in Alabama: At least 128 killed by storms," *The Birmingham News* (April 28, 2011), available at http://blog.al.com/spotnews/2011/04/street-by-street_search_effort.html.

[26] *See National Fuel*, 468 F. 3d at 841 ("We begin by emphasizing that vertical integration creates efficiencies for consumers."); *Id.* at 844 (FERC must show why the costs of its prophylactic rules are justified, in the absence of a finding of abuse); *Tenneco*, 969 F.2d at 1201 ("*[V]ertical integration produces permissible efficiencies that "cannot by themselves be considered uses of monopoly power*.") (emphasis added)).

[27] Order No. 1000-A, P 90.

[28] *Encyclopedia Britannica*, http://www.britannica.com/search?query=vertical+integration; *see also Paschall v. Kansas City Star Co*., 727 F.2d 692, 697 n. 3 (8th Cir. 1984).

[29] The court in *National Fuel* further explained with regard to *structural* separation that "there are efficiencies to be derived from such integration and *any* separation reduces those benefits to some extent." 468 F. 3d at 841 (*quoting Tenneco*, 969 F.2d at 1197).

[30] *See, e.g.*, Report of the North Carolina Utilities Commission, Docket No. E-100, Sub 132, Investigation of Federal Requirement to Consider Transmission Ownership by Non- Incumbent Developers (issued October 11, 2012) ("NCUC Report").

industry segments,[31] such as electric transmission/distribution and other traditionally regulated sectors, efficiency is gained by the *reduction* of suppliers in the chain of supply, not the addition of suppliers as the Order would have it. Indeed, this is the underlying principle of a natural monopoly.

3. Complying with Order No. 1000's Requirements Allowing Nonincumbents to Develop Transmission Lines that Southern Companies Need to Meet Their Native Load Obligations Will Harm Southern Companies' Ability to Expand the System and Will Threaten Reliability.

Section 217(b)(4) requires the Commission to exercise its authority to facilitate the transmission planning and expansion needed by load serving entities to meet their load service needs. In this regard, Southern Companies are the load serving entities for their load served off of their transmission system. To date, Southern Companies have been able to plan and expand their system in a manner reasonably efficacious to the provision of reliable and economic service to their customers. Indeed, the evidence available to FERC indicates that Southern Companies have a sterling record in meeting in-service dates.[32]

Complying with Order No. 1000's requirements will require Southern Companies to allow nonincumbents to develop the transmission lines that Southern Companies need to meet their load service needs. This imposition of a third party will not facilitate Southern Companies' ability to expand their system. Rather than Southern Companies being able to directly construct, own, operate, and maintain the transmission facilities that they need to serve their load (benefits associated with their vertical integration), Southern Companies face the prospect of being forced to rely upon a third party to do so. While Southern Companies have tried to develop qualification criteria and other tariff provisions that would best protect their customers from the risks of a nonincumbent's failure to properly develop a transmission project, those provisions are no guarantee that a nonincumbent will be able to match Southern Companies' record of not missing in-service dates for needed transmission or that the nonincumbent will expand, maintain, operate, and restore the system in a manner needed in order for Southern Companies to meet their load service needs. For example, if a nonincumbent transmission developer having a project selected for RCAP finds itself in bankruptcy, then the entire development process for the transmission project at issue could essentially be held in limbo until the bankruptcy is resolved by operation of the bankruptcy court's "automatic stay" authority.[33] The forced imposition of Order No. 1000's nonincumbent model thus imposes new risk elements that inevitably will result

[31] *See, e.g.*, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, 31,649 (1996) ("In 1994 in the KCP&L case . . . , the Commission continued to recognize that transmission remains a natural monopoly."); *id.* at 31,652 ("[T]ransmission service continues to be a natural monopoly." (footnote omitted)); *id*. at 31,872 n. 974 ("Transmission, on the other hand, will remain a regulated monopoly function."); *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County, Washington*, 554 U.S. 527, 536 (2008); *Tenneco*, 969 F. 2d at 1201. In Order No. 1000, the Commission failed to adequately explain its change from this precedent that transmission is a natural monopoly. *See Motor Vehicle Manufacturers Association of the United States, Inc. v. State Farm Mutual Automobile Insurance Co.*, 463 U.S. 29, 42 (1983); *City of Charlottesville, Virginia v. FERC*, 661 F. 2d 945, 951 n. 35 (D.C. Cir. 1981).

[32] *See, e.g.*, Hill NOPR Affidavit, 2009 Congestion Study, and information reporting, such as FERC Form 1.

[33] *See*, 11 U.S.C. § 362.

in increased costs. Moreover, Southern Companies currently have complete flexibility in revising the schedule for the development of any of its transmission projects, being able to accelerate, postpone, or even cancel a project as determined appropriate in any subsequent transmission planning analysis. It is highly unlikely that the Order's requirement that Southern rely upon a third party will allow for such flexibility.[34] Therefore, the application of the Order's nonincumbent requirements to Southern Companies will increase risks to customers and place increased pressure on rates.[35]

Order No. 1000 itself recognizes that delay or abandonment by a nonincumbent could pose reliability problems,[36] but then fails to adequately address those problems. Southern Companies provided an extended explanation, in its Request for Rehearing, of the infirmity of Order No. 1000's requirement that transmission providers reevaluate projects to determine if alternatives solutions should be pursued in the event of a project delay. Southern Companies reassert those objections here.[37] In Order No. 1000-A, FERC responded by essentially holding that the current NERC standards and operational procedures already establish sufficient requirements upon "a Functional Entity . . . [to] prepare its system to operate regardless of whether a transmission project is delayed or abandoned."[38] This holding, however, does not even address the problems raised – which is the diminution of electric service to customers as a result of nonincumbent action (or inaction). As explained in the Supplemental Hill Affidavit, nonincumbent delay or abandonment could result in the exercise of the following operational procedures that are allowed under NERC-operational standards: (1) reconfiguration of the system; (2) uneconomic dispatch; (3) curtailing interchange schedules; and (4) load shedding.[39] The application to Southern Companies of a rulemaking that increases the likelihood of such events must be arbitrary and capricious, and it is not saved simply because those procedures have been established (indeed, being forced to utilize those procedures is the problem, not the solution).[40] A goal of effective transmission planning (as well as Congress' goal in adopting Section 215 of the Federal Power Act, NERC's goal in adopting transmission planning ("TPL") standards, and the Commission's goal in requiring such TPL standards)[41] is to maintain and increase reliability, not diminish it. The Commission has thus acted arbitrarily and capriciously, and its actions are thus not in accordance with law.[42]

---

[34] Rozier Affidavit, P 37.

[35] *See also, e.g., Report of the North Carolina Utilities Commission, Investigation of Federal Requirements to Consider Transmission Ownership by Non-Incumbent* Developers, Docket No. E-100, Sub 132, at pp. 16-17 (NCUC 2012) (finding the Order No. 1000's nonincumbent developer requirements pose the following risks to North Carolina consumers: 1) increased risks of higher payments associated with incentive rates; 2) reliability risks associated with nonincumbent abandonment or delay; 3) risks of substandard construction by the nonincumbent or its failure to adequately maintain its project; and 4) risk the nonincumbent would fail to timely restore facilities following outages).

[36] Order No. 1000, P 329.

[37] *See* Request for Rehearing, pp. 74-84.

[38] Order No. 1000-A, P 478.

[39] *See* Supplemental Hill Affidavit, PP 30-40.

[40] While Southern Companies appreciate statements in Order Nos. 1000 and 1000-A designed to insulate transmission providers from facing penalties for reliability violations resulting from the abandonment or delay caused by nonincumbent developments, which is surely just, such penalties are not the actual "harm" caused by such abandonment or delay. Instead, it is this identified reduction of service that is the real harm, as it will befall the transmission provider's customers.

[41] *See* 16 U.S.C. § 824o.

[42] *See* 5 U.S.C. § 706.

And it bears emphasizing that Southern Companies, with their regulated franchise and state-imposed duties of service,[43] have a far greater incentive to ensure that their transmission projects are placed into service on-time and thereafter operated, maintained, and (if necessary) restored in an appropriate manner than would a nonincumbent developer. Should Southern Companies fail to adequately perform these duties, they face the scrutiny of their State regulators, thereby potentially affecting their overall provision of bundled retail service. On the other hand, a nonincumbent that fails to perform could just declare bankruptcy and even terminate its corporate existence (and thereby largely insulate its parent company from possible ramifications). For Southern Companies, their commitment to the provision of reliable and economic service to their customers goes far beyond the development of any single transmission project.

4. Complying with Order No. 1000's Nonincumbent and Cost Allocation Requirements will Harm Transmission Planning and Expansion by Making the Process More Bureaucratic and Contentious

In developing the changes to their Attachment K, Southern Companies have striven to adopt provisions that are tailored to both comply with the Order while being the least likely alternative to prove disruptive to the planning and expansion of their transmission system and to the provision of electric service to their customers. Nevertheless, should Southern Companies receive proposals for transmission projects submitted for RCAP purposes, it is reasonably foreseeable, given the inherently contentious nature of such a process (with the possibility of disputes and even litigation at every step of the process), that Southern Companies' ability to plan and expand their transmission system will be harmed, thereby further reinforcing that the application of Order No. 1000 to Southern Companies violates FPA Section 217(b)(4).[44]

C. Order No. 1000's Requirements Violate FPA Section 202(a).

Section 202(a) provides for the "voluntary interconnection and ***coordination*** of ***facilities*** for the . . . ***transmission*** . . . of electric energy...."[45] Applying Order No. 1000's requirements to Southern Companies violates this statute by requiring them to adopt OATT provisions that ***force*** them to coordinate with nonincumbent developers and potentially require Southern Companies to coordinate with other transmission providers to an extent further than they would otherwise agree to do. Thus, Order No. 1000 mandates the very acts that 202(a) dictates must be voluntary.

III. The Commission's Prohibition Preventing Southern Companies from Adopting a Participant Funding-Based Cost Allocation Methodology was Arbitrary and Capricious

Order No. 1000's categorical prohibition on participant funding as a region's cost allocation method is arbitrary and capricious. Participant funding aligns with the familiar "cost-causation" principle, in that those who value the construction of a new facility the most (and thus

[43] *See, e.g.*, Ala. Code § 37-1-49.
[44] Accordingly, should Southern Companies ever receive a transmission proposal seeing RCAP pursuant to the new portions of Attachment K contained in this filing, Southern Companies reserve the right to again challenge Order No. 1000 in that context.
[45] 16 U.S.C. § 824a(a)(emphasis added).

"cause" the cost to be undertaken) pay for its construction. In the Southeast and for Southern Companies, consistent with the alignment of cost causation with cost allocation, the system is expanded for the benefit of those who make the necessary long-term firm commitments necessary to fund the expansion. Specifically, those who will benefit from a transmission project are identified through the integrated resource planning process or through requests for transmission service – and the resulting allocation of costs to grid participants (be they aggregated as retail load or otherwise) is just and reasonable and does not result in any "free rider" effect. As noted in this pleading and demonstrated in the record, the fear of "free riders" taking advantage of participant funding mechanisms is not a problem in the Southeast. Among other things, Southern Companies' provide "physical" transmission service that requires an entity to purchase transmission service in order to scheduled deliveries. Further, the Order strongly suggests that FERC has authority to allocate costs between entities where no voluntary contractual relationship exists, a proposition that is refuted by judicial precedent.[46]

In addition, Order No. 1000-A found that participant funding does not align with the Commission's goals of the Final Rule because such an approach to cost allocation is not capable of defining project benefits in regional or interregional terms.[47] This finding is confusing, as participant funding identifies the very parties who need the facility built (*e.g.*, native load served under statutory regulatory compact, firm point-to-point service under long-term transmission service agreements) regardless of their physical location. Thus, contrary to the Commission's incorrect assumption that participant funding is predicated only upon preexisting voluntary contracts, "participant funding" provides an excellent mechanism for the allocation of costs to identified beneficiaries and is consistent with the existing practices in the Southeast of aligning the cost allocation for system expansion with the cost causer. Moreover, it avoids the infirmity created by the lack of FPA-required contractual privity with those to whom costs are allocated. As demonstrated herein and in the record, with respect to the Southeast, at least, participant funding should not be excluded *per se* as a regional cost allocation method, and the Commission acted arbitrary and capriciously in precluding the use of such a just and reasonable methodology.[48]

IV. Order No. 1000's Requirements Violate Section 201 of the Federal Power Act

Order No. 1000-A sought to diffuse concerns that its requirements would interfere with matters traditionally reserved for the states, stating that "Order No. 1000's transmission planning reforms are concerned with process; these reforms are not intended to dictate substantive outcomes, such as what transmission facilities will be built and where."[49] But such dictation is precisely what the Order does. By subjugating transmission planning decisions and the siting

---

[46] *See, e.g., Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County, Washington,* 554 U.S. 527, 533 (2008) (*citing* and *quoting* with approval *Permian Basin Rate Cases*, 390 U.S. at 822) ("[T]he regulatory system created by the FPA is premised on contractual agreements voluntarily devised by the regulated companies.").
[47] *See*, Order No. 1000-A, P 727.
[48] Indeed, Commission policy generally accepts participant funding as a just and reasonable cost allocation methodology for merchant transmission developers. *See, generally* Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects, Final Policy Statement, 142 FERC ¶ 61,038 (2013) (and cases cited therein).
[49] Order No. 1000-A, P 188.

and construction approvals of State regulators to the outcome of such FERC process, Order No. 1000 unlawfully expands FERC's jurisdiction at the expense of transmission planners and state authorities.

The Federal Power Act is clear that the jurisdiction of the Commission extends "only to those matters which are not subject to regulation by the States,"[50] and that the Commission may not do indirectly what it is prohibited from doing directly.[51] The Commission has recognized, including in the Final Rule, that construction and siting are two such areas of traditional state regulation. Although the Order at times seeks to disclaim doing so, the inevitable consequence of its requirements is the erosion of State jurisdiction over siting and construction to the Commission. Simply put, transmission planning, siting, and construction are intrinsically linked, and the Commission's assertion of jurisdiction over planning effectively regulates the siting and construction matters that remain the sole prerogative of the States.

While Order No. 1000 claims that the Commission is only regulating the "process" of transmission planning and not the substantive decisions, the fact remains that the Commission will be the arbiter of disputes that arise from those processes.[52] Moreover, whether or not third party complaints challenging planning or cost allocation decisions made pursuant to Order No. 1000-mandated processes are ever filed — through a Section 206 complaint or otherwise — the fact remains that FERC now taken for itself the ***ability*** to exercise the authority in a way that it did not prior to Order No. 1000 over the substantive planning decisions that drive siting and construction decisions.[53] For example, a transmission provider choosing to extend an already State-certificated facility faces the prospect of that State-sanctioned decision being undone at the hands of action taken in accordance with Order No. 1000, through (for example) FERC adjudicating a dispute over what facility should be included in the "regional plan" or by FERC deciding the cost allocation/recovery for the concerned facilities. Thus, leaving aside the risks such an outcome poses to the transmission provider and its customers, the fact of such a prospect represents the undermining of State authority, to the aggrandizement of the Commission. This alone violates the Federal Power Act.

Equally disconcerting though are the destabilizing consequences of an actual exercise of such authority by the Commission. How will a transmission provider and its State regulator be able to confidently plan when a facility, identified as needed for expanding load in the region (due, for example, to economic expansion associated with a rebounding economy), sited and under construction, has the potential to be declared by the Commission as the "wrong" facility from the transmission plan? Must customers bear the costs of a facility ordered abandoned in lieu of a new facility? Is the transmission provider required to construct the facility anyway, in accordance with the direction from its State authorities, only to have recovery of its costs

[50] 16 U.S.C. § 824(a).

[51] *See, generally, Northern Gas Co. v. Kansas Comm 'n.*, 372 U.S. 84, 91-93 (1963); *Towns of Concord, Norwood, and Wellesley, Mass. v. FERC*, 955 F. 2d 67, 71 n. 2 (D.C. Cir. 1992) (*quoting AGD*, 898 F. 2d at 810 (per curiam) (Williams, J., concurring))); *see also, American Gas Ass'n v. FERC*, 912 F. 2d 1496, 1510 (D.C. Cir. 1990).

[52] *See* Order No. 1000-A, P 231.

[53] The Commission itself may, without action from any interested party, initiate Section 206 proceedings whenever it disagrees with the outcome of the mandated processes, the same authority it asserted *sua sponte* in the Order No. 1000 proceeding. Through the extra-jurisdictional exercise of the mandates in the Final Rule, the Commission provides itself backstop planning authority over all planning processes.

disallowed by FERC? Regardless of the outcome in that situation, the lasting effects on future decisions will be far-reaching. Indeed, future decisions finding the "right" solution will be as influenced by the action of the Commission as the decisions deemed "wrong" by the Commission. At that juncture, States' residual Section 201 authority will be a shadow of what Congress intended and what they possessed prior to Order No. 1000.[54]

[54] After all, to decide which transmission projects are going to receive funding is to decide which projects are going to be pursued. If the transmission provider's alternatives are to either (i) make a planning decision (which would likely lead to siting and construction decisions) with which it disagrees but is sought by the Commission or (ii) forego cost recovery or even possibly face civil penalties or other punitive actions in the name of unjust and unreasonable rates or undue discrimination, then there is no real choice.

ATTACHMENT B-1

EXPERT TESTIMONY OF BRYAN K. HILL

Originally Included as “Attachment A” to Southern Companies’ Initial Comments and “Exhibit 2” to Southern Companies’ Request for Rehearing

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation	)	Docket No. RM10-23-000
by Transmission Owning and Operating	)	
Public Utilities	)	

AFFIDAVIT OF BRYAN K. HILL

I, Bryan K. Hill ("Affiant"), being duly sworn, depose and state as follows:

1. My name is Bryan K. Hill. I am employed by Southern Company Services, Inc., and my business address is 600 18th Street North, Birmingham, Alabama 35291. Currently, I am employed as Planning Manager for Southern Company Transmission, Transmission Planning. My responsibilities and duties as Planning Manager include the oversight of regional, inter-regional and interface planning as well as oversight of all transmission service studies conducted under the Southern Companies' Open Access Transmission Tariff. I graduated from Auburn University in 1995 with a bachelors' degree in Electrical Engineering. I have over fifteen (15) years of experience in the utility industry including distribution engineering, distribution planning, transmission planning, transmission service and transmission policy. My experience in transmission includes power flow studies, generator interconnection studies, transmission service requests, interface transfer analysis, regional planning, industry committee participation, development and implementation of Southern Companies' Attachment K of its Open Access Transmission Tariff and administration of Southern Companies' generator interconnection process as related to the Large Generator Interconnection Procedures/Small Generator Interconnection Procedures. In addition, I not only served on the team that assisted in developing/implementing the Eastern Interconnection Planning Collaborative ("EIPC"), but I

also served on the team that developed/prepared the bid proposed and accepted by the DOE under FOA 0000068, Topic A (Interconnection Level Analysis and Planning for the Eastern Interconnection). I currently serve as chairman of the Steady-State Modeling and Load Flow Working Group, responsible for the transmission analysis and load flow model development associated with the cooperative agreement awarded by the DOE.

2. I believe certain factual assumptions and preliminary findings set forth in the Commission's Notice of Proposed Rulemaking on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities in Docket No. RM10-23-000 ("NOPR") are incorrect as a general matter, and are certainly incorrect to the extent the Commission assumes that they are consistent with or representative of the transmission system and transmission planning processes (and the results of those processes) in the Southeast. This affidavit is intended to provide additional information that the Commission can use to better evaluate the impacts (primarily detrimental) of the NOPR's proposals on transmission planning and the transmission system in the Southeast, as well as the NOPR's impacts on Southern Companies' State-mandated duty to reliably serve native load.[1]

3. In evaluating the impact of the NOPR's proposals, it is important to understand how transmission expansion is planned and executed in the Southeast. In the Southeast, generally, and for Southern Companies specifically, transmission planning begins with vertically integrated utilities' fulfillment of their legal duty to serve native load, which duty entails (in part) participation in State-regulated integrated resource planning ("IRP")[2] processes and associated

[1] For purposes of these comments, in discussing transmission planning practices in the Southeast, I do not include the FRCC, as it is relatively unique given its peninsular nature.

[2] Depending upon the context, for purposes of this affidavit, the term "IRP" can mean either the process of integrated resource planning or the resulting plan itself.

requests for proposals ("RFP") processes that select the resources to be included in the IRP. While these IRP and RFP processes may be less prevalent in other areas of the country, they have produced transmission systems (and planning regions) that have no significant congestion.[3]

4. The State-regulated IRP and RFP processes, combined with wholesale transmission customers' firm service commitments (which represent those customers' resource procurement decisions), cause transmission planning and construction in the Southeast to focus on meeting – in advance and in a least-cost manner – the identifiable, incremental firm needs of native load and wholesale transmission customers. Importantly, these processes ensure that *firm* needs are met; utilities in the Southeast do not plan for non-firm, speculative or hypothetical needs.

5. I understand that the NOPR proposes that each FERC-approved regional process shall consider and evaluate transmission facilities "and other non-transmission solutions that may be proposed" and develop a regional plan that identifies transmission facilities that "cost-effectively meet the needs of transmission providers, their customers and other stakeholders."[4] The transmission planning processes conducted in the Southeast are not, however, *resource* planning processes. Rather, *resource* planning for Southern Companies is conducted through State-regulated IRP and RFP processes, and wholesale transmission customers are expected to make their own least-cost resource planning decisions. Those customers' transmission needs to accommodate their procurement decisions are reflected in the long-term firm transmission service reservations that they make. However, it is my understanding that Southern Companies

---

[3] *See, e.g.*, Department of Energy 2009 Transmission Congestion Study, p. 61 ("Because the southeastern utilities build aggressively in advance of load, there is little economic or reliability congestion within the region"; *see also* NOPR, P 34 (discussing congestion issues within PJM).

[4] NOPR, P 51.

explained in their most recent Attachment K compliance filing that their transmission planning processes are not resource planning processes and that "non-transmission solutions" are only considered in the transmission planning context, and the Commission accepted that filing.

6. For purpose of my affidavit, the term "regional" means the region defined as the Southeast Regional Transmission Planning Process ("SERTP") planning region. I use the term "inter-regional" to mean any coordination or facilities between the SERTP and utility(ies) or regions adjacent to the SERTP (such as coordination through the Southeast Inter-regional Participation Process ("SIRPP"), coordination conducted through SERC-wide reliability processes, and coordination that results from the Southern Companies-FRCC planning efforts).

I. <u>Overview of Southern Companies' Transmission Planning Process</u>.

7. At the outset, it is important to reiterate that transmission planning is not resource planning. Resource planning includes an assessment of projected load requirements and the potential generation and demand-side resource options that can meet the forecasted demand. Resource planning requires extensive cost assumptions regarding resource options, future fuel forecasts, environmental costs, and other parameters. Resource decisions and load requirements are data *inputs* to the transmission planning process. Transmission planners support the resource planning process by providing assessments of the transmission needs and costs associated with various resource options, but the cost analysis of non-transmission, demand side, and supply side options and ultimate resource decisions are made by resource planners (*e.g.*, a Load Serving Entity ("LSE")), not the transmission planner. As such, non-transmission resource and load decisions (whether for native load or for wholesale customers under the OATT) become inputs to the transmission planning process.

8. Simply stated, the transmission planning process has three primary goals:

a. Plan expansion of the transmission system to accommodate future native load growth (a goal driven by vertically integrated utilities' legal duty to serve native load and carried out through State-regulated IRP processes).

b. Plan expansion of the transmission system (as necessary) to integrate new resources that have been selected through State-sponsored IRP processes or otherwise approved by the respective State Public Service Commission ("PSC") and designated by the LSE.

c. Plan expansion of the transmission system (as necessary) to accommodate long term firm transmission service procured as part of the OATT.

9. The expansion plan produced to achieve these three (3) goals is a ten (10) year plan. As part of an annual cycle, this plan is updated as planned transmission facilities are added/removed or re-timed throughout the course that year. However as assumptions/inputs change over the course of that year, the ten year expansion plan is modified accordingly (because transmission plans are dynamic and iterative in nature). At the completion of each annual cycle, the process begins again.

II. Annual Transmission Planning Cycle

10. Because transmission planning does not begin in a vacuum (*i.e.*, the existing transmission system is already in operation), the "from scratch" starting point for each annual planning cycle is the most recently developed Eastern Interconnection Reliability Assessment Group ("ERAG") Multiregional Modeling Working Group ("MMWG") base cases which provide the latest compiled information on the electrical topography of the eastern interconnection. All Planning Authorities ("PA") participate in the development of these cases. However, upon receipt of the cases, it is likely that changes have occurred on each PA's system,

and each PA will update its assumptions/inputs accordingly. As a result, the annual update cycle begins with each PA's receipt of the MMWG base case from the prior year and updates to that base case to reflect changed circumstances and updated assumptions. At this point, each PA becomes the "bottom" of the "bottom-up" planning process that will culminate in producing the new ERAG MMWG base cases (and, along the way, local and regional plans). All stakeholders have the opportunity for input into assumptions, methodology and subsequent findings of Southern Companies' portion of this bottom-up process as outlined in Attachment K to Southern Companies' OATT.

11. Each of Southern Companies' individual franchised public utilities (*i.e.*, Alabama Power Company, Georgia Power Company, Gulf Power Company and Mississippi Power Company) provides updates to expected native load and load growth for the ten year plan (which updates are developed through their IRP processes). These updates include energy efficiency impacts and also reductions in expected load due to non-dispatchable (passive) demand side management resources ("DSM"). Updated load assumptions include projections in load and load growth associated with network service reserved under the Southern Companies' OATT.

12. Each operating company also updates its resource assumptions (which updates are also developed through their IRP processes). As previously mentioned, new resources may have been selected as part of a State-sponsored RFP and/or approved by the appropriate State PSC, and have become network resources. In the case of some future years that are further out in the plan, the resources identified by the operating companies may reflect "best guess" projections of future resource locations and characteristics. As resource needs becomes definitive (usually within 3 to 5 years of the expected need), Southern Companies' franchised public utilities utilize their State-regulated procurement processes (*i.e.*, the RFP and/or IRP processes) to procure the

most reliable, least-cost resources. Included in the operating companies' determinations of resource needs are dispatchable (active) DSM considerations and other commercially available non-transmission options; but, again, those determinations are made by resource planners, not transmission planners. Wholesale network service customers also provide resource assumptions in accordance with the OATT.

13. Next, any new long-term firm transmission service commitments undertaken under the OATT are included. This includes any adjustments to the specific resources and the affected interchange necessary to accommodate the firm commitment.

14. Southern Companies' transmission planners will then analyze the transmission system in order to determine if the currently planned projects and their associated timing are adequate to meet the firm transmission service commitments identified. Projects will be added/removed/re-timed as necessary to ensure reliable delivery of firm commitments. This analysis is performed in order to satisfy the planning criteria of the Southern Companies and the applicable NERC reliability standards.

15. As part of this analysis, the transmission planners proactively consider not only impacts to Southern Companies, but also to any adjacent PAs through the various coordination vehicles available. These vehicles include bilateral reliability agreements, SERC study groups that encompass the entire SERC Reliability Region to analyze simultaneous feasibility, and the various regional planning processes under Order No. 890. If these studies/analyses indicate that efficiencies in meeting firm commitments on a concurrent basis may be gained by further coordination between adjoining PAs, those PAs coordinate (as discussed below). It is my understanding that the results of these studies/analyses are then typically used by the respective

PAs to modify their expansion plans in order to eliminate or minimize/harmonize adverse impacts to other PAs or to implement any efficiencies discovered during the analyses. From this process, the Southern Companies' resulting ten-year plan is then incorporated into the next annual version of ERAG MMWG cases. At this point, the process is then repeated.

16. Transmission is necessarily constructed in "lumpy" installments – *i.e.*, transmission lines are generally fabricated only in certain limited ratings and thus, when installed, increase transmission capacity by a specific amount whether or not that entire amount is currently needed. Further, transmission that is planned to meet identified firm needs will necessarily be constructed to accommodate peak load, which often creates headroom at off-peak times. Because Southern Companies' current planning processes identify and construct necessary transmission to meet identified firm needs in advance, headroom capacity exists for opportunity purchases both within and without the transmission planning region. Therefore, when transmission is constructed in the Southeast in advance of need (in order to ensure that there is no congestion of firm service), customers receive the benefit of headroom capacity created by a system that is planned to meet peak load requirements and sometimes constructed in unavoidably lumpy installments. As a result, customers in the Southeast have ample opportunity and ability to make opportunity purchases or sales, if they so choose (in addition to making long-term purchases or sales, as described above).

17. In my opinion, which is based on my understanding of the NOPR, as informed by my familiarities with the Southern Companies, as well as my educational and professional experience, the proposed mandatory reforms set forth in the NOPR are likely to do more harm than good to transmission planning, construction and service in the Southeast generally and Southern Companies' service territories specifically.

III. <u>No Discrimination against Any Stakeholders, Including Non-Incumbents</u>

18. The NOPR characterizes the Order No. 890 processes as having "given customers and other stakeholders the opportunity to participate in the identification of *regional needs* and corresponding solutions, thereby facilitating the development of more efficient and effective transmission expansion plans…."[5] Stakeholders engage in the process in many ways, including through requests for interconnection and transmission service, participation in state IRP processes and RFP solicitations, designations of network resources and other activities. To date, these methods of engagement have been far more influential in developing efficient expansion plans than input from stakeholders in the SERTP and SIRPP.

19. If the NOPR intends "regional needs" to mean stakeholder desires for economic projects, the SERTP process articulates a procedure for stakeholders to propose (and have studied) up to five (5) economic sensitivities, free of charge. Not only may stakeholders propose up to five studies that may assist them in assessing various opportunities to meet such "regional needs," but stakeholders may also request "Additional Economic Planning Studies" at their own expense. If an economic upgrade is determined to be "needed" by stakeholders, then the cost allocation methodology in Attachment K lays out the process by which those stakeholders may cause the identified project(s) constructed and funded. To date, stakeholders have demonstrated no interest in pursuing upgrades identified in the requested economic sensitivities, and there have been no requests for additional economic studies.

20. In addition to the regional opportunities provided to address the aforementioned "regional needs," stakeholders are also given multiple opportunities per year to participate in the Southeast Inter-regional Participation Process ("SIRPP") sponsored by Southern Companies and

[5] CITE (emphasis added).

twelve (12) other utilities in the Southeast. The SIRPP provides stakeholders the opportunity to request inter-regional economic studies that cover a very broad inter-regional footprint. To date, not a single alternative transmission solution has been proposed by stakeholders in the SIRPP as a result of these studies.

21. The NOPR states that FERC has seen increasing interest in transmission investment among non-incumbent transmission developers,[6] but that these transmission developers express concern about their treatment in relevant transmission planning processes.[7] The NOPR also states that "there appear to be opportunities for undue discrimination" against non-incumbent transmission developers within existing regional transmission planning processes.[8] Further, the NOPR claims that non-incumbent transmission developers may be less likely to participate in the regional processes because these processes do not consider and evaluate projects proposed by the non-incumbents.[9]

22. I am aware of no instance where non-incumbent transmission developers have complained that the SERTP unduly discriminates against them or that their projects have not been included in the existing SERTP planning process. In fact, no non-incumbent transmission developers have even indicated an interest in participating in the SERTP. However, if a non-incumbent were to participate in the SERTP and propose an alternative transmission project, then that proposal could and would be evaluated pursuant to the SERTP planning process. Moreover, there are no opportunities to discriminate against any stakeholder in the SERTP, as it is an open and transparent planning process. Any stakeholder would know whether its proposed project

[6] I refer to merchant and non-incumbent transmission providers as "non-incumbents."

[7] NOPR, P 38.

[8] NOPR, P 87.

[9] NOPR, P 88.

had been discriminated against during the planning process. Further, none of the transmission providers in the SERTP have a right of first refusal to construct new transmission facilities. As a result, the NOPR's concern about undue discrimination against non-incumbent transmission developers with respect to the SERTP process is unfounded. The same can be said of the SIRPP.

23. Southern Companies have worked directly with merchant transmission developers regarding requests to create new points of interchange via high voltage, long distance DC lines. To the extent such proposals prove economically viable, cost recovery can readily be accomplished by the developer through an appropriate tolling rate for usage of the facility.

IV. Existing Processes Are Sufficient

A. Existing Regional Planning Processes Are Sufficient for Regional Analysis

24. The NOPR states that:

> Order No. 890's regional participation principle may not be sufficient, in and of itself, to ensure an open, transparent, inclusive, and comprehensive regional transmission planning process. Without such a process, each transmission provider will not have information needed to assess proposed projects and determine which project or group of projects could satisfy local and regional needs more efficiently and cost-effectively. As a result, the rates, terms and conditions of transmission services may not be just and reasonable....[10]

25. The NOPR's assertion that "each transmission provider" currently does not have sufficient information to assess proposed regional projects and to determine whether a project or group of projects could satisfy local and regional needs more efficiently and cost-effectively is incorrect, at least to the extent that "each transmission provider" includes those in the Southeast. The Southeastern transmission owners collaborate through the SERTP, SIRPP, and SERC-wide

[10] NOPR, P 49.

data sharing and long-term study group activities as well as various bilateral agreements that allow assessments of any and all proposed projects in order to determine whether those projects satisfy local and regional needs.

26. To further illustrate this point, the SERC-wide reliability assessments that are performed on an annual basis provide additional data exchange and study coordination between PAs in order to consider and evaluate the potential impacts of the expansion plans of each PA adjacent to the Southern Companies. This process not only provides an excellent forum for information sharing, but also results in proactive assessments that are used as indicators for potential joint studies that may need to be conducted. While SERC itself does not perform any transmission planning, it provides a structure through which the PAs in the Southeast integrate their individual transmission plans to make the SERC-wide transmission base case every year. Existing bilateral reliability agreements are the primary vehicle that allows adjacent transmission owners/PAs the ability to study and assess the reliability impacts on the other (potentially impacted) systems. Whether a joint study is the result of the SERC-wide assessment or a result of other assessment activity, if joint projects or changes in the existing expansion plans are shown to be more effective and efficient for the respective customers of each PA, then the expansion plan will be adjusted as part of the annual planning cycle. As the expansion plan is adjusted, it is then brought to each PA's respective regional planning process for stakeholder input. If stakeholders identify alternatives to the proposed project, then the respective PAs would consider their proposals, compare those proposals against the existing proposal created by the PAs and report back the results to the stakeholders. While these mechanisms identify the most efficient and cost effective transmission solution, stakeholders have the opportunity to further communicate and coordinate with PAs through the economic sensitivities of the SERTP

and SIRPP. Should these additional opportunities show transmission upgrades of interest to any stakeholder (including the PA or LSE), then the necessary processes are already in place to pursue upgrades or enhancements.

27. The NOPR does not identify what specific information (or even which types of specific information) might be unavailable to transmission providers and/or to regional planning processes. Thus, I believe it is difficult to address whether that information is, in fact, unavailable. It is even more difficult for me to discern whether the supposedly unavailable information (or types of information) would or could enhance a regional planning process or could be provided/obtained under existing processes.

28. Despite the difficulties of discerning the predicate for the NOPR's assertion about unavailable information, I can say that, based upon my education and experiences, including those as a transmission planner, that the transmission providers in the Southeast responsible for transmission planning possess and exchange all information necessary "to assess proposed projects and to determine which project or group of projects could satisfy local and regional needs more efficiently and cost effectively."

29. Although Order No. 890 and Attachment K created formal procedures for regional transmission planning, regional planning and regional coordination existed long before the introduction of Order No. 890. In fact, as previously described, PAs in the Southeast have historically engaged in coordinated regional planning through the SERC-wide reliability assessment process and also through bilateral reliability agreements that have resulted in numerous *ad hoc* joint reliability studies. As a result of the pre-existing regional coordination and information exchange processes (which have only been expanded upon by Order No. 890),

the transmission system in the Southeast meets local and regional needs efficiently and cost-effectively.

B. Existing Processes Are Sufficient for Inter-Regional Analysis

Existing Processes Are Sufficient

30. The NOPR states that "there are few processes in place to analyze whether alternative interregional solutions would more efficiently or effectively meet the needs identified in individual regional transmission plans"[11] and then speculates "that the lack of coordinated transmission planning processes across the seams of neighboring transmission planning regions could be needlessly increasing costs for customers."[12] The NOPR assumes that current planning processes not only do not evaluate interregional opportunities (*e.g.*, do not canvass resource alternatives outside of their planning region), but also that current processes somehow *cannot* do so. These statements also suggest to me an assumption that transmission planning processes that do not or may not assess the import of remote resources from outside of the planning region (absent a specific transmission service or study request): (A) increase either (i) transmission rates or (ii) the delivered price of energy; and (B) potentially eliminate purchase and sale opportunities for their native load and/or wholesale transmission customers. None of these assumptions are correct in the Southeast. These statements also indicate a misunderstanding of how the bulk power transmission system in the Southeast is studied and expanded to meet customer needs (*i.e.*, firm transmission service commitments) in a reliable and cost-effective manner so that costs for native load and wholesale customers are not needlessly increased.

---

[11] *Id.*, P 103.

[12] *Id.*, P 113 (emphasis added).

31. When there is a *bona fide* need to construct significant inter-regional transmission facilities to serve firm native load commitments on a reliable, least-cost basis in the Southeast, the current transmission planning processes in the Southeast are sufficient to identify that need and support the pursuit of construction. State-regulated IRP and RFP processes evaluate inter-regional opportunities by canvassing resources that are out-of-State, outside the SERTP transmission planning region and outside the Southeast. The Southern Companies' IRP processes are committed – and, in fact, are legally required – to meet identified native load needs on a reliable, cost-effective basis. Therefore, if a remote but viable resource alternative would meet the needs in a reliable, least-cost manner, then the IRP and RFP processes would ensure that transmission facilities are planned, constructed and funded to access that resource. In addition, if any transmission facilities were required outside of the Southern Companies or SERTP footprint, then Southern Companies would use existing OATT processes or bilateral reliability agreements to ensure those facilities are constructed.

32. If remote generation resources are identified as the reliable, least-cost alternative through the State-regulated IRP/RFP processes (or if interregional purchases or sales are identified through third-party decisions leading to firm transmission service reservations on Southern Companies' system), Southern Companies are obligated to plan and construct the transmission facilities on their systems necessary to access those resources. Moreover, if the distantly located resources are chosen through the IRP or RFP processes, the native load customers of Southern Companies will pay for any necessary transmission service (or expansion) on other systems in other regions to access the identified resources either (1) through the direct purchase of such service by the Southeastern utility if it is responsible for delivery of the power to its service territory, or (2) by requiring the seller to arrange for such transmission service (and

include it in the price of delivered power) if the seller is responsible for delivery under the governing supply agreement. In either case, the cost of transmission service would be factored into the economic evaluation of resources competing to meet the need identified in the IRP process. Long-term firm transmission service under the OATT has proven to be an excellent means to assure cost-effective delivery, providing the level of certainty necessary to support long-term bilateral contracts to access distant resource options. LSEs both within Southern and outside the region have long utilized and continue to utilize transmission service under the OATT to access economic resources in other States and regions.

33. As previously described, Southern Companies' native load resource decisions are actively overseen and approved by State regulators through either an RFP process or some similar process. These decisions and processes include transmission evaluations either at the regional or inter-regional level. Once supply resource issues are decided and included as data inputs into the plan, the required coordination with neighboring PAs begins. The SERC-wide reliability assessments and bilateral reliability agreements discussed above in the context of regional transmission planning are also used to assist in inter-regional planning (as discussed below) because the SERC-wide processes cover an inter-regional footprint.

34. The NOPR finds that "in the absence of coordination between transmission planning regions, transmission providers may not identify more efficient and cost-effective solutions to the individual needs identified in their respective utility-level and regional transmission planning processes, potentially including interregional transmission projects."[13]

---

[13] *Id.*, P 39.

This is counterfactual in the Southeast. To understand the error in this statement, one must consider how the "identification of inter-regional solutions" is implemented in the Southeast.

35. In the Southeast, most transmission expansion occurs close to load centers, which are not necessarily close to a PA's boundaries (*i.e.*, the seam between PAs). If a load center is located close to a seam, or if upgrades/additions to existing facilities near a seam prove to be necessary, then coordination with the neighboring PA will occur as a result of good utility practice, through bilateral reliability agreements or as the result of potential issues identified in the SERC-wide reliability assessments. If it appears as part of the coordination that an alternative solution to the initial one posed may more effectively and efficiently meet the identified customer needs (*i.e.*, serve the identified firm transmission commitments) of each PA, then that solution would be evaluated by those PAs. Should the additional analysis confirm that "coordinated" facilities crossing from one PA to another PA (and therefore likely from one State to another State) are more efficient and cost-effective for meeting the firm transmission commitments of each PA than the facilities contained in each component plan, it is a prudence imperative that the more efficient/cost-effective project would be planned and move forward to completion (subject to the same hurdles faced when siting facilities within the boundaries of an individual PA).

36. Even if renewable portfolio standard ("RPS") initiatives are adopted in or for the Southeastern States, utilities in the region (including Southern Companies) expect that the least-cost, most reliable means of satisfying renewable and alternative energy requirements will generally be to utilize regional resources – *i.e.*, *not* to construct interregional facilities to obtain access to Midwest wind or Western solar/geothermal resources. As examples of the low carbon resources available within the region (*i.e.*, accessible with minimal transmission expansion and

associated costs), the Southeast is pursuing locally available new nuclear, integrated gasification combined cycle with carbon capture, biomass, and (to the extent feasible) solar generation resources. Very few (if any) of these locally available resources will require the construction of significant interregional transmission facilities.

37. Of course, assuming that no significant transmission expansion is necessary, a modest level of wind imports may be economically viable when coupled with predictable cost and reliable delivery service under existing OATTs. In fact, Southern Companies have active requests for long-term firm service pending with SPP, which Southern Companies would use to support long-term bilateral purchases from wind resources if they prove economically viable (*e.g.*, if no significant transmission expansion is required to access them).

Inter-Regional Agreements Will Not Assist Construction of Inter-Regional Facilities

38. If the Commission finds (contrary to the intention of the SERTP regional participants) that the "region" for the Southeast encompasses the entire SIRPP, then the concept of multi-lateral inter-regional agreements becomes both redundant and particularly problematic. As described by the Commission, these inter-regional agreements would primarily be focused on a more formal data exchange process and a more formal process for identifying projects on seams. However, proactive analysis of inter-regional facilities through existing bilateral agreements and long standing study practices of SERC member PAs exists today. In fact, such analysis is required by NERC Reliability Standard TPL-5. For projects to be identified on the outer borders of the SIRPP members, it is up to the individual SIRPP member PA on the relevant outer seam to implement the project, and processes already exist to address such scenarios. Currently, existing seams analysis and any resulting improvements (whether performed

collectively or by individual PAs working together) become an input into each existing regional planning process. Stakeholders have the opportunity at that point to propose additional solutions, new solutions, etc.

39. In light of the foregoing, I do not believe that any Commission finding (whether preliminary or not) that the SERTP or Southeastern planning processes are (or may be) "failing to analyze whether alternative interregional solutions would more efficiently or effectively meet the needs identified in individual regional transmission plans," or are "needlessly increasing costs for customers," would be correct. Any perceived lack of interregional facilities in the Southeast does not indicate a failure of the planning processes to analyze such facilities, but instead a failure of those facilities to be worth the cost.

40. The NOPR additionally states that the "availability of federal funds to pursue interconnection-wide transmission planning has increased awareness of the potential for greater coordination among regions in transmission planning."[14] It is not correct to assume that a perceived lack of interregional facilities means that the current planning processes do not evaluate them, or that transmission planners have only recently been "made aware" of their potential as a result of the American Recovery and Reinvestment Act ("ARRA")-funded processes. As an active participant in the ARRA-funded Eastern Interconnection Planning Collaborative ("EIPC") process, I can attest that although such facilities are analyzed, they have yet to be identified as prudently meeting native load or wholesale transmission customer needs. Further, experience with the EIPC process shows that increased coordination among regions does not necessarily result in the identification of additional inter-regional facilities that could

[14] NOPR, P 112.

provide measurable customer benefits or that could meet any identifiable needs (particularly with respect to the Southeast). This indicates that the "failure" to identify interregional facilities that more efficiently and cost-effectively meet the needs of native load or other transmission customers is not a failure of the current transmission planning processes, but rather is a function of the relative (lack of) merit of such facilities.

V. NOPR Proposals Will Do More Harm than Good

A. Requiring a Formal Regional Plan Is "Top Down" Planning

41. The NOPR proposes to require transmission providers to "participate in a regional transmission planning process that produces a regional transmission plan" and that meets seven of the nine transmission planning principles established in Order No. 890.[15] More specifically, the NOPR proposes to require that "each regional transmission planning process consider and evaluate transmission facilities and other non-transmission solutions that may be proposed and develop a regional transmission plan that identifies the transmission facilities that cost-effectively meet the needs of transmission providers, their transmission customers, and other stakeholders."[16] The NOPR further states that without the requirement to develop a regional plan, "the construction of new transmission facilities could be inhibited."[17] Additionally, the NOPR states that in the absence of such a requirement, "the facilities best suited to meet the needs of a particular region may not be identified."[18]

---

[15] NOPR, P 50.

[16] *Id.*, P 51.

[17] *Id.*, P 35.

[18] *Id.*

42. I do not believe these NOPR findings are correct. As an initial matter, having a regional transmission plan will not ensure that proposed facilities are constructed. A transmission plan is developed to determine how to expand the transmission system to meet identifiable customer needs, that is, identifiable customer needs drive transmission expansion. To the extent a transmission plan meets customer needs, the facilities in that plan will be constructed. If those needs change or disappear, that transmission plan will be scrapped (*i.e.*, the transmission system will not be expanded in accordance with that plan), and a new plan will be developed to meet the changed needs. The existence of a transmission plan does not drive transmission construction. Rather, customer needs drive transmission construction, and transmission planning is simply a means to the end of meeting customer needs – it is not a driver of transmission expansion.

43. In addition, the regional planning process proposed by the NOPR, where any proposals can alter the underlying bottom-up transmission plans, is top-down planning. In my opinion, anything other than a knitting together of bottom-up plans at the regional level is *per se* "top-down" planning.

44. More importantly, top-down planning is not consistent with the State-regulated IRP and RFP processes in the Southeast, which are built to be bottom-up processes and which will be delayed and disrupted by any top-down process.

45. If the NOPR intends the proposed interregional agreements to establish interregional planning processes that could significantly alter underlying bottom-up regional plans, then the Commission should understand that such a proposal would compel "top-down" planning at the interregional level. That is, any planning decisions made at the interregional

level would of necessity be made on a scale larger than the local and regional planning processes, which would render such decisions *per se* "top down." Consequently, either decisions made at the interregional level are not intended to result in significant or material changes to the underlying regional transmission plans or else the NOPR is, in fact, seeking to impose "top down" planning.

46. As a result, the only reasonable interpretation of the NOPR is that significant and materially influential transmission planning decisions will be made solely during the bottom-up processes that combine to form the regional transmission plan contemplated by the NOPR. Thus, the NOPR's finding that interregional agreements may minimize the number of planning meetings in which stakeholders participate is incorrect. Based on my experience, that proposal will only add to the number of planning meetings for stakeholders to choose from, thereby increasing the "barrier" to meaningful stakeholder participation mentioned in the NOPR. Moreover, such a finding could be construed to imply that stakeholder participation in an interregional process can be a substitute for (or bypass of) participation in the underlying regional transmission planning processes. This is not the case (and could mislead stakeholders) because decisions at the interregional level cannot significantly impact transmission planning (as they would then be "top-down" planning decisions that supplant bottom-up planning decisions).

B. NOPR Proposals Will Impede the RFP/IRP Processes and Interfere with Implementation of the OATT

NOPR Proposals Will Harm IRP and RFP Processes

47. As described above, Southern Companies generally participate in State-sponsored, State-regulated RFP processes in connection with each State's IRP process. Timelines associated with the evaluation, selection, contracting and approval of resources are

short. In addition, the timing (issuance and implementation) of an RFP is not dependent on any regular schedule or tied to any annual cycle. RFPs are issued and implemented as resource needs are identified. As a result, the NOPR's proposal related to non-incumbents and their ability to sponsor projects in the "regional plan" could not only impede but harm the existing RFP processes.

48. First, there seems to be at least a theoretical possibility that transmission facilities required to integrate generation resources selected under a State-regulated RFP are subject to the NOPR's "sponsorship requirements."[19] If the NOPR intends to provide non-incumbents the right to sponsor transmission facilities identified as necessary in the IRP process, then the proposal that all potential sponsors of transmission facilities must submit proposals by a date certain[20] is either not feasible or else it dramatically impairs the RFP/IRP processes by requiring those processes to coincide with the deadline.

49. Second, even if a Final Rule is crafted to prevent non-incumbents from sponsoring projects necessary for implementation of the IRP/RFP results, the NOPR's sponsorship proposal would nonetheless adversely impact the RFP process. The best explanation is a hypothetical example. Consider the situation in which an RFP evaluation produced a least-cost resource for native load customers. Included in that evaluation/decision making process was the cost of the transmission facilities necessary to integrate the resource. If a non-incumbent transmission developer were to propose a project that was subsequently included in the "regional plan" (or an inter-regional plan), that project could change the system topography on which the RFP decision was based and ultimately increase costs to native load

[19] *Id.*, P 93.

[20] *Id.*, P 91.

customers and frustrate the purpose of the RFP process. In fact, in the effort to provide a process that is open and non-discriminatory for the non-incumbent transmission developer, inclusion of the non-incumbent transmission facility in the "regional plan" may actually harm generators bidding into an RFP. If the non-incumbent transmission facility had been assumed to be in place during the RFP, then a different generator may have won the RFP and the opportunity to enter into a power purchase agreement ("PPA").

50. Although not all potential conflicts, issues and impediments related to non-incumbents and the RFP process have been explored, one additional observation that can be made is the impact of potential disputes or litigation over rights to sponsor or build. Should any of the non-incumbent transmission facilities previously discussed be subject to dispute resolution or litigation, the RFP process would be crippled by the uncertainty as to which transmission facilities will be constructed (and modeled in the IRP/RFP process) and when. The delay in finalizing expansion plans due to disputes could (and would) hold the IRP and RFP processes hostage, thus delaying/preventing resource procurement and transmission expansion to serve native load customers.

The Proposed Reforms Will Impair OATT Construction and Service Processes

51. The Southern Companies' OATT provides for various transmission services, including point-to-point and network integration transmission service, as well as generator interconnection service. The evaluation processes associated with applications for these services are prescribed by the OATT (*e.g.*, system impact studies must be completed within 60 days).[21] Although unclear, it appears that the NOPR would limit the timeframe during which new

[21] *See, e.g.*, Southern Companies OATT, § 19.3.

transmission facility construction could be submitted into (and therefore included in) the planning process to one specific day per year. As transmission providers are required to study service requests and offer service based on time-lines prescribed by the OATT, it is difficult to reconcile how the "single date" requirement could be implemented in a manner that permits compliance with those timelines. The uncertainties created by the "single date" requirement could completely disrupt the transmission study processes required by the OATT and could impair the provision of any transmission service requiring construction of transmission facilities prior to commencement of the service. For example, system impact and facility studies for requests for long-term firm transmission service could not be completed (with any accuracy) until the elimination of uncertainty surrounding: (1) the eventual topography of the transmission system, which would be dependent upon proposed projects submitted on the "single date"; and (2) which entity would sponsor and construct any new facilities required to provide the service (which would likely impact the terms and conditions of the eventual service agreement). Moreover, these same uncertainties would have an even greater impact on the ability of a transmission provider to construct any facilities needed to provide firm OATT service, as the "single date" would: (a) impact decisions regarding what expansion might be needed; and (b) determine which entities would construct that expansion. As a result, the NOPR's "single date" proposal would not only interfere with and delay transmission construction, but they would also interfere with transmission providers' ability to meet the study timeline and metrics requirements imposed by Order No. 890.

52. It also appears that any transmission facilities identified as necessary to accommodate and provide requested OATT service would be subject to the provisions requiring that project sponsors have the right to construct new facilities that are "similar to" their proposals

and to retain that right for multiple planning cycles.[22] As a result, uncertainty would surround the execution of transmission service agreements and the pricing of transmission service because it would be unclear at the time of execution what transmission facilities might be necessary to provide service under the agreement.

53. In summation, the NOPR's proposals related to non-incumbent sponsorship of new transmission facilities appear to impair the OATT process and the responsibilities placed upon the transmission provider. Therefore, the Commission's proposal would actually impede the existing OATT processes.

C. NOPR Proposals Will Impair Southern Companies' Ability to Meet Their Service Commitments

NOPR Will Harm Ability to Meet Native Load Service Commitments

54. When supply resources are evaluated by Southern Companies (under State regulatory oversight) during an RFP, any transmission facilities required for firm delivery of the generation resource are identified (if any are necessary). Once the successful candidate of the RFP is approved by the State regulator, the resource is designated as a network resource. At that time, any required transmission facilities identified as necessary would be constructed and paid for by native load ratepayers. It is unclear whether transmission facilities identified in this process would be subject to the non-incumbent sponsorship provisions described in the NOPR. Should these facilities be subject to the non-incumbent sponsorship provisions, native load service could be harmed. Should strangers to the state utility regulatory compact, with no statutory duty to serve retail or native load consumers, have the opportunity to construct and own the transmission facilities necessary to integrate a native load resource, the native load customer

[22] *Id.*, PP 94-95.

could then become dependent upon the third party to have the facilities in place by the required service date. In over ten years of transmission experience, to the best of my knowledge, Southern Companies have not missed an in-service date for native load resource integration. A proven track record has shown that this incumbent can have the necessary facilities in place as required. Should a non-incumbent miss any required in-service milestones, native load customers could be harmed as generation curtailments would be likely, thus driving up generation costs unnecessarily (increasing the cost to the consumer unnecessarily) and impairing reliability. Further, it is unclear whether the State Public Service Commission could (or would) hold a non-incumbent accountable for any impacts of their failure to build or construction delays on service to native load customers. Such a situation could either leave native load customers entirely exposed to the risks associated with non-incumbent transmission, or else put vertically integrated utilities' shareholders at risk if they are required to "pick up the slack."

55. However, if it is assumed that non-incumbents may not sponsor projects identified as required in the IRP and RFP processes, they may still decrease the quality of service and increase costs to native load customers relying on the resource that was selected as the least cost option during the RFP. To illustrate this point, assume that a resource has been chosen pursuant to an RFP and the transmission facilities required to integrate the resource have been identified, budgeted, approved as prudent, and planned for construction. Also assume that as part of the "regional plan" proposals described in the NOPR, a non-incumbent subsequently proposes a transmission project and is included in a "regional plan." The addition of the non-incumbent's subsequently planned transmission facility could negatively impact the quality (and economy) of service previously planned for the native load resource. If any additional transmission facilities required to maintain quality of service to native load customers could be constructed and the

costs allocated appropriately (*i.e.*, to the non-incumbent who has interfered with native load service), then this risk is somewhat minimized. However, to the extent that subsequent expansion plans begin to take into account the not-yet-constructed non-incumbent transmission facility, and the surrounding grid is planned and constructed in a manner such that it is "dependent" upon the non-incumbent facility, the potential harm to native load is once again increased. If the non-incumbent's construction is delayed, or other unexpected changes occur (*e.g.*, non-incumbent bankruptcy), native load service could become subject to *pro rata* curtailments that could result in higher costs and impaired reliability for the native load customer.

56. System needs can change (*e.g.*, another recession leads to revised load growth projections) such that a non-incumbent's proposed project included in the transmission plan would be delayed or no longer needed. If the system were planned in a sub-optimal manner in order to construct a non-incumbent project that should be delayed or scrapped due to changed needs, such sub-optimal planning would increase costs to native load customers (and, in extreme circumstances, could increase the risk of electrical outages or curtailments to native load and other firm commitments).

The NOPR Will Impair the Ability to Meet OATT Service Commitments

57. Per the Southern Companies' OATT, transmission service is studied and offered, in most cases, after about two to three months of transmission impact studies. In cases where transmission service offered is dependent on transmission facilities that are expected to be in service due to other drivers/requests or is dependent on new facilities identified expressly for the requested service, the transmission service provider is contractually obligated to provide the

service once the Transmission Service Agreement ("TSA") is in place. Should non-incumbents have the opportunity to sponsor and construct facilities necessary to provide the transmission service, the transmission customer and the transmission service provider then become dependent upon the third party to have the facilities in place by the required service date. Not only does this become a liability issue for the transmission service provider, but it also becomes a potential cost burden to OATT customers whose service is premised on the non-incumbent's facilities being constructed in time. Similar to the native load argument outlined above, OATT customers could be harmed as generation curtailments would be likely, thus driving up generation costs unnecessarily (increasing the cost to the consumer unnecessarily) and potentially impairing transmission service and reliability.

D. NOPR Proposals Will Harm Reliability

58. As noted above, the NOPR's proposed planning and cost allocation requirements would seriously undermine the Southeastern planning processes and thereby make it more difficult to move forward with new transmission projects. The NOPR' proposals run counter to promoting a LSE's ability to meet its native load service obligations (at least in the Southeast), and in my opinion, if made requirements, would diminish the ability of Southern Companies to expand the transmission system to serve their native load. The NOPR's proposals will also likely add costs, delay, uncertainty and bureaucracy with little or no benefit to transmission planning in the Southeast.

59. In addition, I believe the NOPR's non-incumbent-related proposals could jeopardize system reliability. Examples of potential impacts to reliability that I see include:

a. If a non-incumbent were to discontinue a project included in a regional plan too late for the regulated incumbent transmission owner and operator to recover in a timely fashion, such abandonment would expose the incumbent transmission owner to reliability standard compliance issues (which would potentially require the transmission provider to put short-term mitigation procedures in place in order to remain compliant, thus potentially increasing costs for native load customers).

b. If a non-incumbent were to enter into bankruptcy status and leave the operation and maintenance of its facility in a state of confusion (and/or abandon a planned facility in an incomplete state), such bankruptcy would increase the risk of electrical outages or curtailments to native load and other firm commitments.

c. If a non-incumbent were to fail to make needed improvements to its facilities (whether or not such improvements were identified through the regional planning process), such failure would increase the risk of electrical outages or curtailments to native load and other firm commitments.

Further affiant sayeth not.

This 28 day of September, 2010.

Bryan K. Hill

Bryan K. Hill

Sworn to and subscribed before me this 28 day of September, 2010, by Bryan K. Hill, who is personally known to me.

Esther T. Howard

Notary Public
My Commission Expires On

MY COMMISSION EXPIRES 05/16/2012

ESTHER T. HOWARD ★ NOTARY PUBLIC ★ ALABAMA STATE AT LARGE

ATTACHMENT B-2

EXPERT TESTIMONY OF GARY C. ROZIER

Originally Included as “Attachment B” to Southern Companies’ Initial Comments and “Exhibit 3” to Southern Companies’ Request for Rehearing

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation	)	Docket No. RM10-23-000
by Transmission Owning and Operating	)	
Public Utilities	)	

AFFIDAVIT OF GAREY C. ROZIER

I, Garey C. Rozier ("Affiant"), being duly sworn, depose and state as follows:

1. I am employed by Southern Company Services, Inc. ("SCS"), 600 North 18th Street, Birmingham, Alabama 35291 in the Resource Planning group as Manager of Resource Planning. I have been employed with Southern Companies (Georgia Power Company and SCS) since 1969. I graduated from Auburn University in 1972 with a Degree in Industrial Engineering and from Georgia State University in 1982 with a Masters of Business Administration. I have over 40 years of experience with Georgia Power Company and SCS in the areas of transmission planning, resource planning, power procurement and power contracts, and wholesale power marketing. I have broad experience in electric industry policy and planning activities including serving terms as Vice Chair and Chair of the SERC Planning Committee, Vice Chair and Chair of the NERC Planning Committee, and Vice Chair and Chair of the Edison Electric Institute Transmission Subject Area Committee.

2. My current job responsibilities include managing the development and coordination of the system-wide integrated resource plan and overseeing the system planning process on behalf of the Southern Company operating companies: Alabama Power Company, Georgia Power Company, Gulf Power Company and Mississippi Power Company (collectively,

"Southern Companies" and individually a "Company"). Each of these four retail operating companies conducts integrated resource planning pursuant to State-regulated processes to ensure that it maintains reliable service to its native load and requirements customers at the lowest feasible cost while complying with State-jurisdictional and federal mandates with respect to planning procedures and public policy. In implementing the integrated resource planning processes, I also provide support to the operating companies in the procurement of specific generating resources to fill supply needs identified in their resource plans. State regulatory oversight is carried out by the respective State Public Service Commissions ("PSC"), and this oversight includes review and approval of the integrated resource plan ("IRP") and granting certificates of convenience and necessity for new resources (both supply-side and demand-side).

3. Integrated resource planning is the process used to identify and plan for meeting native load and requirements customers' needs for electricity. Southern Companies' IRP processes consider a broad range of supply-side and demand-side options in a balanced manner to ensure reliability, to minimize costs in order to minimize rate impact, and to address key uncertainties faced by each Company. The primary objective of an IRP process is to secure the lowest cost electricity supply consistent with the quantity and quality of electric service desired by native load consumers. Given the integral role of the transmission system in delivering electric power from generators to customers, the integration of transmission and generation planning is a critical part of the native load planning process. State statutes and PSC rules provide a framework for this process and ensure that State and federal public policy objectives, customer feedback and customer impacts are considered and addressed in the IRP process (*e.g.*, environmental standards, the use of renewable sources, fuel source diversity, State economic impacts, customer rate impacts, federal emission regulations and energy efficiency). While each

one of the four retail operating companies is individually responsible for development of its IRP consistent with its State jurisdictional guidance, those companies coordinate the develop of their IRPs on a system-wide basis in order to achieve the additional benefits of operating their generation, transmission, and demand side resources as a tight power pool.

4. As State-regulated public utilities, the Southern Companies have an obligation to serve the full energy requirements of their retail customers in their franchised service territories as well as any full or partial requirements service to native load wholesale customers. Accordingly, all of Southern Companies' IRP planning efforts are focused on satisfying the obligation to provide reliable electric service at the lowest reasonable price to their customers. While an annual planning cycle is used for integrated resource planning and there are certain filings and approval requirements in each State jurisdiction, the planning for specific generation resources, demand side resources, and transmission facilities is an iterative, on-going process. Evaluation of resource options, commitments to specific resources to meet native load needs, and state PSC proceedings to approve the resources follows no specific schedule. Decisions and commitments to new facilities must be made throughout the year in order to reliably and economically serve load.

5. IRP planning is a comprehensive set of activities and processes that encompass both development and procurement of new resources as well as ensuring that existing resources are a part of an economic and reliable plan. The first component of the IRP process is to identify the need for additional resources. This process begins with the development of an individual retail operating company's energy and demand forecast. These projections are typically developed annually and updated during the year, as necessary. Such projections include an analysis of number of customers, territorial sales, territorial supply, demand response impacts

and peak demands. These forecasts form the basis of most subsequent planning for each Company and are also incorporated into the Southern Companies' system-wide coordinated planning process.

6. An important aspect of identifying the need for resources is to assess what portion of a Company's total load plus reserves can be met from the Company's existing generating units and controllable demand side resources. The Southern Companies maintain adequate generating reserves to mitigate the risks associated with weather uncertainties, load forecast uncertainties, and generating unit forced outages. These assessments are being made on a continuous basis as conditions change and new information becomes available. At least annually, the expected available generating capacity is compared to the load forecast to determine what additional needs, if any, the Company expects to have in the future. This comparison considers baseload and peak load requirements, fuel diversity, and other strategic considerations to characterize the expected need in both quantitative and qualitative terms.

7. If a Company determines that it will need additional resources to meet demand and reserve requirements, the next step is the identification of resource options that may be available to meet those needs. In this process, all feasible supply-side and demand-side alternatives are considered, using a marginal cost analysis – *i.e.*, least total electricity price for customers. This approach ensures that both supply-side and demand-side options are included in resource plans when it is economic to do so.

8. If the Commission is concerned that utilities that conduct integrated resource planning, such as Southern Companies, are not adequately considering regional and inter-regional generating resources due to a gap in the IRP processes, such a concern is unfounded.

First, it should be noted that power system economics, at least in my experience in the Southeast, generally favor sourcing from resources near the load. Southern Companies have conducted 16 Request for Proposals ("RFP") for long-term capacity since 1998. Over 13,000 MW of capacity has either been constructed or purchased through power purchase agreements resulting from solicitations during this period. All but one of these solicitations welcomed proposals from sources outside the Southern Companies transmission system (the exception being a solicitation requiring a generating resource to be located in the high-growth northeast Georgia area where additional generation would eliminate the need for a major transmission expansion, as identified in the state of Georgia IRP process). Although these RFPs have generally been widely distributed and announced in press releases and industry publications, very few bids were submitted from remote resources and only one off-system resource has as yet been determined (by Southern Companies and independently by the State PSCs) to be the least-cost option in a solicitation. In 2009, Mississippi Power Company accepted proposals from a number of generators outside of the planning region – *i.e.*, in the Entergy and TVA transmission systems – as part of a solicitation resulting from a Mississippi PSC order. Mississippi Power Company determined that transmission capability existed or could be constructed to support these sources; however, the Company determined that a self-build baseload project in Mississippi was economically superior. The Mississippi PSC, upon independent examination, concurred. Southern Companies' resource procurement experience demonstrates that: (1) extra-regional resources are canvassed under existing State planning processes; and (2) the State PSCs ensure that such processes achieve the best results for the native load customers of the integrated utilities; and (3) extra-regional resource options will only infrequently be the least cost choice of capacity and energy options available to meet forecasted customer demand in the Southeast.

9. To the extent that remotely located resources might prove to be economical, it is expected that they will generally be limited to circumstances where sufficient transmission capability already exists or can be created with a moderate expansion cost, since those resources requiring significant transmission construction would likely be priced out of market. Also, remotely located resources are at a disadvantage to locally sited resources due to transmission wheeling energy losses which typically average about 4% per wheel. Nevertheless, States in the Southeast already require vertically integrated utilities under their jurisdiction to evaluate *all* feasible demand and supply sources, and the State-regulated IRP and RFP processes *already* in place are adequate to explore and evaluate these options. The existing OATT service request processes in other regions are available to support transmission evaluations and implementation of any economical and practical off-system resources for Southern Companies (and other vertically integrated utilities with resource procurement duties). If load serving entities ("LSE") in the Southeast and their State regulators were to determine that access to substantial imports of distant resources such as wind power might be economical or necessary and consistent with public policy, the OATT and existing Attachment K processes already are sufficient to explore such alternatives.

10. In fact, Southern Companies have used third-party transmission providers' OATT processes to examine remote generation as a potential procurement option for integrated resource planning. For example, there is currently a great deal of interest in renewable power sources due to the potential federal mandate. Since the Southeast is very limited in cost-effective renewable supply options, inter-regional transport of wind power could be a component of compliance with any State or federal renewable portfolio standard. Through the existing OATT transmission service request processes, Southern Companies are initiating the necessary studies, both on-

system and off-system, to determine the transmission availability and cost for a competitive tier of power sale offers made to Alabama Power Company in its current renewable energy solicitation. This resource procurement assessment reflects the public policy interest of Alabama Power Company and its State PSC in exploring renewable energy options. If the economics of any of these off-system resources are favorable, the necessary coordination with other regional/interregional transmission providers can occur through their existing OATT and Attachment K planning processes.

11. When available resources are identified, a Company uses a generation screening and evaluation process to assess the comparative performance of the various resource alternatives available to meet the Company's generation needs. This evaluation considers expected future customer load growth, baseload and peak load requirements and fuel diversity; the Company also conducts a detailed evaluation of the various supply-side and demand-side technologies available to meet any additional capacity requirements. The relative costs of fuel, as well as the effect of State and federal environmental laws and regulations, are vital parts of the evaluation of supply alternatives. Importantly, any costs of transmission improvements (including the costs of any transmission improvements on the Southern Companies' transmission system or transmission service payments to third-party systems) necessary to implement each alternative must also be considered in this evaluation.

12. The Georgia IRP and RFP processes provide a useful example of how the State IRP processes work. The Georgia IRP statutes, O.C.G.A. 46-3A-1, *et seq.*, set in place a triennial IRP filing and a comprehensive process for PSC review and PSC certification of new generation and demand resources. Georgia Power Company's IRP filing must include:

- The Company's projected electric demand and energy forecast for at least 20 years;

- The Company's program for meeting the requirements shown in the forecast in an economical and reliable manner;
- The Company's analysis of all capacity resource options including both demand-side and supply-side options;
- The Company's assumptions and conclusions regarding the effect of each resource option on the future cost and reliability of electric service; and
- The Company's ten-year transmission expansion plan.

13. The IRP statutes also provide for a regulatory proceeding for the certification of new capacity resources prior to the utility commencing construction of a generating facility or entering into a purchased power agreement to meet an identified energy/capacity need. Specifically, the IRP statutes state in relevant part:

> The [State] Commission shall issue an order adopting a forecast of future Georgia retail electricity requirements and describing in what manner the prospective certificate relates to the IRP and either granting the requested certificate or denying the requested certificate and authorizing a specific alternative means of supplying the requirements found by the Commission to exist in the forecast.[1]

14. While the IRP – including the ten year transmission expansion plan – must be filed at least once every three years it must be updated if any major changes in assumptions are made in the intervening years.[2] The statute also requires that the IRP be updated whenever certification is requested for a new capacity resource.[3] Georgia has experienced strong growth since the inception of the statute in the early 1990's, and the IRP has often been updated more frequently then the triennial requirement. The Georgia PSC has enacted comprehensive IRP and RFP rules to prescribe how a utility must develop its IRP, file the IRP with the GPSC for

[1] O.C.G.A. 46-3A-5(b).

[2] O.C.G.A. 46-3A-3(a).

[3] *Id.*

approval, and select capacity resources to meet the identified needs.[4] These rules further define and set forth the RFP process that must be utilized for every block of new supply-side resource identified in the Integrated Resource Plan, with limited exceptions.

15. IRP supply-side resource procurement decisions seek to obtain reliable energy at the least <u>total</u> cost – *i.e.*, for generation resources, the cost of the energy plus the cost of transmission service/expansion required for delivery. Consequently, the expansion and modification of the transmission grid is a critical component of the IRP and resource procurement processes. But, not only is the *cost* of transmission important, but the *timing* of any necessary transmission expansion is important. A resource will not likely be selected, no matter how cheap its total costs are, if energy from it cannot be delivered in time to meet retail and native load energy needs. Thus, transmission planning and expansion (and the costs associated therewith) are often large factors in determining which generating resources are selected by a Company to meet its retail and native load energy needs.

16. For example, transmission costs associated with distantly located resources can – and usually do – prohibit the selection of those resources over nearer resources, even if the energy costs of nearer resources are more expensive. In Southern Companies' experience, constructing (or purchasing) generation that is close to load is generally the least-cost and most reliable supply-side option to meet resource procurement needs.

17. As a result, the Southern Companies' resource planning personnel (in their capacity as LSEs) work in an integrated fashion with transmission planners to provide important input into the development of transmission planning base case assumptions and to consider the

[4] *See* Ga. Comp. R. & Regs. 515-3-4.

transmission needs and costs in the evaluation of alternative generation and demand resources. This process ultimately results in timely decisions and commitments to resources that provide reliable service to their end use customers at the least practicable price.

18. To summarize this point, the State IRP processes ensure that retail and native load customer needs are identified, all feasible options to serve these needs reliably and economically are considered, and ultimately that resource commitments are made and approved by the State PSCs sufficiently in advance of the need so that the generation, transmission, and distribution infrastructure can be constructed and put into service on time.

19. Transmission plans and specific transmission projects developed as part of the IRP processes are focused on linking selected generators to native load in order to meet the identified needs of Southern Companies' native load customers as reflected in the demand and energy forecasts included in the IRP. This planning process ensures that customer loads are reliably and economically served and that the native load generation resources are reliably connected to these loads. Southern Companies' OATT transmission planning and transmission service processes overlay with these load-serving obligations to provide for transmission expansion to serve any OATT customer uses of the transmission grid. In addition to this planning to meet their native load and OATT customer obligations, Southern Companies coordinate with other Planning Authorities ("PA") through, among other things: bilateral interchange and reliability agreements, the Southeastern Regional Transmission Planning Process ("SERTP"), the Southeastern Inter-Regional Participation Process ("SIRPP"), SERC reliability assessments, and the Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group. Because these processes are bottom-up processes, they

do not disrupt the underlying State-regulated integrated resource planning of various vertically integrated transmission providers in the Southeast (including Southern Companies).

20. The NOPR expresses concern that public policy objectives are not adequately considered in the transmission planning process. This is clearly not true in the Southeast region. State and federal public policy with respect to the amount, timing, and type of demand and supply resources to serve end use customers is reflected in the IRP and RFP requirements and expectations of the States in which Southern Companies operate. The States have exclusive authority over and work with each regulated utility to ensure that all relevant public policy, as set by that State, is at the heart of the bottom-up integrated generation and transmission planning process. This responsibility for – and authority over – implementation/enforcement of public policy lies with the States. The Southern Companies' transmission planning functions do not, should not, and cannot identify and implement public policy as it relates to the amount, timing, and type of generation resources that should be utilized to meet Southern Companies' load serving obligations – and this lack of authority to identify and implement public policy extends to the transmission planning necessary to link those resources to load. In other words, Southern Companies cannot choose to implement public policy through transmission planning in a way that deviates from their State-regulated IRP and RFP processes. Therefore, the regional planning process proposed in the NOPR (which would require Southern Companies to implement public policy at a regional level) cannot coexist with their State-regulated IRP and RFP processes.

21. At least as it relates to the Southeast and other regions utilizing the vertically integrated utility model, the NOPR is mistaken when it states:

> When conducting planning to serve native load customers, a prudent transmission provider will not only plan to maintain reliability and consider whether transmission upgrades or other investments can reduce the overall costs of serving

> native load, but also consider how to enable compliance with relevant public policy requirements established by state or federal laws or regulations in a cost-effective manner. Therefore, we propose to find that, to avoid acting in an unduly discriminatory manner, a public utility transmission provider must consider these same needs on behalf of all of its customers.[5]
>
> Specifically, we propose to require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of public policy requirements established by state or federal laws or regulations that may drive transmission needs.[6]

22. There are three fundamental flaws in the NOPR's proposal to compel transmission planners, through the OATT and regional planning processes, to explicitly consider such public policy requirements.

23. First, the proposal seeks to merge Southern Companies' State-regulated obligations to perform resource planning for their retail and native load customers with their federal obligation to provide transmission service (*e.g.*, plan and construct their system to serve OATT firm commitments) on a non-discriminatory basis. However, these two obligations are very distinct in operation and require different skill sets and analyses. As State-regulated resource planners, each Company is obligated to determine its retail and native load obligations and acquire the resources (including transmission) necessary to serve that load *in compliance with public policy*. In other words, it is through resource procurement for their retail and native load customers – *not* through transmission planning – that Southern Companies comply with State and federal public policy. Resource procurement is not an activity in which Southern Companies can (or should) assist OATT customers, but it appears to be what the NOPR's proposal would require – *i.e.*, in order for Southern Companies to plan their system in order to

[5] NOPR, P 56.

[6] NOPR, P 64.

"enable [OATT customer] compliance with relevant public policy requirements established by state or federal laws or regulations in a cost-effective manner,"[7] Southern Companies would have to be intimately involved in those entities' resource procurement decisions. Further (as discussed below), Southern Companies' States actively regulate Southern Companies' resource procurement in order to ensure that State and federal public policy goals are met – *i.e.*, even in resource procurement, Southern Companies depend upon their States for direction in how to comply with federal and State public policy. Because Southern Companies do not perform resource procurement for OATT customers, they: (1) are not the entity responsible for compliance with State and federal public policy with respect to OATT customers (or their end consumers); (2) can only provide transmission planning and expansion to serve the firm transmission commitments made by those customers to implement their resource procurement; (3) cannot assist those customers in resource procurement decisions (which is how Southern Companies comply with public policy requirements); and (4) cannot best judge how to "cost-effectively" enable public policy compliance for those customers – particularly if the public policy at issue does not apply to Southern Companies. However, transmission planning can and does support OATT customers in meeting their policy requirements through providing timely responses to transmission service requests including full cost and schedule estimates.

24. Secondly, all State and federal laws and regulations that may drive transmission needs are already considered and incorporated in the demand and supply resource planning *and the associated transmission planning* that occurs in the bottom-up IRP and RFP processes described above. Such public policy requirements include compliance with the Clean Air Act requirements, PURPA, demand side management and energy efficiency, and the emerging

[7] NOPR, P 56.

Environmental Protection Agency rules regarding hazardous air pollutants, interstate air pollution transportation, industrial boiler control technology, water, and coal combustion byproducts. During the IRP process, State regulators ensure that such State and federal public policy requirements are addressed in the selection of resources to serve loads. Because this State-regulated selection of resources includes the selection of the transmission facilities that will be used to deliver energy from those resources to load, any transmission expansion that results from the resource procurement aspects of the IRP process has been vetted and approved by State regulators as meeting State and federal public policy requirements. As a result, in meeting their statutory obligations to serve native load customers reliably and economically (and with State guidance, oversight, and approval), the Southern Companies already develop the transmission facilities necessary to serve load in a manner that appropriately incorporates State and federal public policy.

25. Thirdly, any additional requirement for Southern Companies or their regional planning process to include public policy in transmission planning would be inconsistent with – and would likely be in direct conflict with – the public policy requirements and methods of implementation required by Southern Companies' State regulators. This inconsistency/conflict could be exacerbated if the requirement to include public policy at the regional level (*i.e.*, outside of the IRP context) means that a State-regulated public utility would be required to plan and construct its transmission system to implement the public policy requirements of another State. For instance, such expansion could adversely impact the economics or reliability of resource procurement/transmission planning decisions made by State regulators during the utility's IRP process (and therefore adversely impact service to native load). Worse, the costs of such expansion could be borne by the utility's retail customers, thus resulting in the retail customers

of one State subsidizing retail customers of another State. Such policy proposals would have to be addressed in the State-regulated IRP and RFP processes described above. Any discrepancies could only be reconciled if the resulting supply or demand resources and transmission are certificated by the State.

26. It is worth noting that the States have more than adequate mechanisms to ensure that public policy is included in the transmission planning processes of utilities subject to their jurisdiction. While this State oversight and enforcement may not exist in RTO regions where the transmission planning is conducted by the RTO rather than by the State-jurisdictional utilities, any directive issued in a Final Rule that would attempt to use federal authority to enforce State public policy could significantly undermine State authority in that arena by choosing a different (and potentially conflicting) public policy enforcement mechanism.

27. The NOPR's regional planning proposals and non-incumbent sponsorship proposals could significantly impair the ability of Southern Companies' RFP and IRP processes to procure least-cost, reliable supply-side resources for native load. The process that the NOPR proposes for the selection of the transmission lines to be included in the regional transmission plan (and their builders/owners), and the NOPR's proposals for developing the regional plan, would likely cause serious problems and delays in the RFP and IRP processes. In fact, the NOPR's proposals appear to be incompatible with the RFP and IRP processes conducted by Southern Companies.

28. To select the transmission lines to be included in the plan (and the entities that construct/own them), the NOPR proposes to: (1) allow those entities that meet some as-yet-unspecified (but Commission-approved) qualification criteria to submit proposals to sponsor

proposed projects in the regional transmission process;[8] (2) require all proposals to be submitted on a single date each year;[9] (3) require each transmission provider to amend its OATT to set forth "the process for evaluating whether to include a proposed transmission facility in the regional transmission plan"[10]; and (4) presumably require transmission providers to include facilities in the regional plan if the Commission-approved evaluative process contained in the OATT would permit their inclusion. The NOPR also proposes that when a sponsoring entity's proposal is not included in the immediate planning cycle:

> if the project's sponsor resubmits that proposed project in a future transmission planning cycle, that sponsor would have the right to develop that project...even if one or more substantially similar projects are proposed by others in the future transmission planning cycle. The OATT must state that [the proposing stakeholder's] priority to develop the proposed facility continues for a defined period of time (*e.g.* for resubmission annually in subsequent transmission planning cycles over a 5-year period).[11]

29. In addition, the NOPR proposes to require transmission providers to "participate in a regional transmission planning process that produces a regional transmission plan".[12] More specifically, the NOPR proposes to require that "each regional transmission planning process consider and evaluate transmission facilities and other non-transmission solutions that may be proposed and develop a regional transmission plan that identifies the transmission facilities that cost-effectively meet the needs of transmission providers, their transmission customers, and other stakeholders."[13]

---

[8] NOPR, P 90.

[9] NOPR, P 91.

[10] NOPR, P 92.

[11] NOPR, P 95.

[12] NOPR, P 50.

[13] *Id.*, P 51.

30. As an initial matter, the regional planning process proposed by the NOPR would constitute top-down planning because proposals made during the regional planning process can alter the underlying bottom-up transmission plans (*e.g.*, the IRP). Top-down planning is inherently inconsistent with integrated resource planning, which is a bottom-up process.

31. As previously stated, integrated resource planning is a statutorily required, State-regulated process with the sole purpose of procuring resources and planning/expanding an individual public utility's transmission facilities in an integrated, holistic manner to serve that individual public utility's retail and native load customers on a least-cost, reliable basis. The IRP process is driven solely by the energy needs of that individual utility's retail and native load customers – these customers are the foundation of (or a portion thereof) in the bottom-up planning process.

32. In light of the proposed requirement to hardwire into the OATT an unknown and untested mechanical process for selecting transmission expansion proposals, it is conceivable that the NOPR's top-down planning proposal would permit stakeholders with no interest or duty to serve the public utility's retail and native load customers (who rely on the IRP process to serve them on a least-price, reliable basis) to propose – in the name of meeting "regional needs" – projects that could seriously and adversely impact the economics and possibly the reliability of the IRP previously developed and approved in the State-regulated IRP process before that IRP could be implemented. For example, a stakeholder could sponsor a major high voltage transmission line and associated substations and transformers which would likely change the system power flows in a way that would create congestion on the underlying transmission grid. A public utility serving retail and native load could be required to uneconomically modify its previously developed expansion plan (including its IRP) to relieve the congestion and/or be

exposed to Transmission Loading Relief actions which increase the cost of generation supply and threaten reliability. In such a circumstance, if the public utility had not already executed a power purchase agreement with a winning RFP bidder, the public utility could either petition its State regulators to conduct a new RFP/IRP process (which may not be able to procure resources in time to meet the forecasted demand) or simply allow ratepayers to pay higher prices than their State regulators had approved (and hope those State regulators deem the costs to be prudently or otherwise unavoidably incurred). From an independent power producer's perspective, the regional planning process could frustrate bidders into an RFP by ruining the economics of their bids (and potentially having the RFP awarded to the wrong bidder).

33. Further, the NOPR's set date for submitting proposed expansion projects, if applied to transmission facilities included in an IRP, would conflict and interfere with the RFP/IRP process. Timelines for evaluating, selecting, contracting and certifying resources procured through an RFP are short and are generally set such that the new generation facilities and the associated transmission necessary to reliably deliver their power to loads can be constructed in time to meet the need date. In addition, the timing of the issuance and implementation of an RFP is not dependent on any regularly scheduled event or tied to any annual cycle. Instead, RFPs are issued and implemented as resource needs are identified, and resource needs can occur at any time and must be met regardless of schedule. As a result, the NOPR's proposal related to non-incumbents and their ability to sponsor projects in the "regional plan" could not only impair the existing RFP processes and the associated IRP, it could bring the IRP process to a standstill until (at the earliest) the deadline for submitting proposals into the regional planning process because the transmission component of the IRP could not be finalized

until the regional process is complete. As a result, service to retail and native load customers could be impaired (or costs could needlessly increase).

34. In addition, each RFP is a closed, competitive bidding process seeking generating resources to fulfill a public utility's duty to serve identified native load customer needs on its transmission system and is not subject to transmission input from any third party. The necessary transmission expansion plan to reliably deliver power from each potential resource proposal is developed as part of the RFP process. There is simply no way for a sponsored transmission facility to be included in an RFP evaluation as they are currently conducted. Therefore, the inclusion of a sponsored facility in the IRP process would likely conflict with the IRP decision-making process.

35. In the event of a dispute over the rights to sponsor and construct transmission facilities identified in an IRP as necessary to link the resource to load, the specter of impending litigation could halt the construction of facilities needed to serve retail and native load in a least-price, reliable manner. Even if a sponsorship dispute does not immediately pertain to facilities identified in an IRP, the ensuing delay in construction of the facilities at issue could introduce significant uncertainty in the future topography of the grid (particularly with respect to in-service dates), which would adversely impact evaluations in any ongoing RFP or IRP process affected by the facilities at issue. The delay in finalizing expansion plans due to disputes could (and would) hold the IRP and RFP processes hostage, thus harming service to native load customers.

36. Taken in combination, the NOPR's sponsorship proposals create incentives for all potential sponsors (both incumbent and non-incumbent) to submit as many proposals for consideration as they believe might reasonably be constructed *someday*. Such a glut of proposals

would "clog the queue" and bog down the planning process with needless evaluation of an unreasonable number of proposals. The sheer number of proposals would make predicting the outcome of the transmission planning process impossible, which in turn would create delay and confusion in the RFP/IRP evaluation process. Additionally, the glut of proposals would amplify the uncertainty and the potential for disputes, litigation and delays as discussed above.

37. The prospect that a non-incumbent proposal would actually evolve to a non-incumbent transmission project raises additional concern about reliability and economics. The Southern Companies' transmission expansion plans are not simply developed at a single point in time and implemented as planned. Rather, the transmission plan is constantly changing to adapt to new information, such as revised (higher or lower) demand forecasts, new native load generating resources resulting from the IRP/RFP processes, and other uses of the transmission system resulting from the OATT process. Transmission facilities may be advanced, delayed, modified, or cancelled in response to these changing decisions. For an incumbent transmission provider, such contingencies are a matter of course, and the incumbent transmission provider's incentives are appropriately aligned with the flexibility to modify, delay or even scrap planned transmission projects that no longer meet firm needs. However, it is not clear how any "contract" with a non-incumbent transmission developer to sponsor and construct transmission facilities included in the transmission plan could provide the same (or even a similar) degree of flexibility required to continuously plan a reliable transmission system at the least practicable cost. Nor is it clear whether and how the transmission planning process resulting from the Final Rule could accomplish this. If the flexibility to delay or scrap non-incumbent projects that have been included in the regional transmission plan is unavailable, the regional transmission system will necessarily be planned and constructed in a sub-optimal manner – *i.e.*, it will not be cost-

effective or efficient and will not meet regional needs. In such circumstances, if the transmission provider has contracted with a non-incumbent to construct a facility that no longer meets system needs and should not be included in the plan, the transmission provider will be faced with the choice of planning the system in an optimal manner and litigating any disputes that arise or allowing the non-incumbent facility to go forward and constructing the system in a sub-optimal way (thereby increasing costs to customers).

Further affiant sayeth not.

This 28 day of September, 2010.

Garey C Rozier

GAREY C. ROZIER

Sworn to and subscribed before me this 28 day of Sept. 2010, by Garey C. Rozier, who is personally known to me.

Deanna K. Frankowski

NOTARY PUBLIC
My Commission Expires On
MY COMMISSION EXPIRES 01/10/2011

DEANNA K. FRANKOWSKI NOTARY PUBLIC ALASKA STATE AT LARGE

ATTACHMENT B-3

SUPPLEMENTAL AFFIDAVIT OF BRYAN K. HILL

Originally Included as “Exhibit 1” to Southern Companies’ Request for Rehearing

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation	)	Docket No. RM10-23-000
by Transmission Owning and Operating	)	
Public Utilities	)	

SUPPLEMENTAL AFFIDAVIT OF BRYAN K. HILL

I, Bryan K. Hill ("Affiant"), being duly sworn, depose and state as follows:

1. My name is Bryan K. Hill. I am employed by Southern Company Services, Inc., and my business address is 600 18th Street North, Birmingham, Alabama 35291. Currently, I am employed as Planning Manager for Southern Company Transmission, Transmission Planning. My responsibilities and duties as Planning Manager include the oversight of regional, interregional and interface transmission planning as well as oversight of all transmission service studies conducted under the Southern Companies' Open Access Transmission Tariff. I graduated from Auburn University in 1995 with a bachelors' degree in Electrical Engineering. I have over fifteen (15) years of experience in the utility industry including distribution engineering, distribution planning, transmission planning, transmission service and transmission policy. My experience in transmission includes power flow studies, generator interconnection studies, transmission service requests, interface transfer analysis, regional and interregional planning, industry committee participation, development and implementation of Attachment K of Southern Companies' Open Access Transmission Tariff and administration of Southern Companies' generator interconnection process as related to the Large Generator Interconnection Procedures/Small Generator Interconnection Procedures. In addition, I not only served on the team that assisted in developing/implementing the Eastern Interconnection Planning

Collaborative ("EIPC"), but I also served on the team that developed/prepared the bid proposed and accepted by the DOE under FOA 0000068, Topic A (Interconnection Level Analysis and Planning for the Eastern Interconnection). During 2010, I served as chairman of the EIPC's Steady-State Modeling and Load Flow Working Group, which is responsible for the transmission analysis and load flow model development associated with the cooperative agreement awarded by the DOE.

2. I believe certain factual assumptions and preliminary findings set forth in the Commission's Order No. 1000 are incorrect as a general matter, and are certainly incorrect to the extent the Commission assumes that they are consistent with or representative of the transmission system and transmission planning processes (and the results of those processes) in the bilateral markets in the Southeast. This supplemental affidavit is intended to provide information – in addition to that contained in my initial affidavit in this proceeding[1] – that the Commission can use to better evaluate the potential impacts (primarily detrimental) of Order No. 1000 on transmission planning and the reliability of the transmission system in the Southeast,[2] as well as Order No. 1000's adverse impacts on Southern Companies' State-mandated duty to reliably serve native load.

I. Review of Southern Companies' Transmission Planning Processes

3. Although I described Southern Companies' planning processes in significant detail in my initial affidavit, the unspoken assumptions of Order No. 1000 indicate that a brief review may be helpful. In bilateral markets such as those in the Southeast, transmission

[1] *See* Comments of Southern Company Services, Inc. at Attachment A, Affidavit of Bryan K. Hill ("Hill Affidavit").

[2] For purposes of these comments, in discussing transmission planning practices in the Southeast, I do not include the FRCC, as it is relatively unique given its peninsular nature.

expansion is driven by the need to implement resource decisions supported by long-term firm transmission commitments and by changes in customer loads.[3] By "resource decisions," I mean the decisions made by load-serving entities ("LSE") and OATT customers regarding which specific resources will serve their *long-term firm* capacity needs.[4] In bilateral markets in the Southeast, these resource decisions determine how the transmission system will be used in the future.[5] Because these decisions determine long-term customer commitments regarding future system usage, they create the "need" that drives transmission expansion (to the extent the system is not already capable of meeting the need).

4. In bilateral markets, the transmission system is specifically planned and constructed to accommodate this committed, long-term future system usage – *i.e.*, so that long-term resource decisions can be reliably delivered with no congestion. Stated differently, the transmission system is <u>not</u> planned and expanded to accommodate prospective (*i.e.*, speculative) resource decisions – for example, to import from hypothetical or uncommitted generation – because: (A) there would be no reliability need or market commitment for such transmission facilities; (B) if a commitment arises for such transmission (*i.e.*, if a resource decision is made),

---

[3] Hill Affidavit at P 8. There are situations when transmission is expanded for operational flexibility and reliability purposes at the request of a customer or load serving entity.

[4] For example, wholesale customers make such decisions by canvassing the market for available power producers with whom they could execute long-term power purchase agreements (and then request the necessary transmission service to access that generation). In comparison, native load resource decisions are made through state-regulated integrated resource planning ("IRP") processes, which frequently include the use of requests for proposals ("RFP") to canvass the market for available generation (factoring in the associated transmission costs).

[5] *See, e.g., NERC 2010 Long Term Reliability Assessment* at pp. 137-38 ("[In the Southeast], entities go through various generation expansion study processes to determine the quantity and type of resources to add to the system in the future.... Load forecasts are reviewed yearly and resource mix analyses are performed to determine the amounts and types of capacity resources required to meet the companies' obligations to serve. By the time the reliability analysis is conducted, those capacity resources have been committed by the companies and have high probability of regulatory approval. Power purchase agreements are also contracted from the market by that time. The resulting inputs to the reliability analyses are known or have very high confidence.... [E]ntities within this subregion do not apply a confidence factor to... Conceptual resources.... If there are no confirmed transmission service requests or native load reservations identifying these facilities as the source, then these facilities are subsequently categorized as Conceptual [*i.e.*, no confidence factor is applied].").

the necessary transmission will be planned to ensure that it can be delivered without congestion; and (C) speculative expansion introduces unnecessary issues of subsidies and cost socialization which would undermine prudent generation siting.

5. The transmission system is also not planned or constructed to accommodate short-term resource decisions or opportunity purchases because (A) LSEs and OATT customers have already selected the resource options that will serve their long-term capacity requirements (which selection considers any transmission expansion that may be required); (B) customers are generally unwilling to pay the incremental cost of any transmission expansion necessary to accommodate such purchases; and (C) the lead time needed to identify, site and construct any necessary transmission facilities is typically too long to justify the transaction. However, as discussed in my initial affidavit, transmission expansion to provide uncongested, long-term firm transmission service in bilateral markets typically generates more than sufficient headroom to accommodate robust short-term opportunity purchases.[6]

6. When a customer makes a long-term resource decision and seeks firm transmission service to ensure reliable delivery of that resource, Southern Companies begin the "optimization" process of planning to meet that need. Southern Companies' planning includes coordination with neighboring transmission providers to meet customers' needs in least-cost fashion. Long before the Commission issued Order No. 890, Southern Companies' planning process included (and still includes) regular coordination with the transmission providers in their region and with neighbors adjacent to their region to plan their system in the most cost-effective and efficient manner.[7] For example, Southern Companies have coordinated with neighboring

[6] Hill Affidavit at P 16.

[7] Hill Affidavit at PP 10-40.

systems using existing bilateral reliability agreements and SERC Reliability Corporation ("SERC") planning processes.[8] Although bilateral reliability agreements require Southern Companies to coordinate with their neighbors to ensure reliability, these vehicles have also consistently and *proactively* been used to conduct joint studies with neighboring systems to reduce transmission capital costs – *i.e.*, to meet customer needs for long-term, firm, congestion-free transmission more efficiently and cost-effectively through coordination.[9]

7. In addition, when Southern Companies and the other planning entities in SERC coordinate through SERC study groups[10] to examine the simultaneous feasibility of their respective local plans, they identify when additional efficiencies could be derived from further planning coordination between individual companies. Those companies then, through their bilateral reliability agreements, conduct additional studies to coordinate their local plans to meet their pre-determined firm transmission commitments in least-cost fashion.

8. Southern Companies and the entities that now comprise the Southeastern Regional Transmission Planning ("SERTP") sponsors began coordinating their transmission planning with stakeholders in 2006, several months before the issuance of Order No. 890. This regional planning process serve as the basis upon which Southern Companies comply with Order

[8] Hill Affidavit at PP 10-40.

[9] *Id.*

[10] *See e.g., NERC 2010 Long Term Reliability Assessment* at p. 107 ("To minimize reliability concerns within the Region, entities engage in individual assessment studies and participate in a host of committees designed to perform system studies and address industry issues that are important to reliability. Assessment studies include steady-state power flow studies, dynamics/stability studies, and transmission transfer capabilities both internal and external to SERC. The Region relies on the SERC NTSG (Near-term Study Group), SERC LTSG (Long-term Study Group), SERC DSG (Dynamics Study Group) and SERC SCDWG (Short Circuit Database Working Group) to coordinate these studies in order to ensure the system is adequate for projected peak demands").

No. 890, thus "ensur[ing] that transmission providers do not unduly discriminate in the selection of which facilities they choose to construct to the detriment of their customers."[11]

9. It should be noted that, in bilateral markets such as Southern Companies', the cost of transmission is considered in customers' resource planning decisions, which decisions are not made by transmission planners. Native load (which accounts for approximately 85% of the load of Southern Companies) uses the state-regulated IRP process to assess the transmission costs associated with potential resources, and OATT transmission customers use the OATT study processes to assess transmission costs associated with their resource decisions.

10. During the transmission planning process (which simply plans and constructs the transmission necessary to implement customers' pre-determined resource decisions), Southern Companies' transmission planners do not revisit, revise or otherwise influence the resource decisions of any customer, whether native load or OATT. Therefore, contrary to statements in the NOPR and in Order No. 1000, the role of Southern Companies' transmission planning is not to "reduce *overall* costs to serve"[12] because the term "overall" implies that transmission planners are engaged in resource planning.

II. Order No. 1000's "Need for Reform" Does Not Exist in the Southeast, and Thus its Generically Applicable Remedial Actions Are Not Helpful.

A. Order No. 1000's Perceptions of Existing Planning Processes' Inadequacies Are Incorrect with Respect to the Planning Processes in the Southeast.

11. In Order No. 1000, the Commission finds that:

---

[11] Order No. 890-A at P 179; *e.g.*, Hill Affidavit at PP 18-23.

[12] Order No. 1000 at P 71 ("The Proposed Rule stated that, when conducting transmission planning to serve native load customers, a prudent public utility transmission provider will not only plan to maintain reliability and consider whether transmission facilities or other investments can reduce the overall costs of serving native load, but also consider how to enable compliance with relevant Public Policy Requirements").

> ...inadequate transmission planning and cost allocation requirements may be impeding the development of beneficial transmission lines or resulting in inefficient and overlapping transmission development due to a lack of coordination, all of which contributes to unnecessary congestion and difficulties in obtaining more efficient or cost-effective transmission service[13] [and that]
>
> ...
>
> without the requirement to meet the Order No. 890 transmission planning principles, a regional transmission planning process will not have the information needed to assess the impact of proposed transmission projects on the regional transmission grid. Additionally, absent timely and meaningful participation by all stakeholders, the regional transmission planning process will not determine which transmission project or group of transmission projects could satisfy local and regional needs more efficiently or cost-effectively.[14]

12. Order No. 1000 also notes that:

> [T]ransmission providers are currently under no affirmative obligation to develop a regional transmission plan that reflects the evaluation of whether alternative regional solutions may be more efficient or cost-effective than solutions identified in local transmission planning processes.[15]

13. As described below, the implication that "inadequate planning" in the Southeast (arising from "a lack of coordination") has impeded the development of "beneficial" transmission or resulted in "inefficient" transmission development – and thereby led to "congestion and difficulties obtaining more efficient or cost-effective transmission service" – is incorrect. Further, the idea that, without Order No. 890's planning principles, transmission providers in the Southeast "*will not* have the information needed" to assess a proposed project's regional impacts is also incorrect. In addition, Order No. 1000's finding that participation by "all stakeholders" is necessary, or else transmission providers in the Southeast "*will not* determine which transmission project or group of transmission projects could satisfy local and regional

[13] Order No. 1000 at P 43.

[14] Order No. 1000 at P 152.

[15] Order No. 1000 at P 3.

needs more efficiently or cost-effectively" is, again, incorrect. More importantly, the assumptions underlying the "need for reform" (such as the idea that "beneficial" transmission may be overlooked) indicate that the Commission may need additional clarification regarding transmission planning by vertically integrated utilities in bilateral markets such as those in the Southeast. Therefore, the Commission's "need for reform" does not apply to transmission planning in the Southeast or to Southern Companies specifically.

14. The Commission is incorrect to imply that, in bilateral markets in the Southeast, "beneficial" transmission has been impeded by "inadequate" and uncoordinated planning (and therefore congestion exists and "more efficient" transmission service is unavailable). Because each utility's system is planned at the local level to meet LSEs' and OATT customers' transmission service needs (*i.e.*, to provide reliable, congestion-free delivery of long-term firm energy from pre-selected resources), the only "beneficial" transmission facilities are those that reduce the capital costs of transmission. As a result, in bilateral markets, there is generally no need for – and therefore no benefit to customers from – an upgrade that "increases" reliability beyond the point necessary for providing firm service in accordance with NERC reliability criteria and any local planning criteria.[16] Such an upgrade would only increase transmission costs without meeting a need. Similarly, in bilateral markets, there is no need for an upgrade that permits access to remotely located renewable resources unless a customer has decided to purchase power from that resource – such an upgrade would largely be unused (except perhaps to make short-term opportunity purchases), as LSEs' and OATT customers' needs for the delivery of their long-term firm energy purchases have already been planned for and met at the

[16] Southern Companies' local planning criteria are set forth on the Southeastern Regional Transmission Planning website at http://www.southeasternrtp.com/pdf/Voltage_and_Thermal_Guidelines.pdf. *See also* n. 3.

local level. Further, in bilateral markets such as Southern Companies, there is no need for additional transmission expansion to relieve congestion because the system is planned from the outset to eliminate congestion for long-term firm delivery of power.

15. The requirements of Order No. 1000 are highly unlikely to provide additional benefit in bilateral markets because there will be no "driver" for additional transmission expansion during the creation of a "regional plan" because LSEs' and customers' needs are addressed at the local level. Because resource decisions are made prior to transmission expansion (including any resource decisions related to public policy), no additional transmission will be needed to access currently untapped resources (renewable or otherwise) absent a long-term service commitment because the resources themselves would not meet a long-term need. Therefore, any exercise, such as additional regional coordination procedures or the development of a "regional plan", aimed at "proactively" (*i.e.*, prospectively, in advance of customers' resource decisions) planning regional transmission facilities are not reasonably expected to result in construction of additional facilities

16. As described in the section above, transmission planners in the Southeast already coordinate with one another to identify the facilities that are "beneficial" to their LSEs and OATT customers. Southern Companies are under a state-imposed duty to meet their native load's incremental transmission needs on a least-cost basis (through their IRP processes and prudency reviews); to meet that duty, Southern Companies coordinate with their neighboring utilities to minimize the total transmission capital costs required to serve the resource decisions made through the IRP process. Because Southern Companies are under a Commission-imposed duty to treat OATT customers comparably to their native load, Southern Companies' also plan their system to meet OATT customers' transmission needs in the same manner as native load

customer needs – *i.e.*, through coordination with neighboring utilities to reduce total transmission costs.

17. As the transmission planning processes in the Southeast already include regional coordination to achieve least-cost planning (which is the Commission's stated goal of Order No. 1000), the "need for reform" upon which Order No. 1000 is premised does not exist in the Southeast. Because customer needs are well-defined prior to transmission planning at the local level, they are addressed at the local level through least-cost planning – even when least-cost planning requires coordination with neighboring utilities. Consequently, the requirement to develop a "regional transmission plan" is – in my opinion, based on my understanding of Order No. 1000, as informed by my familiarities with the Southern Companies, as well as my educational and professional experience – highly unlikely to provide any incremental benefit to transmission planning or expansion.

18. To the extent any additional transmission capital cost savings might be found at the regional level (which would arise only due to a potential oversight at the local level), the existing Order No. 890 processes provide stakeholders with more than enough information and opportunity to point out such savings. In my opinion, based on my experience, education and familiarity with transmission planning in the Southeast (and by Southern Companies), I do not expect anything additional to come out of more regional planning processes and/or a resulting regional plan. Because of the extensive coordination between local transmission planners in the Southeast in pursuit of least-cost transmission planning, it is highly unlikely that a stakeholder could develop a more efficient or cost-effective regional transmission solution that would delay or mitigate the need for the transmission solution previously identified by coordinated local

planning processes (*i.e.*, a solution that would result in less transmission capital expenditures by the transmission providers involved).

19. Regardless, as noted in my initial affidavit,[17] even if a regional transmission plan is created, the existence of such a plan would not facilitate the construction of any facilities that may be identified. Although State-imposed prudency requirements provide considerable incentive to construct more cost-effective facilities (if any are identified during the planning process), the mere existence of a regional transmission plan does not make construction – or even the identification – of facilities in that plan any more likely, as such facilities will only be constructed if they implement an existing resource decision made at the local level and/or accommodate load growth.

20. With respect to assessing the benefits of additional interregional facilities, as noted in my initial affidavit, the existing OATT study and planning processes offer an effective means for stakeholders to examine the benefits of interregional facilities to access resources in (or export resources to) neighboring regions.[18] There is no current need for additional inter-regional coordination.

III. Order No. 1000 Fails to Adequately Protect Against Its Adverse Reliability Impacts.

21. In light of the adverse reliability impacts that could result from delays to or abandonments of transmission construction upon which incumbent public utilities rely for reliability, Order No. 1000 proposes two mitigation strategies (*i.e.*, the reevaluation requirement and the enforcement action waiver, as described below). Neither of Order No. 1000's mitigation

---

[17] Hill Affidavit at P 42.

[18] Hill Affidavit at PP 30-40.

strategies adequately protects incumbents, their native load or their OATT customers from the harm to reliability and the impairment of service obligations that could arise from a delay in or a nonincumbent's abandonment of construction.

A. The Requirement to Reevaluate the Regional Transmission Plan Fails to Protect Against the Adverse Effects of a Construction Delay.

22. In Order No. 1000, the Commission states:

> Given that incumbent transmission providers may rely on transmission facilities selected in a regional transmission plan for purposes of cost allocation to comply with their reliability and service obligations, **delays in the development of such transmission facilities could adversely affect the ability of the incumbent transmission provider to meet its reliability needs or service obligations.**[19]
>
> *   *   *
>
> In light of comments received in response to the Proposed Rule, **we also require each public utility transmission provider to amend its OATT** to describe the circumstances and procedures under which **public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays** in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation **require evaluation of alternative solutions**, including those proposed by the incumbent transmission provider, **to ensure the incumbent transmission provider can meet its reliability needs or service obligations.** We appreciate that there are many sources of delay that could affect the timing of transmission development, and **do not intend to require constant reevaluation of delays that do not materially affect the ability of an incumbent transmission provider to meet its reliability needs or service obligations.** Our focus here is on ensuring that adequate processes are in place to determine whether delays associated with completion of a transmission facility selected in a regional transmission plan for purposes of cost allocation have the potential to adversely affect an incumbent transmission provider's ability to fulfill its reliability needs or service obligations. Under such circumstances, an incumbent transmission provider must have the ability to propose solutions that it would implement within its retail distribution service territory or footprint that will enable it to meet its reliability needs or service obligations. **If such other solution is a transmission facility, public utility transmission providers in the regional transmission planning process should evaluate the proposed solution for possible selection in the regional transmission planning process for purposes of cost allocation.** As we have explained elsewhere in this Final Rule, nothing herein restricts an incumbent transmission provider from developing a local transmission solution that is not

[19] Order No. 1000 at P 263

eligible for regional cost allocation to meet its reliability needs or service obligations in its own retail distribution service territory or footprint.[20]

23. In my opinion, based on my transmission planning experience, education and knowledge of Southern Companies' and various Southeastern transmission planning processes and systems, the reevaluation process described in the above quotations from Order No. 1000 is flawed in multiple aspects and will likely result in harming reliable service to native load and OATT customers.

24. As an initial matter, Order No. 1000 misplaces the prerogative and process of reevaluation. Because local transmission plans will *rely upon* the completion of the selected facility (for potentially varying reasons, including reliability), those local transmission planners and planning authorities[21] – and not the regional planning process, as indicated by Order No. 1000 – are the appropriate entities to reevaluate the effects of a delay on their systems. It is the local planning authorities and transmission planners, and not the regional planning process, that are subject to State mandates to serve native load and that are required to comply with NERC Reliability Standards. Therefore, they are in the best position to determine whether a delay will affect their ability to comply with those requirements.

25. The reevaluation requirement also targets the wrong transmission plan. As stated in Order No. 1000, there is no requirement that transmission expansion follow the regional

[20] Order No. 1000 at P 329 (footnote omitted (emphasis added).

[21] Although Order No. 1000 imposes the reevaluation requirement upon "public utility transmission providers" and "the regional planning process," NERC Reliability Standards related to transmission planning do not apply to transmission service providers, to stakeholders or to the regional planning process. Rather, they apply only to entities that are NERC-registered transmission planners and planning authorities. For purposes of this supplemental affidavit, because Order No. 1000 is unclear, I will assume that the Commission intends the reevaluation requirement to apply only to those NERC registered entities responsible for transmission planning – *i.e.*, transmission planners and planning authorities.

transmission plan.[22] Thus, requiring transmission providers to reevaluate the regional plan, which may not be the plan(s) actually used for transmission expansion in the region, could be a pointless waste of resources and time. Rather, each incumbent transmission planner and planning authority should be permitted to reevaluate its own local transmission plan to determine whether a delay in constructing a regional facility will adversely impact reliability on the incumbent's system.

26. The threshold of whether a delay "materially" affects the ability of an incumbent to meet its reliability requirements and service obligations appears to be misguided, so far as it applies to system planning and operations in bilateral markets like Southern Companies'. If a delay will adversely affect the ability of an incumbent transmission planner or planning authority to meet its reliability requirements over a long-term planning horizon[23] (*i.e.*, to comply with NERC reliability standards or local planning criteria), NERC standards would require the affected transmission planner or planning authority to adopt a "corrective plan" to alleviate the potential reliability standard violation that would otherwise occur. In other words, from a planning perspective, the delay would either adversely affect an incumbent's compliance with Reliability Standards or local planning criteria (and would therefore require the creation of a corrective plan) or it would not (and would therefore require no action whatsoever).

27. A corrective plan may include constructing additional transmission facilities and/or identifying potential operational readjustments in order to mitigate the violation of a

---

[22] Order No. 1000 at P 153 ("...the transmission planning requirements adopted here do not address or dictate which transmission facilities should be either in the regional transmission plan *or actually constructed*") (emphasis added).

[23] The long-term planning horizon should be distinguished from the short-term (less than one year) operational horizon, which is governed by NERC Reliability Standards that do not apply to transmission planners or planning authorities.

Reliability Standard that would otherwise occur. It is important to understand that even if a corrective plan requires only a "minor" potential operational readjustment, that "minor" operational adjustment is *necessary* to avoid the violation of a Reliability Standard or local planning criteria. Thus, there are no "immaterial" effects on a transmission planner or planning authority's ability to maintain reliability because any effect whatsoever indicates a potential violation of a Reliability Standard or local planning criteria (and therefore a risk to reliability).

28. To the extent that Order No. 1000 prevents a transmission planner or planning authority from reevaluating its local plan unless the adverse effect on an incumbent's service obligations is "material," that threshold is meaningless and confusing because no such impact on service obligations would occur absent an adverse impact on reliability (and, as noted above, there are no "immaterial" adverse impacts on reliability). Further, such a limitation could prevent a transmission planner or planning authority from taking actions necessary to maintain reliability.

29. In addition, the requirement to include a "procedure" in a transmission provider's OATT to reevaluate the transmission plan could conceivably conflict with NERC Reliability Standards that already require annual reevaluations of the local transmission plan. Regardless, to the extent the procedures required by Order No. 1000 could limit the flexibility of an incumbent, of its own volition or in accordance with NERC requirements, to reevaluate its local plan and determine whether a delay adversely impacts reliability – or to the extent the procedures could otherwise interfere with the timely implementation of a corrective plan – the procedures themselves adversely impact reliability.

30. Order No. 1000 assumes – optimistically – that the reevaluation procedures will protect against the effects of a delay (and points to these procedures as justifying the Order's nonincumbent provisions).[24] The Commission must understand that there is absolutely no guarantee that such is the case. First, even if an incumbent can reevaluate its plan, it can have no way of predicting a delay in advance and, once apprised of a delay, an incumbent may not have the time to construct any facilities that may be needed to avoid adverse impacts to the system. Second, although an incumbent can implement mitigation procedures to avoid violations of NERC Reliability Standards, the timeframe of a discovery of a delay could necessitate a severe mitigation plan that affects operations – for example, some situations could require *pro rata* curtailments of firm transmission or even load shedding in order for an incumbent to remain in compliance with NERC reliability standards. Thus, the Commission should realize that the reevaluation requirement is not a failsafe, nor is it sufficient, to maintain service reliability and/or to meet native load service obligations in the face of delays.

31. Further, as addressed in my initial affidavit,[25] if a transmission developer delays construction of a facility upon which a transmission provider has relied when granting a request for firm OATT transmission service, the delay may adversely impact the incumbent's ability to meet OATT service obligations. For example, the delay could require *pro rata* curtailments of firm service, generation cuts or load shedding.

32. In addition, although it is unclear, Order No. 1000 could be construed to require an incumbent transmission provider to "propose" its corrective plan at the regional process for

---

[24] Order, P 268 ("For the foregoing reasons, and in light of the evaluation procedures required in section III.B.3 below, the Commission finds that there is sufficient justification in the record to implement the requirements regarding rights of first refusal contained in Commission-jurisdictional tariffs or agreements").

[25] *See, e.g.*, Hill Affidavit at P 57.

review (if the plan includes transmission construction within its local footprint). If that is the case, such review could potentially result in the corrective plan being constructed by an entity other than the incumbent (if the corrective plan is selected for regional cost allocation). To the extent Order No. 1000 requires review of an incumbent's corrective plan by the regional process or permits third parties to construct the corrective plan, Order No. 1000 would impair reliability.

33. To maintain system reliability, it is imperative that an incumbent be able to construct and implement – without any delay – its own corrective plans within its service territory. Requiring an incumbent transmission provider to submit its corrective plan "proposal" to the regional process could delay implementation of the plan (which could render the plan moot and/or prevent its timely implementation) and could remove the incumbent's ability to implement the corrective plan altogether (*e.g.*, if another entity were selected to construct the plan). Both of these outcomes could harm reliability and would interject third parties who are not responsible for compliance with relevant legal requirements, such as the State-mandated duty to serve, into the decisionmaking process of the incumbent (who *is* responsible for compliance).

34. Assuming a delay will last only a matter of months (and, as far as the incumbent utility knows, the construction will eventually be completed), the corrective plan will likely be a solution that is operational in nature because an incumbent would probably not construct facilities that are duplicative. Instead, the incumbent would use an operational "workaround" until the delayed facility comes into service – *e.g.*, uneconomic redispatch, *pro rata* curtailments of firm service, generation cuts or load shedding. Although an operational corrective plan would avoid a violation of NERC reliability standards, it would almost certainly adversely impact the incumbent's native load and firm OATT commitments (through higher energy prices due to uneconomic redispatch, generation cuts or the shedding of wholesale or native load).

35. As Order No. 1000 appropriately points out, a delay in transmission construction can create reliability problems for incumbents whose systems rely upon the facility being completed on time.[26] The reliability problems caused by delays are no less severe than when a nonincumbent abandons construction – in fact, as long as the delay lasts, a delay is the equivalent of abandonment, from a reliability impact perspective. Thus, there is no reliability-related reason to relieve incumbents from NERC enforcement actions in circumstances where a nonincumbent *abandons* construction of a facility[27] but failing to do so when construction of a facility is *delayed.*

B. Waiving NERC Enforcement Actions Fails to Protect Against the Adverse Effects of a Nonincumbent's Abandonment of Construction.

36. In Order No. 1000, the Commission states:

> The Commission is sensitive to the concerns of some commenters that contend that existing transmission providers run the risk of violating NERC reliability standards in the event that a nonincumbent transmission developer abandons a transmission facility meant to address a violation. To address such concerns, the Commission clarifies that, if a violation of a NERC reliability standard would result from a nonincumbent transmission developer's decision to abandon a transmission facility meant to address such a violation, the incumbent transmission provider does not have the obligation to construct the nonincumbent's project. Rather, the transmission provider must identify the specific NERC reliability standard(s) that will be violated and submit a NERC mitigation plan to address the violation. Provided the public utility transmission provider follows the NERC approved mitigation plan, the Commission will not subject that public utility transmission provider to enforcement action for the specific NERC reliability standard violation(s) caused by a nonincumbent transmission developer's decision to abandon a transmission facility.[28]

37. In the quotation above, Order No. 1000 shifts from a directive aimed at transmission planning to a directive that is aimed, at least in part, at transmission operations.

[26] *E.g.*, Order No. 1000 at PP 329.

[27] Order No. 1000 at P 344.

[28] Order No. 1000 at P 344 (footnote omitted).

This provision is confusing with respect to the requirement to submit a mitigation plan that describes subsequent violations of reliability standards, as such plans are either: (a) generally not submitted except in an enforcement context, at which point a violation has already occurred; or (b) developed to avoid violations altogether, in which case the waiver of a NERC enforcement action is meaningless because no violation has occurred.

38. Regardless, in my opinion, as informed by my familiarities with the Southern Companies' transmission system and by my educational and professional experience, holding a transmission provider harmless from a NERC enforcement action is insufficient to mitigate adverse reliability impacts caused by a nonincumbent's abandonment of construction. To put it differently, Order No. 1000's proposal to waive NERC enforcement actions – assuming an incumbent can: (a) develop a mitigation plan, (b) obtain NERC's approval of the plan, and (c) implement the plan – does not <u>protect</u> against, but instead <u>reacts</u> to, the problems caused by a nonincumbent's abandonment of construction of a regional project.

39. To clarify: it is correct and appropriate not to penalize a transmission provider for any violations of any applicable Reliability Standards that occur as a result of a nonincumbent's abandonment of regional facilities – although it is unclear what Reliability Standards would or could be violated in such a circumstance. However, the absence of a penalty does not remedy the effects of a nonincumbent's abandonment.

40. Notably, not only does this provision of Order No. 1000 do nothing to help maintain reliability, it also does not assist in meeting service obligations. A mitigation plan may include load shedding, *pro rata* cuts in generation/firm service and other remedial measures that impair the provision of firm transmission service. Thus, the waiver of NERC enforcement

actions when an approved mitigation plan is implemented will still allow the impairment of service to retail native load and other firm service obligations that would likely occur due to a nonincumbent's dereliction of duty. Nor does the provision address who should bear the costs that would likely be incurred when implementing a mitigation plan (*e.g.*, due to redispatch, load shedding, generation cuts, curtailments, etc.).

IV. Continued Validity of Initial Affidavit

41. I hereby reaffirm that the statements made in my prior affidavit in this proceeding, to the extent they address aspects of the Commission's proposals in the NOPR that are also contained in the Final Rule, continue to be accurate and truthful to the best of my knowledge and belief.

Further affiant sayeth not.

This 22nd day of August, 2011.

Bryan K. Hill

Bryan K. Hill

Sworn to and subscribed before me this 22nd day of August, 2011, by Bryan K. Hill, who is personally known to me.

Deanna K. Frankowski

Notary Public
My Commission Expires On

1-10-2015

ATTACHMENT B-4

OVERVIEW OF THE TRANSMISSION SYSTEM IN THE SOUTHERN COMPANY AREA

William D. McLaughlin

Originally Included as "Attachment C" to Southern Companies' Initial Comments and "Exhibit 4" to Southern Companies' Request for Rehearing

Overview of the Transmission System in the Southern Company Area

William D. McLaughlin
Transmission Planning
Southern Company Services
Birmingham, AL USA
wdmclaug@southernco.com

***Abstract*—This paper provides an overview of the current status of the transmission system in the Southern Companies' service areas in Georgia, Alabama, northwest Florida, and coastal Mississippi including a discussion of the approaches utilized in planning and expanding the transmission system. The paper also discusses current and emerging challenges in ensuring safe, reliable, and economical system expansion as we enter a period of dramatic transition in the mix of available resource technologies, demand side options, and evolving customer load components.**

I. Introduction

The Southern Companies' service area encompasses approximately 122,500 square miles in the southeastern United States and includes 53 tie lines with neighboring transmission systems. The Southern Companies have responsibility for approximately $6.2 billion in transmission assets including more than 27,000 miles of transmission lines.

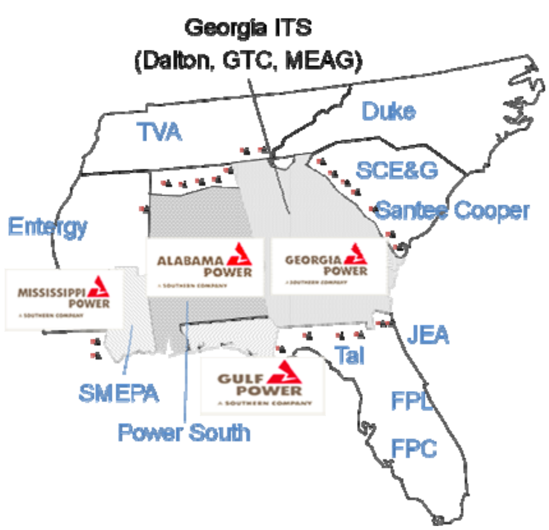


Figure 1. Southern Companies' Service Area *(Shaded)*
The Georgia ITS includes Dalton Utilities, Georgia Transmission Corporation, Georgia Power Company, and the Municipal Electric Authority of Georgia.

The Southern Companies' transmission system is planned and built to provide safe and reliable power deliveries from generation resources to customer loads while enabling an economic dispatch of generation with minimal congestion. Planning of the system is closely coordinated with numerous Load Serving Entities (LSEs) within the service territory and with eleven neighboring transmission systems. The transmission facilities of affiliates Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, and also those of non-affiliates who participate in the Georgia Integrated Transmission System (GA ITS), are planned and operated as a single Balancing Area, meaning that the bulk power facilities perform as a single, aggregated system even though the ownership of individual facilities varies.

The Southern Companies, members of the SERC Reliability Corporation, engage extensively in reliability coordination activities with neighboring systems leading to an extensive transmission network across the southeast. The bulk transmission system within SERC totals 97,256 miles of transmission lines at 100 kV or greater. [1] SERC, which encompasses the fourth largest geographic footprint of the eight NERC Regional Entities, has the highest amount of circuit miles in the Eastern Interconnection and nearly as many circuit miles of transmission as both the second and third largest Regional Entities combined.

II. Southern Companies' Transmission System

A. *Integrated Resource Planning (IRP)*

For the Southern Companies, transmission expansion is a means, not an end. The purpose of building transmission is to enable power to be delivered on a safe, reliable, and economical basis from generating resources to serve consumers, in accordance with the Southern Companies' "duty to serve" obligations under state laws. Resource decisions are based upon state-jurisdictional IRP and RFP processes whereby the total cost of a resource (e.g. capital, fuel, environmental, financing, etc.) is evaluated along with the associated transmission delivery costs (e.g. system upgrades, losses, reserves, etc.). Under this holistic IRP approach, resources that have the lowest total system cost are implemented. This may mean that a distant resource that may appear to be the "cheapest" resource from a generation-only perspective may not be implemented if its combined transmission and generation life cycle cost exceeds that of an alternative resource which is not as "cheap" but is located near a load center. Nonetheless, both local and distant resource options including demand side options are routinely solicited and evaluated under IRP and RFP processes to optimize resource decisions.

Transmission expansion plans are developed to support Load Serving Entities ("LSEs") and other long-term firm transmission customers under the Southern Companies' Open Access Transmission Tariff (OATT) in delivering energy on a firm basis, thereby addressing congestion to enable the economic dispatch of the resources committed to serve their respective customers' loads. Planning to address congestion associated with long-term firm service results in a robust transmission system, which also benefits customers by providing increased flexibility in short-term operations, thereby enabling opportunity purchases to be made from other local or distant resources (which resources may not be routinely available, economical, or willing to commit to an LSE on a long-term basis). Generators, whether IPP or affiliated, that choose not to pursue long-term firm service can utilize short-term service on a firm or non-firm basis as available. In this manner, LSEs connected to Southern Companies' transmission system are able to secure uncongested access to low cost resources on a long-term basis and also to routinely benefit from opportunity purchases which may arise on a short-term basis. [2]

These points were recently recognized by the Department of Energy ("DOE") in its 2009 transmission congestion study.[1] With regard to congestion in the Southeast, DOE found that the "SERC region has a unique philosophy with respect to electric system planning and construction" in that "'[t]he transmission system within SERC has been planned, designed and is operated such that the utilities' generating resources with firm contracts to serve load are not constrained….' Because the southeastern utilities build aggressively in advance of load, there is little economic or reliability congestion within the region."[2]

B. *Transmission System Statistics*

The following tables illustrate the continuing focus on transmission system investment in the Southern Companies' system.

Transmission Line Miles	2001	2002	2003	2004	2005	2006	2007	2008	2009
<100 kV	7,593	7,577	7,614	7,584	7,538	7,407	7,365	7,317	7,661
115 kV	12,268	12,322	12,344	12,471	12,511	12,628	12,701	12,893	12,982
230 kV	5,014	5,161	5,205	5,165	5,220	5,333	5,370	5,359	5,439
500 kV	1,494	1,494	1,494	1,494	1,504	1,532	1,534	1,567	1,534
TOTAL	**26,370**	**26,553**	**26,656**	**26,713**	**26,773**	**26,900**	**26,970**	**27,135**	**27,616**
Substations									
Transmission	449	475	481	470	485	495	502	503	507
Distribution	2,824	2,870	2,878	2,868	2,812	2,809	2,810	2,784	2,788
Total Substations	**3,273**	**3,345**	**3,359**	**3,338**	**3,297**	**3,304**	**3,312**	**3,287**	**3,295**

TABLE I
TRANSMISSION MILEAGE BY KV

($ in millions)	2002	2003	2004	2005	2006	2007	2008	2009
O&M								
Transmission	$140	$142	$158	$180	$195	$192	$193	$186
Distribution Substation	$27	$29	$29	$28	$29	$31	$31	$27
TOTAL	**$167**	**$171**	**$187**	**$209**	**$224**	**$223**	**$223**	**$213**
Capital								
Growth	$328	$305	$287	$308	$321	$361	$349	$365
Infrastructure	$118	$124	$171	$154	$169	$187	$230	$201
TOTAL	**$436**	**$429**	**$458**	**$462**	**$491**	**$548**	**$579**	**$566**

TABLE II
TRANSMISSION INVESTMENT BY YEAR

C. *Regional Planning*

In addition to the joint transmission planning performed among the four transmission owners in the Georgia ITS, the Southern Companies interconnect with seven other transmission owners in the SERC reliability region and with four transmission owners in the Florida Reliability Coordination Council (FRCC). The Southern Companies coordinate extensively with neighboring systems directly under the respective interchange agreements, as members of SERC, and also through the open stakeholder processes established under the OATT (Southeastern Regional Transmission Planning (SERTP) and the Southeast Inter-Regional Participation Process (SIRPP)) [3]

Through these activities, the Southern Companies have established strong interconnections with neighboring systems

[1] Department of Energy, National Electric Transmission Congestion Study, at 60-61 (December 2009).

[2] 2009 Study at 60-61 (quoting North American Electric Reliability Corporation, NERC 2009 Summer Reliability Assessment (May 2009), at 131. The NERC 2009 Summer Assessment is available at http://www.nerc.com/files/summer2009.pdf

providing the capability of simultaneously importing or exporting thousands of MWs of power via the Southern Companies' 53 tie lines and extensive transmission system. These large levels of transfer capability support both long-term bilateral deliveries and active short-term opportunity sales.

Import and export capabilities for the Balancing Area allocated to the Southern Companies are posted on the Southern Companies' OASIS website (www.weboasis.com). Values of transfer capability allocated to the other GA ITS participants can be obtained from their respective websites.

	Interface	Allocation		
		Import		Export
Jul-10	TVA	1910		1087
	Entergy	2363		1463
	Duke	532		1070
	SCEG	214		200
	SCPSA	153		252
	Florida	621		2437
	PowerSouth	590		961
	SMEPA	210		350
Dec-10	TVA	2560		1590
	Entergy	2610		2110
	Duke	1094		1085
	SCEG	344		220
	SCPSA	315		236
	Florida	1118		2563
	PowerSouth	666		1124
	SMEPA	180		350

TABLE III
RECENT SIMULTANEOUS TOTAL TRANSFER CAPABILITY (TTC) VALUES
(Southern Companies' Allocation. Does not include allocations to unaffiliated participants in the GA ITS)

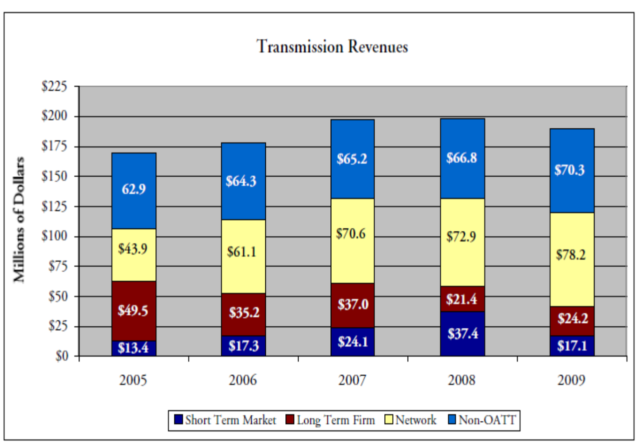


FIGURE 2. TRANSMISSION SERVICE REVENUES BY YEAR

D. *Reliability Considerations*

The Southern Companies have consistently invested in reliability, both for local load serving reliability and also for bulk system reliability. Extensive analysis is performed to meet and exceed the NERC Reliability Standards and also to identify opportunities to reduce local outage durations and frequency. Generation adequacy is assessed applying a 15% reserve margin target supported with firm transmission service for all designated network resources. Likewise, since OATT customers rely upon the dependability of the firm transmission services they purchase, the Southern Companies combine investments in transmission system upgrades needed to provide firm service with the application of operating procedures, ambient adjusted ratings, and other operating tools to minimize the occurrence of firm service curtailments. The Southern Companies have not implemented a Transmission Loading Relief (TLR) curtailment since 2004. [4]

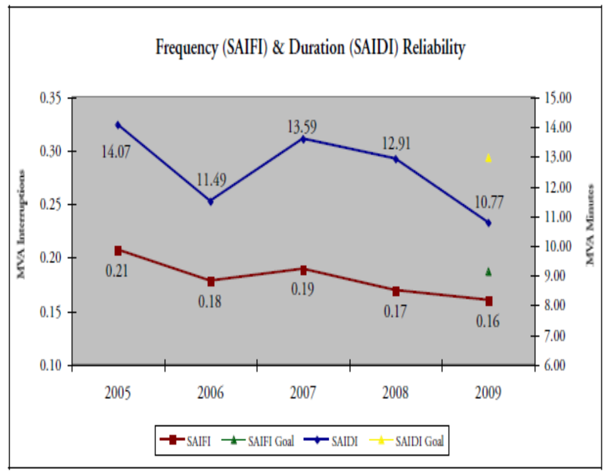


FIGURE 3. TRANSMISSION SYSTEM OUTAGE FREQUENCY AND DURATION

Other reliability considerations include coordinated distribution and transmission system reactive planning and the utilization of voltage schedules based upon Optimal Power Flow (OPF) analysis to reduce system real and reactive losses. Annual analysis is also performed to ensure a minimum 5% voltage security margin. The Southern Companies are a leader in identifying and addressing voltage, dynamic, and transient stability reliability concerns. Examples include management of Fault Induced Delayed Voltage Recovery (FIDVR) exposure [5][6], which has been addressed in the metro Atlanta area, and management of stability limits identified in two generation pockets located in the Northwest Quadrant (NWQ) and Southwest Quadrant (SWQ) portions of the service area.

Another emerging reliability consideration is the undesired resonance related to shunt capacitor banks which is arising due to customer loads becoming increasingly reactive. The Southern Companies routinely assess shunt capacitor bank locations to determine whether filtered installations are required to address resonance.

III. PLANNED EXPANSION

A. Combined Cycle Generation in Atlanta

Siting generation within load centers provides numerous benefits including enhanced power system reliability and improved environmental considerations. Supplying a major load center such as metro Atlanta from distant resources introduces numerous reliability challenges in maintaining adequate voltage support and avoiding overloads under potential contingencies. Through its integrated resource planning process, Georgia Power, working with the Georgia Public Service Commission and independent evaluators, determined that generation expansion within the Atlanta area would provide substantial reliability benefits.

In this regard, Georgia Power will replace 540 MWs of existing coal generation with three, 840 MW blocks of Combined Cycle gas generation at Plant McDonough in Atlanta. The total generation at Plant McDonough will thus increase to 2,520 MW. However, NOx emissions will be reduced by more than 90 percent, SO2 levels by more than 90 percent, and mercury emissions will essentially be eliminated using natural gas as compared to the current emissions levels of the coal-fueled plant.

From a transmission perspective, voltage support in metro Atlanta is greatly enhanced. In particular, Fault-Induced Delayed Voltage Recovery constraints associated with reactive load growth in the metro Atlanta region will be mitigated for several years, avoiding the need for over 1000 Mvars in Static Var Compensation (SVC).

To accommodate delivery of the substantial additional generation from Plant McDonough, very modest transmission upgrades were required. A new 7-mile 230 kV circuit to the Smyrna substation has been constructed, improvements will be made to two nearby substations, and various 115 kV and 230 kV lines totaling over 30 miles are being upgraded.

B. New Nuclear Generation in Georgia

Nuclear generation offers economical base load capacity with zero carbon or other combustion emissions. Georgia Power, jointly with Dalton Utilities, Municipal Electric Authority of Georgia, and Oglethorpe Power, is building 2200 MWs of nuclear generation at Plant Vogtle near Augusta, Georgia, about 150 miles from Atlanta. The plant will employ a passive core cooling system utilizing the Westinghouse AP1000 technology, designed to achieve and maintain safe shutdown conditions without operator action and without the need for ac power or pumps [7]. The Vogtle units are scheduled to be in commercial operation in 2016 and 2017, a few years after the first AP1000 units are completed in China at the Sanmen Nuclear Power Station [8].

The Vogtle units, designed to operate at about a 90% capacity factor, will reliably generate emission-free electricity 24 hours a day producing 2-3 times the energy produced by other clean resources of comparable capacity. The Vogtle units will increase fuel diversity for customers in Georgia, reducing their exposure to price volatility in natural gas markets and potential CO2 costs related to carbon regulation.

As part of the integrated resource planning process, Georgia Power, working with the other Georgia ITS participants, is constructing system upgrades to provide firm (uncongested) transmission service to coincide with the commercial operation of the new Vogtle nuclear units.

Georgia has developed a strong, flexible transmission grid as part of its long-term IRP activities. The 2200 MWs of new nuclear capacity will be integrated into the grid at a relatively low transmission expansion cost while also meeting the high reliability Final Safety Analysis Requirements (FSAR) associated with nuclear plant licensing.

A new 50-mile 500 kV line from Vogtle to the Thomson substation is being constructed and the Vogtle 500/230 kV switchyard will be expanded to accommodate interconnection of the new line and the two new units and associated reserve auxiliary transformers. A number of circuit breakers and other equipment will be upgraded to address the increased fault current at the switchyard.

C. Coal Gasification with Carbon Capture Facility in Mississippi

Mississippi Power is building a 582 MW Integrated Gasification Combined Cycle (IGCC) power plant at Kemper County, MS scheduled for commercial operation in May 2014. The facility utilizes Transport Integrated Gasification (TRIG™) technology developed by Southern Company and KBR. [9] The plant will turn low grade coal reserves (Mississippi lignite) into syngas while greatly lowering emissions of sulfur dioxide, nitrogen oxides and mercury as compared to traditional pulverized coal generation. It will also utilize carbon capture technology to reduce carbon emissions by 65%, resulting in carbon emissions equivalent to that of a similarly sized natural gas combined cycle plant.

The plant will provide clean, economical baseload capacity, support energy independence, and increase fuel diversity for Mississippi Power customers, thereby reducing exposure to price volatility in natural gas markets.

Consistent with integrated resource planning, transmission assessments were performed and included in the evaluation of the facility. Transmission upgrades will be constructed prior to 2014 to provide firm (uncongested) transmission service.

The expansion includes (57) miles of new 230 kV, (9) miles of new 115 kV, and rebuilding (24) miles of existing 115 kV transmission lines along with (3) new 230 kV switching stations, (1) new 230/115 kV substation, and the addition of a parallel 230/115 kV transformer at an existing substation. This expansion plan is anticipated to cost approximately $120M and represents a major investment in the bulk electric network by Mississippi Power Company.

IV. ANTICIPATED CHALLENGES

A. Generation Retirements and Replacement Resources

The EPA is currently developing a Maximum Achievable Control Technology (MACT) rule for coal and oil-fired electric generating units, which will likely address numerous Hazardous Air Pollutants Standards (HAPS), including mercury. A DC circuit court consent decree regarding HAPS/MACT established a schedule for the EPA to finalize the rules in late 2011, which would by law include a three year implementation period for generators to install MACT controls or discontinue operations in 2015. Because the rules have not yet been established, it is unclear today whether generating units, even those which have already installed SCRs and scrubbers, will be able to meet the new HAPS/MACT rules by 2015. Generator owners obviously would like to know the technical requirements and total cost implications of current and pending regulations prior to beginning construction on HAPS/MACT controls. Complicating generator control decisions are pending rules and potential legislation on coal combustion byproducts (ash), water, green house gasses (carbon), and other issues. Generators will base their control investment decisions on their beliefs of the total costs of all compliance requirements, not just HAPS/MACT.

From a transmission planning perspective, many potential resource scenarios could evolve in the 2015 timeframe and beyond. For this reason, Southern Companies perform scenario analysis to assess potentially unreliable system configurations and identify viable mitigation measures. For example, an RFP is currently underway in Georgia to procure additional resources that may be needed depending upon the outcome of the HAPS/MACT rules. [10]

B. Variable Generation Considerations

Southern Company conducts planning to maintain a diversified portfolio of renewable and conventional resources in serving the electrical needs of its customers. Southern Company is actively pursuing renewable resource options within its service territory such as biomass, hydro, wind, and solar along with low carbon options such as nuclear and IGCC with CCS. Imports of wind energy may also be a part of our resource portfolio in amounts that are economical in comparison to locally procured options and where the associated operating challenges can be reliably addressed.

A national 20% Renewable Energy Standard (RES) is an extremely challenging target from the perspectives of operational reliability and economic feasibility. Wind generation provides an attractive renewable option with significant amounts of capacity having been implemented at competitive costs in several regions. However, much of the wind energy produced today is available chiefly during off-peak periods when the demand for electricity is low and electricity prices are low. Absent economical storage options, low off-peak demand and associated low electricity prices will limit how much wind generation can be economically developed and how much wind energy can be produced and utilized.

Southern Company is assessing wind energy imports through numerous activities including renewable RFPs, direct interactions with developers, and regional studies with neighboring systems. Wind imports for Southern Company involve long distance transfers which are typically less economical than wind deliveries to closer markets. For example, attractive sites in the Texas panhandle may be 300-400 miles from Dallas or less, but are more than 1100 miles from Atlanta. Distance is a major factor in transmission facility costs, OATT costs, transmission losses, congestion risks, and other costs.

Significant operating challenges also exist due to the variable and chiefly off-peak production of wind energy. Operating challenges include ramping up and down to serve daily loads, regulating minute to minute to match generation and loads, providing reactive reserves and voltage support, and similar issues.

Utilizing existing transmission capacity (typically off-peak capacity) for wind energy imports may be an economical delivery mechanism for modest amounts of energy deliveries. The Southern Companies' transmission system is capable of receiving thousands of MWs of imports from a power flow perspective, and current tariffs at SPP and Entergy could enable delivery costs in the $10/MW-hour range. Southern Company is currently evaluating options in this area. In addition to greatly reduced delivery costs as compared to large scale transmission expansion (a long-distance HVDC tie alone could exceed $30/MW-hour), operating challenges are less significant as well.

Perhaps more challenging than the physical delivery (power flow) aspects of long distance imports are the operating challenges of managing the variability of wind energy outputs. Southern Companies are working to determine how much variable energy can be managed with existing generator regulating and reserve capabilities. One area of concern is that unit commitment and ramping capabilities are likely to decline nationally as smaller fossil units are retired and replaced with much larger units. For example, if four 200 MW plants are replaced by an 800 MW plant, the granularity in unit commitment is significantly reduced. Similarly, operating ranges on existing larger plants will be more constrained due to environmental controls.

Energy storage and demand-side management are additional resources to address these operating challenges. Approximately 3400 MWs of conventional and pumped storage hydro resources connected the Southern Companies system are currently deployed to support existing operating needs. Southern Company is also investigating potential additions of new storage and alternative approaches to utilizing existing storage.

C. Conclusion

Clearly, each resource decision conveys numerous operating implications. A holistic approach, such as Integrated Resource Planning, is appropriate and necessary to fully assess the impacts and inter-dependencies of resource and transmission expansion decisions. Southern Company believes that the best approach for our customers is not to focus solely on a few technologies, but rather to consider all available options in maintaining a diverse portfolio of resources, each applied in a manner to best leverage its economic and reliability contributions.

Acknowledgments

W.D.M. thanks the following individuals for their assistance in preparing this paper: David Schmidt, Jeff Burleson, Andy Tunnell, Bill Botters, Randy Cobb, Lee Taylor, Garey Rozier, John Lucas, Jeremy Bennett, and David Mohon

References

[1] North American Electric Reliability Corporation, NERC 2009 Long-Term Reliability Assessment: 2009-2018 (Oct. 2009), at 26 ("NERC 2009 Assessment"). The NERC 2009 Assessment is available at: http://www.nerc.com/files/2009_LTRA.pdf. SERC covers 560,000 square miles and has 97,256 circuit miles. NERC 2009 Assessment, at 26, 223. By way of comparison, WECC covers nearly 1.8 million square miles and has 120,532 circuit miles (of that number, the portions of WECC located in the United States have 98,030 circuit miles). NERC 2009 Assessment, at 26, 152. The other reliability councils having a larger footprint than SERC but less transmission mileage are the Northeast Power Coordinating Council, Inc. ("NPCC") (covering 1.2 million square miles and having 58,938 circuit miles, with the portions of the NPCC located in the United States having 13,638 circuit miles) and the Midwest Reliability Corporation ("MRO") (covering 1 million square miles and having 48,670, with the portions in the Unites States having 36,482 circuit miles). NERC 2009 Assessment, at 26, 197, 273.

[2] Initial Comments of Southern Company Services, Inc., FERC Docket No. AD09-8-000 (Nov. 23, 2009), at 6-7.

[3] http://southeastirpp.com, http://southeasternrtp.com

[4] See Trend Charts at http://www.nerc.com/filez/Logs/tlrlogs.html

[5] Lee Y. Taylor and Shih-Min Hsu, "Transmission Voltage Recovery Following a Fault Event in the Metro Atlanta Area," Power Engineering Society Summer Meeting, 2000 IEEE.

[6] Lee Y. Taylor, Robert A. Jones, and S. Mark Halpin, "Development of Load Models for Fault Induced Delayed Voltage Recovery Dynamic Studies," Power Engineering Society Summer Meeting, 2008 IEEE.

[7] http://www.ap1000.westinghousenuclear.com/ap1000_safety.html

[8] http://en.wikipedia.org/wiki/Sanmen_Nuclear_Power_Plant

[9] http://www.mississippipower.com/kemper/TRIGTechnology.asp

[10] https://www.gpscie.com/_gpscie/gpsc_register1.asp

ATTACHMENT K
The Southeastern Regional Transmission Planning Process

The Transmission Provider participates in the Southeastern Regional Transmission Planning Process ("SERTP") described herein and on the Regional Planning Website, a link to which is found on the Transmission Provider's OASIS. The other transmission providers and owners that participate in this Southeastern Regional Transmission Planning Process are identified on the Regional Planning Website ("Sponsors").[1] This Southeastern Regional Transmission Planning Process provides a coordinated, open and transparent planning process between the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers and other interested parties, including the coordination of such planning with interconnected systems within the region, to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and nondiscriminatory basis. The Transmission Provider's coordinated, open and transparent planning process is hereby provided in this Attachment K, with additional materials provided on the Regional Planning Website.

[1] The Transmission Provider notes that while this Attachment K discusses the Transmission Provider largely effectuating the activities of the Southeastern Regional Transmission Planning Process that are discussed herein, the Transmission Provider expects that the other Sponsors will also sponsor those activities. For example, while this Attachment K discusses the Transmission Provider hosting the Annual Transmission Planning Meetings, the Transmission Provider expects that it will be co-hosting such meetings with the other Sponsors. Accordingly, many of the duties described herein as being performed by the Transmission Provider may be performed in conjunction with one or more other Sponsors or may be performed entirely by one or more other Sponsors. Likewise, while this Attachment K discusses the transmission expansion plan of the Transmission Provider, the Transmission Provider expects that transmission expansion plans of the other Sponsors shall also be discussed, particularly since, at times, a single transmission expansion plan may be common to all Sponsors. To the extent that this Attachment K makes statements that might be construed to imply establishing duties or obligations upon other Sponsors, no such duty or obligation is intended. Rather, such statements are intended to only mean that it is the Transmission Provider's expectation that other Sponsors will engage in such activities. Accordingly, this Attachment K only establishes the duties and obligations of the Transmission Provider and the means by which Stakeholders may interact with the Transmission Provider through the Southeastern Regional Transmission Planning Process described herein.

Local Transmission Planning

The Transmission Provider has established the SERTP as its coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider plans its transmission system to reliably meet the needs of its transmission customers on a least-cost, reliable basis in accordance with applicable requirements of federal and state public utility laws and regulations. The Transmission Provider incorporates into its transmission plans the needs and results of the integrated resource planning activities conducted within each of its applicable state jurisdictions pursuant to its applicable duty to serve obligations. In accordance with the foregoing, its contractual requirements, and the requirements of NERC Reliability Standards, the Transmission Provider conducts comprehensive reliability assessments and thoroughly coordinates with neighboring and/or affected transmission providers.

As provided below, through its participation in the SERTP, the Transmission Provider's local planning process satisfies the following nine principles, as defined in Order No. 890: coordination, openness, transparency, information exchange, comparability,[2] dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. This planning process also addresses at Section 9 the requirement to provide a mechanism for the recovery and allocation of planning costs consistent with Order No. 890. This planning process also includes at Section 10 the procedures and mechanisms for considering transmission needs

[2]The Transmission Provider is committed to providing comparable and non-discriminatory transmission service. As such, comparability is not separately addressed in a stand-alone section of this Attachment K but instead permeates the Southeastern Regional Transmission Process described in this Attachment K.

driven by Public Policy Requirements consistent with Order No. 1000. As provided below, the SERTP includes sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers for Attachment K purposes, which is set forth in Section 1 of this Attachment K;

(ii) The notice procedures and anticipated frequency of meetings; which is set forth in Sections 1 and 2 of this Attachment K;

(iii) The Transmission Provider's transmission planning methodology, criteria, and processes, which are set forth in Section 3 of this Attachment K;

(iv) The method of disclosure of transmission planning criteria, assumptions and underlying data, which is set forth in Sections 2 and 3 of this Attachment K;

(v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider, which is set forth in Section 4 of this Attachment K;

(vi) The dispute resolution process, which is set forth in Section 5 of this Attachment K;

(vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources, which is set forth in Section 7 of this Attachment K;

(viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000, which are set forth in Section 10 of this Attachment K; and

(ix) The relevant cost allocation method or methods, which is set forth in Section 8 of this Attachment K.

Regional Transmission Planning

The Transmission Provider participates in the SERTP through which transmission facilities and non-transmission alternatives may be proposed and evaluated. This regional transmission planning process develops a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region for purposes of Order No. 1000. This regional transmission planning process is consistent with the provision of Commission-jurisdictional services at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order No. 1000.

This regional transmission planning process satisfies the following seven principles, as set out and explained in Order Nos. 890 and 1000: coordination, openness, transparency, information exchange, comparability,[3] dispute resolution, and economic planning studies. This regional transmission planning process includes at Section 10 the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. This regional transmission planning process provides at Section 9 a mechanism for the recovery and allocation of planning costs consistent with Order No. 890. This regional transmission planning process includes at Section 12 a clear enrollment process for public and non-public utility transmission providers that make the choice to become part of a transmission planning region for purposes of regional cost allocation. This regional transmission planning process subjects enrollees to cost allocation if they are found to be beneficiaries of new transmission facilities selected in the regional transmission plan for purposes of cost allocation.

[3]The Transmission Provider is committed to providing comparable and non-discriminatory transmission service. As such, comparability is not separately addressed in a stand-alone section of this Attachment K but instead permeates the Southeastern Regional Transmission Process described in this Attachment K.

The list of enrolled entities to the SERTP is posted on the Regional Planning Website. The relevant cost allocation method or methods that satisfy the six regional cost allocation principles set forth in Order No. 1000 are described in Sections 16-17 of this Attachment K. Nothing in this regional transmission planning process includes an unduly discriminatory or preferential process for transmission project submission and selection. As provided below, the SERTP includes sufficient detail to enable Transmission Customers to understand:

(i) The process for enrollment and terminating enrollment in the SERTP, which is set forth in Section 12 of this Attachment K;

(ii) The process for consulting with customers, which is set forth in Section 1 of this Attachment K;

(iii) The notice procedures and anticipated frequency of meetings, which is set forth in Sections 1 and 2 of this Attachment K;

(iv) The Transmission Provider's transmission planning methodology, criteria, and processes, which are set forth in Section 3 of this Attachment K;

(v) The method of disclosure of transmission planning criteria, assumptions and underlying data, which is set forth in Sections 2 and 3 of this Attachment K;

(vi) The obligations of and methods for transmission customers to submit data, which are set forth in Section 4 of this Attachment K;

(vii) The process for submission of data by nonincumbent developers of transmission projects that wish to participate in the transmission planning process and seek regional cost allocation for purposes of Order No. 1000, which is set forth in Sections 13-21 of this Attachment K;

(viii) The process for submission of data by merchant transmission developers that wish to participate in the transmission planning process, which is set forth in Section 11 of this Attachment K;

(ix) The dispute resolution process, which is set forth in Section 5 of this Attachment K;

(x) The study procedures for economic upgrades to address congestion or the integration of new resources, which is set forth in Section 7 of this Attachment K;

(xi) The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000, which are set forth in Section 10 of this Attachment K; and

(xii) The relevant cost allocation method or methods satisfying the six regional cost allocation principles set forth in Order No. 1000, which is set forth at Sections 16-17.

ORDER NO. 890 TRANSMISSION PLANNING PRINCIPLES

1. Coordination

1.1 General: The Southeastern Regional Transmission Planning Process is designed to eliminate the potential for undue discrimination in planning by establishing appropriate lines of communication between the Transmission Provider, its transmission-providing neighbors, affected state authorities, Transmission Customers, and other Stakeholders regarding transmission planning issues.

1.2 Meeting Structure: Each calendar year, the Southeastern Regional Transmission Planning Process will generally conduct and facilitate four (4) meetings ("Annual Transmission Planning Meetings") that are open to all Stakeholders. However, the number of Annual Transmission Planning Meetings, or duration of any particular meeting, may be adjusted by announcement upon the Regional

Planning Website, provided that any decision to reduce the number of Annual Transmission Planning Meetings must first be approved by the Sponsors and by the Regional Planning Stakeholders' Group ("RPSG"). These meetings can be done in person, through phone conferences, or through other telecommunications or technical means that may be available. The details regarding any such meeting will be posted on the Regional Planning Website, with a projected meeting schedule for a calendar year being posted on the Regional Planning Website on or before December 31st of the prior calendar year, with firm dates for all Annual Transmission Planning Meetings being posted at least 60 calendar days prior to a particular meeting. The general structure and purpose of these four (4) meetings will be as follows:

1.2.1 First RPSG Meeting and Interactive Training Session: At this meeting, which will be held in the first quarter of each calendar year, the RPSG will be formed for purposes of that year. In addition, the Transmission Provider will meet with the RPSG and any other interested Stakeholders for the purposes of allowing the RPSG to select up to five (5) Stakeholder requested Economic Planning Studies that they would like to have studied by the Transmission Provider and the Sponsors. At this meeting, the Transmission Provider will work with the RPSG to assist the RPSG in formulating these Economic Planning Study requests. Requests that are inter-regional in nature will be addressed in the Southeast Inter-Regional Participation Process. The Transmission Provider will also conduct an interactive training session regarding its transmission planning for all interested Stakeholders. This session will explain and discuss the underlying methodology and criteria that will be utilized to develop the transmission expansion plan[4] before that methodology and criteria are finalized for purposes of the development of that year's transmission expansion plan (*i.e.*, the expansion plan that will be implemented the following calendar year).[5] Stakeholders may submit comments to the Transmission Provider regarding the Transmission Provider's criteria and methodology during the discussion at the meeting or within ten (10) business days after the meeting, and the Transmission Provider will consider such comments. Depending upon the major transmission planning issues presented at that time, the Transmission Provider will provide various technical experts that will lead the discussion of pertinent transmission planning topics, respond to Stakeholder questions, and provide technical guidance regarding transmission planning matters. It is foreseeable that it may prove appropriate to shorten the training sessions as Stakeholders become increasingly knowledgeable regarding the Transmission Provider's transmission planning process and no longer need detailed training in this regard.

---

[4]As indicated *infra* at footnote 1, references in this Attachment K to a transmission "plan," "planning," or "plans" should be construed in the singular or plural as may be appropriate in a particular instance. Likewise, the reference to a plan or plans may, depending upon the circumstance, be a reference to a regional transmission plan required for purposes of Order No. 1000. Moreover, the iterative nature of transmission planning bears emphasis, with underlying assumptions, needs, and data inputs continually changing to reflect market decisions, load service requirements, and other developments. A transmission plan, thus, only represents the status of transmission planning when the plan was prepared.

[5]A transmission expansion plan completed during one calendar year (and presented to Stakeholders at that calendar year's Annual Transmission Planning Summit) is implemented the following calendar year. For example, the transmission expansion plan developed during 2009 and presented at the 2009 Annual Transmission Planning Summit is for the 2010 calendar year.

The Transmission Provider will also address transmission planning issues that the Stakeholders may raise.

1.2.2 **Preliminary Expansion Plan Meeting:** During the second quarter of each calendar year, the Transmission Provider will meet with all interested Stakeholders to explain and discuss: the Transmission Provider's preliminary transmission expansion plan, which is also input into that year's SERC (or other applicable NERC region's) regional model; internal model updating and any other then-current coordination study activities with the transmission providers in the Florida Reliability Coordinating Council ("FRCC"); and any *ad hoc* coordination study activities that might be occurring. These preliminary transmission expansion plan, internal model updating, and coordination study activities will be described to the Stakeholders, with this meeting providing them an opportunity to supply their input and feedback, including the transmission plan/enhancement alternatives that the Stakeholders would like the Transmission Provider and the Sponsors to consider. In addition, the Transmission Provider will address transmission planning issues that the Stakeholders may raise and otherwise discuss with Stakeholders developments as part of the SERC (or other applicable NERC region's) reliability assessment process.

1.2.3 **Second RPSG Meeting:** During the third quarter of each calendar year, the Transmission Provider will meet with the RPSG and any other interested Stakeholders to report the preliminary results for the Economic

Planning Studies requested by the RPSG at the First RPSG Meeting and Interactive Training Session. Study results that are inter-regional in nature will be reported to the RPSG and interested Stakeholders as they become available from the Southeast Inter-Regional Planning Participation Process. This meeting will give the RPSG an opportunity to provide input and feedback regarding those preliminary results, including alternatives for possible transmission solutions that have been identified. At this meeting, the Transmission Provider shall provide feedback to the Stakeholders regarding transmission expansion plan alternatives that the Stakeholders may have provided at the Preliminary Expansion Plan Meeting, or within a designated time following that meeting. The Transmission Provider will also discuss with the Stakeholders the results of the SERC (or other applicable NERC region's) regional model development for that year (with the Transmission Provider's input into that model being its ten (10) year transmission expansion plan); any on-going coordination study activities with the FRCC transmission providers; and any *ad hoc* coordination study activities. In addition, the Transmission Provider will address transmission planning issues that the Stakeholders may raise.

1.2.4 **Annual Transmission Planning Summit and Assumptions Input Meeting:** During the fourth quarter of each calendar year, the Transmission Provider will host the annual Transmission Planning Summit and Assumptions Input Meeting.

1.2.4.1 **Annual Transmission Planning Summit:** At the Annual Transmission Planning Summit aspect of the Annual Transmission Planning Summit and Assumptions Input Meeting, the Transmission Provider will present the final results for the Economic Planning Studies. The results for such studies that are inter-regional in nature will be reported to the RPSG and interested Stakeholders as they become available from the Southeast Inter-Regional Planning Participation Process. The Transmission Provider will also provide an overview of the ten (10) year transmission expansion plan, the results of that year's coordination study activities with the FRCC transmission providers, and the results of any *ad hoc* coordination study activities. The Transmission Provider will also provide an overview of the regional transmission plan for Order No. 1000 purposes, which should include the ten (10) year transmission expansion plan of the Transmission Provider. In addition, the Transmission Provider will address transmission planning issues that the Stakeholders may raise.

1.2.4.2 **Assumptions Input Session:** The Assumptions Input Session aspect of the Annual Transmission Planning Summit and Assumptions Input Meeting will take place following the annual Transmission Planning Summit and will provide an open forum for discussion with, and input from, the Stakeholders regarding:

the data gathering and transmission model assumptions that will be used for the development of the Transmission Provider's following year's ten (10) year transmission expansion plan, which includes the Transmission Provider's input, to the extent applicable, into that year's SERC regional model development; internal model updating and any other then-current coordination study activities with the transmission providers in the Florida Reliability Coordinating Council ("FRCC"); and any *ad hoc* coordination study activities that might be occurring. This meeting may also serve to address miscellaneous transmission planning issues, such as reviewing the previous year's regional planning process, and to address specific transmission planning issues that may be raised by Stakeholders.

1.3 Committee Structure – the RPSG: To facilitate focused interactions and dialogue between the Transmission Provider and the Stakeholders regarding transmission planning, and to facilitate the development of the Economic Planning Studies, the RPSG was formed in March 2007. The RPSG has two primary purposes. First, the RPSG is charged with determining and proposing up to five (5) Economic Planning Studies on an annual basis and should consider clustering similar Economic Planning Study requests. The RPSG is also encouraged to coordinate with stakeholder groups in the area covered by the Southeast Inter-Regional Participation Process regarding requests for Economic Planning Studies that are inter-regional in nature. Second, the RPSG serves as the representative in interactions with the Transmission Provider and Sponsors for the eight (8) industry sectors identified below.

1.3.1 RPSG Sector Representation: The Stakeholders are organized into the following eight (8) sectors for voting purposes within the RPSG:

(1) Transmission Owners/Operators[6]

(2) Transmission Service Customers

(3) Cooperative Utilities

(4) Municipal Utilities

(5) Power Marketers

(6) Generation Owners/Developers

(7) ISO/RTOs

(8) Demand Side Management/Demand Side Response

1.3.2 Sector Representation Requirements: Representation within each sector is limited to two members, with the total membership within the RPSG being capped at 16 members ("Sector Members"). The Sector Members, each of whom must be a Stakeholder, are elected by Stakeholders, as discussed below. A single company, and all of its affiliates, subsidiaries, and parent company, is limited to participating in a single sector.

1.3.3 Annual Reformulation: The RPSG will be reformed annually at each First RPSG Meeting and Interactive Training Session

[6] The Sponsors will not have a vote within the Transmission Owners/Operators sector, although they (or their affiliates, subsidiaries or parent company) shall have the right to participate in other sectors.

discussed in Section 1.2.1. Specifically, the Sector Members will be elected for a term of approximately one year that will terminate upon the convening of the following year's First RPSG Meeting and Interactive Training Session. Sector Members shall be elected by the Stakeholders physically present at the First RPSG Meeting and Interactive Training Session (voting by sector for the respective Sector Members). If elected, Sector Members may serve consecutive, one-year terms, and there is no limit on the number of terms that a Sector Member may serve.

1.3.4 Simple Majority Voting: RPSG decision-making that will be recognized by the Transmission Provider for purposes of this Attachment K shall be those authorized by a simple majority vote by the then-current Sector Members, with voting by proxy being permitted for a Sector Member that is unable to attend a particular meeting. The Transmission Provider will notify the RPSG of the matters upon which an RPSG vote is required and will use reasonable efforts to identify upon the Regional Planning Website the matters for which an RPSG decision by simple majority vote is required prior to the vote, recognizing that developments might occur at a particular Annual Transmission Planning Meeting for which an RPSG vote is required but that could not be reasonably foreseen in advance. If the RPSG is unable to achieve a majority vote, or should the RPSG miss any of the deadlines prescribed herein or clearly identified on the Regional Planning Website and/or at a particular meeting to take any action, then the Transmission Provider will be relieved of any obligation that is associated with such RPSG action.

1.3.5 RPSG Guidelines/Protocols: The RPSG is a self-governing entity subject to the following requirements that may not be altered absent an appropriate filing with the Commission to amend this aspect of the Tariff: (i) the RPSG shall consist of the above-specified eight (8) sectors; (ii) each company, its affiliates, subsidiaries, and parent company, may only participate in a single sector; (iii) the RPSG shall be reformed annually, with the Sector Members serving terms of a single year; and (iv) RPSG decision-making shall be by a simple majority vote (*i.e.*, more than 50%) by the Sector Members, with voting by written proxy being recognized for a Sector Member unable to attend a particular meeting. There are no formal incorporating documents for the RPSG, nor are there formal agreements between the RPSG and the Transmission Provider. As a self-governing entity, to the extent that the RPSG desires to adopt other internal rules and/or protocols, or establish subcommittees or other structures, it may do so provided that any such rule, protocol, etc., does not conflict with or otherwise impede the foregoing requirements or other aspects of the Tariff. Any such additional action by the RPSG shall not impose additional burdens upon the Transmission Provider unless it agrees in advance to such in writing, and the costs of any such action shall not be borne or otherwise imposed upon the Transmission Provider unless the Transmission Provider agrees in advance to such in writing.

1.4 The Role of the Transmission Provider in Coordinating the Activities of the Southeastern Regional Transmission Planning Process Meetings and of the Functions of the RPSG: The Transmission Provider will host and conduct the above-described Annual Transmission Planning Meetings with Stakeholders.[7]

1.5 Procedures Used to Notice Meetings and Other Planning-Related Communications: Meetings notices, data, stakeholder questions, reports, announcements, registration for inclusion in distribution lists, means for being certified to receive Critical Energy Infrastructure Information ("CEII"), and other transmission planning-related information will be posted on the Regional Planning Website. Stakeholders will also be provided notice regarding the annual meetings by e-mail messages (if they have appropriately registered on the Regional Planning Website to be so notified). Accordingly, interested Stakeholders may register on the Regional Planning Website to be included in e-mail distribution lists ("Registered Stakeholder"). For purposes of clarification, a

[7] As previously discussed, the Transmission Provider expects that the other Sponsors will also be hosts and sponsors of these activities.

Stakeholder does not have to have received certification to access CEII in order to be a Registered Stakeholder.

1.6 Procedures to Obtain CEII Information: For access to information considered to be CEII, there will be a password protected area that contains such CEII information. Any Stakeholder may seek certification to have access to this CEII data area.

1.7 The Regional Planning Website: The Regional Planning Website will contain information regarding the Southeastern Regional Transmission Planning Process, including:

- Notice procedures and e-mail addresses for contacting the Sponsors and for questions;
- A calendar of meetings and other significant events, such as release of draft reports, final reports, data, etc.;
- A registration page that allows Stakeholders to register to be placed upon an e-mail distribution list to receive meetings notices and other announcements electronically; and
- The form in which meetings will occur (*i.e.*, in person, teleconference, webinar, *etc*.).

2. Openness

2.1 General: The Annual Transmission Planning Meetings, whether consisting of in-person meetings, conference calls, or other communicative mediums, will be open to all Stakeholders. The Regional Planning Website will provide announcements of upcoming events, with Stakeholders being notified regarding the Annual Transmission Planning Meetings by such postings. In addition, Registered Stakeholders will also be notified by e-mail messages. Should any of the Annual Transmission Planning Meetings become too large or otherwise become unmanageable for the intended purpose(s), smaller breakout meetings may be utilized.

2.2 Links to OASIS: In addition to open meetings, the publicly available information, CEII-secured information (the latter of which is available to any Stakeholder certified to receive CEII), and certain confidential non-CEII information (as set forth below) shall be made available on the Regional Planning Website, a link to which is found on the Transmission Provider's OASIS website, so as to further facilitate the availability of this transmission planning information on an open and comparable basis.

2.3 CEII Information

2.3.1 Criteria and Description of CEII: The Commission has defined CEII as being specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that:

1. Relates details about the production, generation, transmission, or distribution of energy;

2. Could be useful to a person planning an attack on critical infrastructure;

3. Is exempt from mandatory disclosure under the Freedom of Information Act; and

4. Does not simply give the general location of the critical infrastructure.

2.3.2 Secured Access to CEII Data: The Regional Planning Website will have a secured area containing the CEII data involved in the Southeastern Regional Transmission Planning Process that will be password accessible to Stakeholders that have been certified to be eligible to receive CEII data.

For CEII data involved in the Southeastern Regional Transmission Planning Process that did not originate with the Transmission Provider, the duty is incumbent upon the entity that submitted the CEII data to have clearly marked it as CEII.

2.3.3 CEII Certification: In order for a Stakeholder to be certified and be eligible for access to the CEII data involved in the Southeastern Regional Transmission Planning Process, the Stakeholder must follow the CEII certification procedures posted on the Regional Planning Website (*e.g.*, authorize background checks and execute the SERTP CEII Confidentiality Agreement posted on the Regional Planning Website). The Transmission Provider reserves the discretionary right to waive the certification process, in whole or in part, for anyone that the Transmission Provider deems appropriate to receive CEII information. The Transmission Provider also reserves the discretionary right to reject a request for CEII; upon such rejection, the requestor may pursue the dispute resolution procedures of Section 5.

2.3.4 Discussions of CEII Data at the Annual Transmission Planning Meetings: While the Annual Transmission Planning Meetings are open to all Stakeholders, if CEII information is to be discussed during a portion of such a meeting, those discussions will be limited to being only with those Stakeholders who have been certified eligible to have access to CEII information, with the Transmission Provider reserving the discretionary right at such meeting to certify a Stakeholder as being eligible if the Transmission Provider deems it appropriate to do so.

2.4 Other Sponsor- and Stakeholder- Submitted Confidential Information: The other Sponsors and Stakeholders that provide information to the Transmission Provider that foreseeably could implicate transmission planning should expect that such information will be made publicly available on the Regional Planning Website or may otherwise be provided to Stakeholders in accordance with the terms of this Attachment K. Should another Sponsor or Stakeholder consider any such information to be CEII, it shall clearly mark that information as CEII and bring that classification to the Transmission Provider's attention at, or prior to, submittal. Should another Sponsor or Stakeholder consider any information to be submitted to the Transmission Provider to otherwise be confidential (*e.g.*, competitively sensitive), it shall clearly mark that information as such and notify the Transmission Provider in writing at, or prior to, submittal, recognizing that any such designation shall not result in any material delay in the development of the transmission expansion plan or any other transmission plan that the Transmission Provider (in whole or in part) is required to produce.

2.5 Procedures to Obtain Confidential Non-CEII Information

2.5.1 The Transmission Provider shall make all reasonable efforts to preserve the confidentiality of information in accordance with the provisions of the Tariff, the requirements of (and/or agreements with) NERC, the requirements of (and/or agreements with) SERC or other applicable NERC region, the provisions of any agreements with the other Sponsors and/or with the sponsors of the Southeast Inter-Regional Participation Process ("SIRPP"), and/or in accordance with any other contractual or legal confidentiality requirements.

2.5.2 [RESERVED]

2.5.3 [RESERVED]

2.5.4 Without limiting the applicability of Section 2.5.1, to the extent competitively sensitive and/or otherwise confidential information (other than information that is confidential solely due to its being CEII) is provided in the transmission planning process and is needed to participate in the transmission planning process and to replicate transmission planning studies, it will be made available to those Stakeholders who have executed the SERTP Non-CEII Confidentiality Agreement (which agreement is posted on the Regional Planning Website). Importantly, if information should prove to contain both competitively sensitive/otherwise confidential information and CEII, then the requirements of both Section 2.3 and Section 2.5 would apply.

2.5.5 Other transmission planning information shall be posted on the Regional Planning Website and may be password protected, as appropriate.

3. Transparency

3.1 General: Through the Annual Transmission Planning Meetings and postings made on the Regional Planning Website, the Transmission Provider will disclose to its Transmission Customers and other Stakeholders the basic criteria, assumptions, and data that underlie its transmission system plan, as well as information regarding the status of upgrades identified in the transmission plan. The process for notifying stakeholders of changes or updates in the data bases used for transmission planning shall be through the Annual Transmission Planning Meetings and/or by postings on the Regional Planning Website.

3.2 The Availability of the Basic Methodology, Criteria, and Process the Transmission Provider Uses to Develop its Transmission Plan: In an effort to enable Stakeholders to replicate the results of the Transmission Provider's transmission planning studies, and thereby reduce the incidences of after-the-fact disputes regarding whether transmission planning has been conducted in an unduly discriminatory fashion, the Transmission Provider will provide the following information, or links thereto, on the Regional Planning Website:

(1) The Electric Reliability Organization and Regional Entity reliability standards that the Transmission Provider utilizes, and complies with, in performing transmission planning.

(2) The Transmission Provider's internal policies, criteria, and guidelines that it utilizes in performing transmission planning.

(3) Current software titles and version numbers used for transmission analyses by the Transmission Provider.

Any additional information necessary to replicate the results of the Transmission Provider's planning studies will be provided in accordance with, and subject to, the CEII and confidentiality provisions specified in this Attachment K and Exhibit K-2.

3.3 Additional Transmission Planning-Related Information: In an effort to facilitate the Stakeholders' understanding of the Transmission System, the Transmission Provider will also post additional transmission planning-related information that it deems appropriate on the Regional Planning Website.

3.4 Additional Transmission Planning Business Practice Information: In an effort to facilitate the Stakeholders' understanding of the Business Practices related to Transmission Planning, the Transmission Provider will also post the following information on the Regional Planning Website:

(1) Means for contacting the Transmission Provider.

(2) Procedures for submittal of questions regarding transmission planning to the Transmission Provider (in general, questions of a non-immediate nature will be collected and addressed through the Annual Transmission Planning Meeting process).

(3) Instructions for how Stakeholders may obtain transmission base cases and other underlying data used for transmission planning.

(4) Means for Transmission Customers having Service Agreements for Network Integration Transmission Service to provide load and resource assumptions to the Transmission Provider; provided that if there are specific means defined in a Transmission Customer's Service Agreement for Network Integration Transmission Service ("NITSA") or its corresponding Network Operating Agreement ("NOA"), then the NITSA or NOA shall control.

(5) Means for Transmission Customers having Long-Term Service Agreements for Point-To-Point Transmission Service to provide to the Transmission Provider projections of their need for service over the planning horizon (including any potential rollover periods, if applicable), including transmission capacity, duration, receipt and delivery points, likely redirects, and resource assumptions; provided that if there are specific means defined in a Transmission Customer's Long-Term Transmission Service Agreement for Point-To-Point Transmission Service, then the Service Agreement shall control.

3.5 Transparency Provided Through the Annual Transmission Planning Meetings

3.5.1 The First RPSG Meeting and Interactive Training Session

3.5.1.1 An Interactive Training Session Regarding the Transmission Provider's Transmission Planning Methodologies and Criteria: As discussed in (and subject to) Section 1.2.1, at the First RPSG Meeting and Interactive Training Session, the Transmission Provider will, among other things, conduct an interactive, training and input session for the Stakeholders regarding the methodologies and criteria that the Transmission Provider utilizes in conducting its transmission planning analyses. The purpose of these training and interactive sessions is to facilitate the Stakeholders' ability to replicate transmission planning study results to those of the Transmission Provider.

3.5.1.2 Presentation and Explanation of Underlying Transmission Planning Study Methodologies: During the training session in the First RPSG Meeting and Interactive Training Session, the Transmission Provider will present and explain its transmission study methodologies. While not all of the following methodologies may be addressed at any single meeting, these presentations may include explanations of the methodologies for the following types of studies:

1. Steady state thermal analysis.
2. Steady state voltage analysis.
3. Stability analysis.
4. Short-circuit analysis.
5. Nuclear plant off-site power requirements.
6. Interface analysis (*i.e.*, import and export capability).

3.5.2 Presentation of Preliminary Modeling Assumptions: At the Annual Transmission Planning Summit, the Transmission Provider will also provide to the Stakeholders its preliminary modeling assumptions for the development of the Transmission Provider’s following year’s ten (10) year transmission expansion plan. This information will be made available on the Regional Planning Website, with CEII information being secured by password access. The preliminary modeling assumptions that will be provided may include:

1. Study case definitions, including load levels studied and planning horizon information.
2. Resource assumptions, including on-system and off-system supplies for current and future native load and network customer needs.
3. Planned resource retirements.
4. Renewable resources under consideration.
5. Demand side options under consideration.
6. Long-term firm transmission service agreements.
7. Current TRM and CBM values.

3.5.3 The Transmission Expansion Review and Input Process: The Annual Transmission Planning Meetings will provide an interactive process over a calendar year for the Stakeholders to receive information and updates, as well as to provide input, regarding the Transmission Provider's development of its transmission expansion plan. This dynamic process will generally be provided as follows:

1. At the Annual Transmission Planning Summit and Assumptions Input Meeting, the Transmission Provider will describe and explain to the Stakeholders the database assumptions for the ten (10) year transmission expansion plan that will be developed during the upcoming year. The Stakeholders will be allowed to provide input

regarding the ten (10) year transmission expansion plan assumptions.

2. At the First RPSG Meeting and Interactive Training Session, the Transmission Provider will provide interactive training to the Stakeholders regarding the underlying criteria and methodologies utilized to develop the transmission expansion plan. The databases utilized by the Transmission Provider will be posted on the secured area of the Regional Planning Website.

3. To the extent that Stakeholders have transmission expansion plan/enhancement alternatives that they would like for the Transmission Provider and other Sponsors to consider, the Stakeholders shall perform analysis prior to, and provide any such analysis at, the Preliminary Expansion Plan Meeting. At the Preliminary Expansion Plan Meeting, the Transmission Provider will present its preliminary transmission expansion plan for the current ten (10) year planning horizon. The Transmission Provider and Stakeholders will engage in interactive expansion plan discussions regarding this preliminary analysis. This preliminary transmission expansion plan will be posted on the secure/CEII area of the Regional Planning Website at least 10 calendar days prior to the Preliminary Expansion Plan meeting.

4. The transmission expansion plan/enhancement alternatives suggested by the Stakeholders will be considered by the

Transmission Provider for possible inclusion in the transmission expansion plan. When evaluating such proposed alternatives, the Transmission Provider will, from a transmission planning perspective, take into account factors such as, but not limited to, the proposed alternatives' impacts on reliability, relative economics, effectiveness of performance, impact on transmission service (and/or cost of transmission service) to other customers and on third-party systems, project feasibility/viability and lead time to install.

5. At the Second RPSG Meeting, the Transmission Provider will report to the Stakeholders regarding the suggestions/alternatives suggested by the Stakeholders at the Preliminary Expansion Plan Meeting. The then-current version of the transmission expansion plan will be posted on the secure/CEII area of the regional planning website at least 10 calendar days prior to the Second RPSG Meeting.

6. At the Annual Transmission Planning Summit, the ten (10) year transmission expansion plan that will be implemented the following year will be presented to the Stakeholders. The Transmission Planning Summit presentations and the (10) year transmission expansion plan will be posted on the Regional Planning Website at least 10 calendar days prior to the Annual Transmission Planning Summit.

3.5.4 Flowchart Diagramming the Steps of the Southeastern Regional Transmission Planning Process: A flowchart diagramming the Southeastern Regional Transmission Planning Process, as well as providing the general timelines and milestones for the performance of the reliability planning activities described in Section 6 to this Attachment K, is provided in Exhibit K-3.

4. Information Exchange

4.1 General: Transmission Customers having Service Agreements for Network Integration Transmission Service are required to submit information on their projected loads and resources on a comparable basis (*e.g.*, planning horizon and format) as used by transmission providers in planning for their native load. Transmission Customers having Service Agreements for Point-To-Point Transmission Service are required to submit any projections they have a need for service over the planning horizon and at what receipt and delivery points. Interconnection Customers having Interconnection Agreements under the Tariff are required to submit projected changes to their generating facility that could impact the Transmission Provider's performance of transmission planning studies. The purpose of this information that is provided by each class of customers is to facilitate the Transmission Provider's transmission planning process, with the September 1 due date of these data submissions by customers being timed to facilitate the Transmission Provider's development of its databases and model building for the following year's ten (10) year transmission expansion plan.

4.2 **Network Integration Transmission Service Customers:** By September 1 of each year, each Transmission Customer having Service Agreement[s] for Network Integration Transmission Service shall provide to the Transmission Provider an annual update of that Transmission Customer's Network Load and Network Resource forecasts for the following ten (10) years consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff.

4.3 **Point-to-Point Transmission Service Customers:** By September 1 of each year, each Transmission Customers having Service Agreement[s] for long-term Firm Point-To-Point Transmission Service shall provide to the Transmission Provider usage projections for the term of service. Those projections shall include any projected redirects of that transmission service, and any projected resells or reassignments of the underlying transmission capacity. In addition, should the Transmission Customer have rollover rights associated with any such service agreement, the Transmission Customer shall also provide non-binding usage projections of any such rollover rights.

4.4 **Demand Resource Projects:** The Transmission Provider expects that Transmission Customers having Service Agreements for Network Integration Transmission Service that have demand resource assets will appropriately reflect those assets in those customers' load projections. Should a Stakeholder have a demand resource asset that is not associated with such load projections that the Stakeholder would like to have considered for purposes of the transmission expansion plan, then the Stakeholder shall provide the necessary information *(e.g.*

technical and operational characteristics, affected loads, cost, performance, lead time to install) in order for the Transmission Provider to consider such demand response resource comparably with other alternatives. The Stakeholder shall provide this information to the Transmission Provider by the Annual Transmission Planning Summit and Assumptions Input Meeting of the year prior to the implementation of the pertinent ten (10) year transmission expansion plan, and the Stakeholder should then continue to participate in this Southeastern Regional Transmission Planning Process. To the extent similarly situated, the Transmission Provider shall treat such Stakeholder submitted demand resource projects on a comparable basis for transmission planning purposes.

4.5 Interconnection Customers: By September 1 of each year, each Interconnection Customer having an Interconnection Agreement[s] under the Tariff shall provide to the Transmission Provider annual updates of that Interconnection Customer's planned addition or upgrades (including status and expected in-service date), planned retirements, and environmental restrictions.

4.6 Notice of Material Change: Transmission Customers and Interconnection Customers shall provide the Transmission Provider with timely written notice of material changes in any information previously provided related to any such customer's load, resources, or other aspects of its facilities, operations, or conditions of service materially affecting the Transmission Provider's ability to provide transmission service or materially affecting the Transmission System.

5. Dispute Resolution

5.1 Negotiation: Any substantive or procedural dispute between the Transmission Provider and one or more Stakeholders (collectively, the "Parties") that arises from the Attachment K transmission planning process generally shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the pertinent Stakeholder(s) for resolution on an informal basis as promptly as practicable. Should the dispute also involve one or more other Sponsors of this Southeastern Regional Transmission Planning Process or other Participating Transmission Owners of the Southeast Inter-Regional Participation Process, then such entity(ies) shall have the right to be included in "Parties" for purposes of this section and for purposes of that dispute, and any such entity shall also include a designated senior representative in the above discussed negotiations in an effort to resolve the dispute on an informal basis as promptly as practicable. In the event that the designated representatives are unable to resolve the dispute within thirty (30) days, or such other period as the Parties may unanimously agree upon, by unanimous agreement among the Parties such dispute may be voluntarily submitted to the use of the Commission's Alternative Means of Dispute Resolution (18 C.F.R. § 385.604, as those regulations may be amended from time to time), the Commission's Arbitration process (18 C.F.R. § 385.605, as those regulations may be amended from time to time) (collectively, "Commission ADR"), or such other dispute resolution process that the Parties may unanimously agree to utilize.

5.2 **Use of Dispute Resolution Processes:** In the event that the Parties voluntarily and unanimously agree to the use of a Commission ADR process or other dispute resolution procedure, then the Transmission Provider will have a notice posted to this effect on the Regional Planning Website, and an e-mail notice in that regard will be sent to Registered Stakeholders. In addition to the Parties, all Stakeholders and Sponsors shall be eligible to participate in any Commission ADR process as "participants", as that or its successor term in meaning is used in 18 C.F.R. §§ 385.604, 385.605 as may be amended from time to time, for purposes of the Commission ADR process; provided, however, any such Stakeholder or Sponsor must first have provided written notice to the Transmission Provider within thirty (30) calendar days of the posting on the Regional Planning Website of the Parties' notice of their intent to utilize a Commission ADR Process.

5.3 **Costs:** Each Party involved in a dispute resolution process hereunder, and each "participant" in a Commission ADR Process utilized in accordance with Section 5.2, shall be responsible for its own costs incurred during the dispute resolution process. Should additional costs be incurred during the dispute resolution process that are not directly attributable to a single Party/participant, then the Parties/participants shall each bear an equal share of such cost.

5.4 **Rights under the Federal Power Act:** Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

6. Regional Participation[8]

6.1 General: The Transmission Provider coordinates with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources.

6.2 Coordination within the SERTP: The Transmission Provider coordinates through this Southeastern Regional Transmission Planning Process with the other transmission providers and owners within this region and the corresponding meetings, communications, and data and information exchanges. The particular activities that are coordinated are the annual preparation of this region's ten (10) year transmission expansion plans and the preparation of the Economic Planning Studies addressed in Section 7 below. The transmission, generation, and demand resource transmission expansion plan/enhancement alternatives suggested by the Stakeholders pursuant to Section 3.5.3(3) will be considered in regional studies conducted to improve the reliability of the bulk power system and this information will be shared with the other transmission owners in this region.

6.3 Coordination with the Other Participating Transmission Owners in the Southeast Inter-Regional Participation Process: On an inter-regional basis, the Transmission Provider coordinates with the transmission systems with which the Transmission Provider is interconnected, with the exception of the utilities in the Florida Reliability Coordination Council ("FRCC"), through the Southeast Inter-

[8]In accordance with Order No. 1000, this planning principle only applies to the Transmission Provider's local transmission planning process.

Regional Participation Process ("SIRPP") attached hereto as Exhibit K-2 and incorporated herein by reference, and the corresponding meetings, communications, and data and informational exchanges. In that regard, a link to the SIRPP website is found on the Transmission Provider's OASIS. The transmission owners participating in the SIRPP are identified on the SIRPP website ("SIRPP Sponsors"). The particular activities that the SIRPP sponsors coordinate are the preparation of the inter-regional Economic Planning Studies addressed in Section 7 below and in Exhibit K-2, and the review with stakeholders of the data, assumptions, and assessment activities that are then being conducted on a SERC-wide basis.

6.4 Coordination with Other SERC Members: The Transmission Provider is a member of the SERC Reliability Corporation ("SERC") and coordinates with other SERC members in reliability transmission planning. At least as of December 17, 2008, the SERC members are identified on SERC's website. SERC is the regional entity responsible for promoting the reliability and adequacy of the bulk power system in the area served by its member systems. SERC has in place various committees and subcommittees, whose members are employees of SERC members, to perform those functions, including the promotion of the reliability and adequacy of the bulk power system as related to the planning and engineering of the electric systems. At least as of December 17, 2008, the SERC committees are identified on SERC's website. Through these committee processes, the particular transmission planning activities that are coordinated with the SERC members are the creation of a SERC regional model and the preparation of a simultaneous feasibility assessment, which are discussed in further detail below.

6.5 Coordination with the Transmission Owners in the FRCC

6.5.1 Reliability Coordination with the Transmission Owners in the FRCC: As discussed in Exhibit K-2, seams coordination for the SIRPP occurs at the regional level where external planning processes adjoin the SIRPP. In that regard, the Transmission Provider coordinates with the transmission providers in the FRCC through a reliability coordination arrangement for the purpose of safeguarding and augmenting the reliability of the Transmission Provider's Transmission System and that of the FRCC. This arrangement provides for exchanges of information and system data between the Transmission Provider and the FRCC transmission providers for the coordination of planning and operations in the interest of reliability. This arrangement also provides the mechanism for regional studies and recommendations designed to improve the reliability of the interconnected bulk power system. Duties under the arrangement are as follows: (1) coordination of generation and transmission system planning, construction, operating, and protection to maintain maximum reliability; (2) coordination of interconnection lines and facilities for full implementation of mutual assistance in emergencies; (3) initiation of joint studies and investigations pertaining to the reliability of bulk power supply facilities; (4) coordination of maintenance schedules of generating units and transmission lines; (5) determination of requirements for necessary communication between the parties; (6) coordination of load relief measures and restoration procedures; (7) coordination of spinning reserve requirements; (8) coordination of voltage levels and reactive power supply; (9) other matters relating to the reliability of bulk power supply required to meet customer service requirements; and (10) exchange of necessary information, such as magnitude and characteristics of actual and forecasted loads, capability of generating facilities, programs of capacity additions, capability of bulk power interchange facilities, plant and system emergencies, unit outages, and line outages.

6.5.2 Economic Planning Studies with the FRCC: The Transmission Provider and the FRCC have developed procedures for the performance of Economic Planning Studies that are selected by their Stakeholders through their respective Attachment K transmission planning processes for bulk power transfers that involve both the FRCC and the Transmission Provider. Those procedures are posted on the Regional Planning Website (including the FRCC/SERTP process for requesting inter-regional economic studies and a description of how information, modeling data and expansion plans are shared).

6.6 Reliability Planning Process

6.6.1 General: The Transmission Provider's reliability planning process with the transmission providers and owners participating in the SERTP and SIRPP is described in documentation posted on the Regional Website and the Inter-Regional Website.

6.6.2 A Description of How the Various Reliability Study Processes Interact with Each Other: The reliability planning process in the Southeast is a "bottom-up" process. Specifically, the Transmission Provider's 10-year transmission expansion plan is the base case that it uses for reliability planning processes, with it being the Transmission Provider's input into the development of the SERC regional model. In addition, the results of the FRCC coordination activities and of any *ad hoc* coordination activities are incorporated into the Transmission Provider's transmission expansion plan. These processes are discussed further below on both (a) a local and regional level (*e.g.* Southeastern Regional Transmission Planning level) and (b) an inter-regional (*e.g.* SERC-wide level).

(a)(i) **Bottom-up Reliability Planning:** The bulk of the substantive transmission planning in the Southeast occurs as transmission owners, such as the Transmission Provider, develop their reliability transmission expansion plans. In this regard, the Transmission Provider's reliability plan is generally developed by determining the required 10-year transmission expansion plan to satisfy load, resources, and transmission service commitments throughout the 10-year reliability planning horizon. The development of the Transmission Provider's reliability plan is facilitated through the creation of transmission models (base cases) that incorporate the current ten (10) year transmission expansion plan, load projections, resource assumptions (generation, demand response, and imports), and transmission service commitments within the region. The transmission models also incorporate external regional models (at a minimum the current SERC models) that are developed using similar information.

(a)(ii) **Bottom-Up Reliability Study Process:** The transmission models created for use in developing the transmission provider's reliability 10-year transmission expansion plan are analyzed to determine if any planning criteria concerns (including, at a minimum, North American Electric Reliability Corporation ("NERC") planning criteria) are projected. In the event one or more planning criteria concerns are identified, the transmission owners will develop solutions for these projected limitations. As a part of this study process, the transmission owners will reexamine the current regional reliability 10-year transmission expansion plans (determined through the previous year's regional reliability planning process) to determine if the current plan can be enhanced based on the updated assumptions and any new planning criteria concerns identified in the analysis. The enhancement process may include the deletion and/or modification to any of the existing reliability transmission enhancements identified in the previous year's reliability planning process.

(a)(iii) **Identification of Reliability Transmission Enhancements**: Once a planning criteria concern is identified or the enhancement process identifies the potential for a superior solution, the transmission owner will then determine if any neighboring planning process is potentially impacted by the projected limitation. Potentially impacted transmission owners are then contacted to determine if there is a need for an *ad hoc* coordinated study. In the event one or more neighboring transmission owners agree that they would be impacted by the projected limitation or identifies the potential for a superior reliability solution based on transmission enhancements in their current reliability plan, an *ad hoc* coordinated study is initiated. Once the study has been completed, the identified reliability transmission enhancements will then be incorporated into the ten (10) year transmission expansion plan (*i.e.*, the plan due to be implemented the following year) as a reliability project.

(b)(i) **SERC-Wide Assessments and Planning Activities**: After their transmission models are developed, the transmission owners within SERC create a SERC-wide transmission model and conduct a long-term reliability assessment. The intent of the SERC-wide reliability assessment is to determine if the different reliability transmission expansion plans are simultaneously feasible and to otherwise ensure that the transmission owners are using consistent models and data. Additionally, the reliability assessment measures and reports transfer capabilities between regions and transmission owners within SERC. The SERC-wide assessment serves as a valuable tool for each of the transmission owners to reassess the need for additional reliability joint studies.

(b)(ii) **SERC Transmission Model Development:** The construction of the SERC transmission model is a "bottom-up" process. In particular, SERC transmission models are developed by the transmission owners in SERC through an annual model development process. Each transmission owner in SERC, incorporating input from their regional planning process, develops and submits their 10-year transmission models to a model development databank, with the models and the databank then being used to create a SERC-wide model for use in the reliability assessment. Additionally, the SERC-wide models are then used in the SERTP planning process as an update (if needed) to the current transmission models and as a foundation (along with the Multiregional Modeling Working Group ("MMWG") models) for the development of the transmission provider's transmission models for the following year.

(b)(iii) **Additional Reliability Joint Studies:** As mentioned above, the SERC-wide reliability assessment serves as a valuable tool for the transmission owners to reassess the need for additional reliability joint studies. If the SERC-wide reliability model projects additional planning criteria concerns that were not identified in the transmission owners' reliability studies, then the impacted transmission owners will initiate one or more *ad hoc* inter-regional coordinated study(ies) (in accordance with existing Reliability Coordination Agreements) to better identify the planning criteria concerns and determine inter-regional reliability transmission enhancements to resolve the limitations. Once the study(ies) is completed, required reliability transmission enhancements will be incorporated into the Transmission Provider's ten (10) year expansion plan as a reliability project. Accordingly, planning criteria concerns identified at the SERC-wide level are "pushed down" to the transmission owner level for detailed resolution.

6.6.3 A Description of How Stakeholders May Participate in These Processes

(a)(i) **Participation Through the Southeastern Regional Transmission Planning Process:** Since the bulk of the reliability transmission planning occurs as a "bottom up" process in the development of the Transmission Provider's ten (10) year transmission expansion plan, Stakeholders may participate in these reliability planning processes by participating in the Southeastern Regional Transmission Planning Process. Specifically, the ten (10) year transmission expansion plan is the Transmission Provider's input into the SERC model development, and the results of the FRCC coordination and of any *ad hoc* coordination studies are incorporated into the ten (10) year transmission expansion plan. As discussed in Section 1.2.2, at the Preliminary Expansion Plan Meeting, Stakeholders are provided the opportunity to review and comment (and allowed to propose alternatives concerning enhancements found in): the Transmission Provider's preliminary transmission expansion plan, which is the Transmission Provider's input into (1) SERC's regional model development, (2) coordination with the FRCC, and (3) any *ad hoc* coordination activities. As discussed in Section 1.2.3, at the Second RPSG Meeting, the Stakeholders are provided feedback regarding the expansion plan alternatives that they submitted at the First RPSG Meeting and are provided an overview of the results of the SERC regional model development for that year, as well as the results of any on-going coordination activities with the FRCC transmission providers and any *ad hoc* coordination activities. As discussed in Section 1.2.4, at the Annual Transmission Planning Summit and Assumptions Input Section, the Stakeholders are provided an overview of the ten (10) year transmission expansion plan, the results of that year's coordination study activities with the FRCC transmission providers, and the results of any *ad hoc* coordination activities. In addition, Stakeholders are provided an open forum regarding: the data gathering and transmission model assumptions that will be used for purposes of the ten (10) year transmission expansion plan to be developed the following year (which will constitute the Transmission Provider's input into the SERC regional model development for the following year); FRCC model development; and any *ad hoc* coordination studies.

(a)(ii) **Participation Through the SIRPP:** As shown on the Southeast Inter-Regional Participation Process Diagram contained in Exhibit K-2, the particular activities that the SIRPP sponsors coordinate are the preparation of the inter-regional Economic Planning Studies addressed in Section 7 below and in Exhibit K-2. In addition, the SIRPP sponsors will review with stakeholders the data, assumptions, and assessment that are then being conducted on a SERC-wide basis at: the 1^{st} Inter-Regional Stakeholder Meeting; the 2^{nd} Inter-Regional Stakeholder Meeting; and the 3^{rd} Inter-Regional Stakeholder Meeting.

(a)(iii) **Membership in SERC**: Interested Stakeholders may further participate in SERC processes by seeking to become a member of SERC. At least as of December 17, 2008, the requirements to become a SERC member are specified on SERC's website.

6.7 Timeline and Milestones: The general timelines and milestones for the performance of the reliability planning activities are provided in Exhibit K-3, which also provides a flowchart diagramming the steps of the Southeastern Regional Transmission Planning Process.

7. Economic Planning Studies

7.1 General – Economic Planning Study Requests: Stakeholders will be allowed to request that the Transmission Provider perform up to five (5) Stakeholder requested economic planning studies ("Economic Planning Studies") on an annual basis. Requests that are inter-regional in nature will be addressed in the SIRPP. Accordingly, it is expected that the RPSG will coordinate with other inter-regional stakeholders regarding Economic Planning Studies that are inter-regional in nature.

7.2 Parameters for the Economic Planning Studies: These Economic Planning Studies shall be confined to sensitivity requests for bulk power transfers and/or to evaluate potential upgrades or other investments on the Transmission System that could reduce congestion or integrate new resources. Bulk power transfers from one area to another area with the region encompassed by this Southeastern Regional Transmission Planning Process (the "Region") shall also constitute valid requests. The operative theory for the Economic Planning Studies is for them to identify meaningful information regarding the requirements for moving large amounts of power beyond that currently feasible, whether such transfers are internal to the Region or from this Region to interconnected regions. It should again be noted that requests that are inter-regional in nature will be addressed in the SIRPP.

7.3 **Other Tariff Studies:** The Economic Planning Studies are not intended to replace System Impact Studies, Facility Studies, or any of the studies that are performed for transmission delivery service or interconnection service under the Tariff.

7.4 **Clustering:** The RPSG should consider clustering similar Economic Planning Study requests. In this regard, if two or more of the RPSG requests are similar in nature and the Transmission Provider concludes that clustering of such requests and studies is appropriate, the Transmission Provider may, following communications with the RPSG, cluster those studies for purposes of the transmission evaluation. It is foreseeable that clustering of requests may occur during the SIRPP.

7.5 **Additional Economic Planning Studies:** Should a Stakeholder(s) request the performance of an Economic Planning Study in addition to the above-described five (5) Economic Planning Studies that the RPSG may request during a calendar year, then any such additional Economic Planning Study will only be performed if such Stakeholder(s) first agrees to bear the Transmission Provider's actual costs for doing so and the costs incurred by any other Sponsor to perform such Economic Planning Study, recognizing that the Transmission Provider may only conduct a reasonable number of transmission planning studies per year. If affected by the request for such an additional Economic Planning Study, the Transmission Provider will provide to the requesting Stakeholder(s) a non-binding but good faith estimate of what the Transmission Provider expects its costs to be to perform the study prior to the Stakeholder(s) having to agree to bear those costs. Should the Stakeholder(s) decide to proceed with the additional study, then it shall pay the Transmission Provider's and other affected Sponsor[s]' estimated study costs up-front, with those costs being trued-up to the Transmission Provider's and other affected Sponsor[s]' actual costs upon the completion of the additional Economic Planning Study.

7.6 Economic Planning Study Process

1. Stakeholders will be prompted at the Annual Transmission Planning Summit to provide requests for the performance of Economic Planning Studies. Corresponding announcements will also be posted on the Regional Planning Website, and Registered Stakeholders will also receive e-mail notifications to provide such requests. An Economic Planning Study Request Form will be made available on the Regional Planning Website, and interested Stakeholders may submit any such completed request form on the non-secure area of the Regional Planning Website (unless such study request contains CEII, in which case the study request shall be provided to the Transmission Provider with the CEII identified, and the study request shall then be posted on the secure area of the Regional Planning Website).

2. Prior to each First RPSG Meeting, the RPSG shall compile the Economic Planning Study requests. At the First RPSG Meeting, the RPSG shall meet to discuss and select up to five (5) Economic Planning Studies to be requested to be performed. At the First RPSG Meeting, the Transmission Provider will coordinate with the RPSG and any interested Stakeholders to

facilitate the RPSG's efforts regarding its development and selection of the Economic Planning Study requests. Once the RPSG selects the Economic Planning Study(ies) (up to five annually), the RPSG will notify the Transmission Provider, who will post the results on the Regional Planning Website.

3. The Transmission Provider will post on the secure area of the Regional Planning Website the study assumptions for the five (5) Economic Planning Studies within thirty (30) days of the postings of the selected Economic Planning Studies on the Regional Planning Website. Registered Stakeholders will receive an e-mail notification of this posting, and an announcement will also be posted on the Regional Planning Website.

4. Stakeholders will have thirty (30) calendar days from the Transmission Provider's posting of the assumptions for the RPSG to provide comments regarding those assumptions. Any such comments shall be posted on the secure area of the Regional Planning Website if the comments concern CEII.

5. The preliminary results of the Economic Planning Studies will be presented at the Second RPSG Meeting. These results and related data will be posted on the secure area of the Regional Planning Website a minimum of 10 calendar days prior to the Second RPSG Meeting. Study results that are inter-regional in nature will be reported to the RPSG and interested Stakeholders and posted as they become available from the SIRPP. The Second RPSG Meeting will be an interactive session with the RPSG and

other interested Stakeholders in which the Transmission Provider will explain the results, alternatives, methodology, criteria, and related considerations pertaining to those preliminary results. At that meeting, the Stakeholders may submit alternatives to the enhancement solutions identified in those preliminary results. All such alternatives must be submitted by Stakeholders within thirty (30) calendar days from the close of the Second RPSG Meeting. The Transmission Provider will consider the alternatives provided by the Stakeholders.

6. The final results of the Economic Planning Studies will be presented at the Annual Transmission Planning Summit, and the Transmission Provider will report regarding its consideration of the alternatives provided by Stakeholders. These final results will be posted on the secure area of the Regional Planning Website a minimum of 10 calendar days prior to the Transmission Planning Summit. Study results that are inter-regional in nature will be reported to the RPSG and interested Stakeholders and posted as they become available from the SIRPP.

7. The final results of the Economic Planning Studies will be non-binding upon the Transmission Provider and will provide general non-binding estimations of the required transmission upgrades, timing for their construction, and costs for completion.

8. Order No. 890 Cost Allocation Principle[9]

8.1 General: The following provides the Transmission Provider's methodologies for allocating the costs of new transmission facilities that do not fit under the general Tariff rate structure under two scenarios. The first methodology addresses the allocation of the costs of economic transmission upgrades that are identified in the Economic Planning Studies and that are not otherwise associated with transmission service provided under the Tariff and are not associated with the provision of transmission service under other arrangements, such as the Transmission Provider's provision of bundled service to its Native Load Customers. The second methodology addresses upgrades that are not required to satisfy the Transmission Provider's planning standards and/or ERO or RE reliability standards, and thus would not otherwise be included in the transmission expansion plan, but that a Stakeholder, including a Transmission Customer, may want to have installed to provide additional reliability benefits above those necessary to satisfy the Transmission Provider's planning criteria and/or ERO or RE reliability standards ("Enhanced Reliability Upgrades").

8.2 Cost Allocation Methodology for Economic Upgrades

8.2.1 Identification of Economic Upgrades: The transmission expansion plan will identify the transmission upgrades that are necessary to ensure the reliability of the Transmission System and to otherwise meet the needs of long-term firm transmission service commitments ("Reliability

[9] In accordance with Order No. 1000, this planning principle only applies to the Transmission Provider's local transmission planning process.

Upgrades") in accordance with the Transmission Provider's planning standards and/or ERO or RE reliability standards. All of the upgrades identified in the Economic Planning Studies that are not identified in the transmission expansion plan, and are thus not such Reliability Upgrades, shall constitute "Economic Upgrades".

8.2.2 Request for Performance of Economic Upgrades: Within thirty (30) calendar days of the posting of the final results of the underlying Economic Planning Study[ies], one or more entities ("Initial Requestor[s]") that would like the Transmission Provider to construct one or more Economic Upgrades identified in the Economic Planning Study[ies] may submit a request for the Transmission Provider to construct such Economic Upgrade[s]. The Initial Requestor[s] should identify the percentage of cost responsibility for the Economic Upgrade[s] that the Initial Requestor[s] is requesting cost responsibility. The request must consist of a completed request application, the form of which will be posted on the Regional Planning Website ("Economic Upgrade Application"). The Transmission Provider will post the request on the secure area of the Regional Planning Website. Other entities ("Subsequent Requestor[s]") that also would like the Transmission Provider to construct the Economic Upgrade[s] sought by the Initial Requestor[s] shall notify the Transmission Provider of its intent, along with the percentage of cost responsibility that the Subsequent Requestor[s] is requesting cost responsibility, by following the instructions specified on the Regional Planning Website within thirty (30) calendar days of the Initial Requestor[s]' posting of its Economic Upgrade Application on the Regional Planning Website (collectively, the Initial Requestor[s] and the Subsequent Requestor[s] shall be referred to as the "Requestor[s]").

8.2.3 Allocation of the Costs of the Economic Upgrades: The costs of the Economic Upgrades shall be allocated to each Requestor based upon the percentage of cost responsibility that it has requested in its respective request. Should the total amount of percentage requests for cost responsibility for the Economic Upgrade[s] by the Requestors not equal one-hundred percent (100%), regardless if the requested amount is less than or exceeds one-hundred percent (100%), then the Requestor[s]' cost responsibility will be adjusted on a pro rata basis based upon the total percentage identified by all of the Requestor[s] relative to one-hundred percent (100%) so that all of the cost responsibility for the Economic Upgrade[s] is allocated to the Requestor[s]. If one or more of the Requestors do not identify the percentage of cost responsibility for which it is requesting cost responsibility, then the Requestors shall bear the costs of the Economic Upgrade[s] in equal shares based upon the number of Requestors. The Requestor[s] shall bear cost responsibility for the actual costs of the Economic Upgrades. Should a Requestor later not enter into an agreement with the Transmission Provider for the construction of the Economic Upgrade[s], then the remaining Requestor[s]' cost responsibility will be recalculated on a pro rata basis based upon the percentage of cost responsibility requested or based upon the remaining number of Requestor[s] if that methodology was used to allocate the Economic Upgrade[s]' costs.

8.2.4 Cost Allocation for the Acceleration, Expansion, Deferral, or Cancellation of Reliability Upgrades: Should the Transmission Provider conclude that the construction of an Economic Upgrade[s] would accelerate the construction of, or require the construction of a more expansive, Reliability Upgrade, then the Requestor[s] shall bear the costs of such acceleration or expansion. Should the Transmission Provider conclude that the construction of the Economic Upgrade[s] would result in the deferral or cancellation of a Reliability Upgrade, then the costs of the Economic Upgrade[s] allocated to the Requestor[s] shall be reduced by the present value of the amount of savings caused by the deferral or cancellation.

8.2.5 Implementing Agreements and Regulatory Approvals: The Transmission Provider will not be obligated to commence design or construction of any Economic Upgrade until (i) a binding agreement[s] with all of the Requestor[s] for such construction by the Transmission Provider and payment by the Requestor[s] of its allocated cost responsibility (in accordance with Section 8.2.3 above) is executed by the Transmission Provider, all other affected Sponsor[s], and all of the Requestor[s]; (ii) all of the Requestor[s] provide (and maintain, subject to reduction as set forth in (iii) below) the Transmission Provider security, in a form acceptable to the Transmission Provider, for the full costs of the design and construction; and (iii) appropriate commitments to construct are in place for all affected third party transmission providers (*e.g.*, other Sponsors). In addition, the Transmission Provider shall not be obligated to commence any phase of design or construction of any Economic Upgrade unless the Requestor[s] has first paid to the Transmission Provider in immediately available funds via wire transfer the Transmission Provider's estimated costs for that phase of design or construction (it being understood that security provided under (ii) above may be reduced on a dollar-for-dollar basis with respect to such payments received by Transmission Provider as and when they are final and are no longer subject to being voided or set aside), with the Requestor[s] bearing the actual costs of design and construction upon completion of the Economic Upgrade[s] pursuant to a true-up to the estimated costs already paid. Furthermore, the Transmission Provider shall not be obligated to commence construction, or to continue construction, if all necessary regulatory approvals are not obtained or maintained, with the Transmission Provider having to make a good faith effort to obtain all such approvals. The costs associated with obtaining and maintaining such regulatory approvals shall be included in the total costs of the Economic Upgrades and shall otherwise be borne by the Requestors.

8.3 Cost Allocation Methodology for Enhanced Reliability Upgrades

8.3.1 Enhanced Reliability Upgrades: The transmission expansion plan will identify the Reliability Upgrades, which are the transmission upgrades that are necessary to ensure the reliability of the Transmission System and to otherwise meet the needs of long-term firm transmission service commitments in accordance with the Transmission Provider's planning standards and/or ERO or RE reliability standards. Should one or more Stakeholders, including a Transmission Customer, determine that it wants an upgrade installed to provide additional reliability benefits above those necessary to satisfy the Transmission Provider's planning criteria and/or ERO or RE reliability standards (*i.e.*, an Enhanced Reliability Upgrade), then the costs of any such Enhanced Reliability Upgrade shall be directly assigned to that Stakeholder[s] ("Requesting Stakeholder[s]") without the provision of transmission credits or other means of reimbursement from the Transmission Provider for such direct assignment costs.

8.3.2 Cost Allocation of the Direct Assignment Costs Should Multiple Stakeholders Desire the Same Enhanced Reliability Upgrade: Should multiple Stakeholders want the installation and construction of the same Enhanced Reliability Upgrade[s], then the direct assignment costs for such Enhanced Reliability Upgrade[s] shall be allocated to those Requesting Stakeholders in equal shares, unless those Requesting Stakeholders agree in writing to a different cost allocation approach prior to the Transmission Provider assigning those costs.

8.3.3 Implementing Agreements and Regulatory Approvals: The Transmission Provider will not be obligated to commence design or construction of any Enhanced Reliability Upgrade until (i) a binding agreement[s] with the Requesting Stakeholder[s] for such construction by the Transmission Provider and payment by the Requesting Stakeholder[s] of its direct assignment costs (in accordance with Sections 8.3.1 and 8.3.2 above) is executed by the Transmission Provider and all of the Requesting Stakeholders seeking the construction of such Enhanced Reliability Upgrade[s] and (ii) all of the Requesting Stakeholder[s] provide (and maintain, subject to reduction as set forth in the following sentence) the Transmission Provider security, in a form acceptable to the Transmission Provider, for the full costs of the design and construction. In addition, the Transmission Provider shall not be obligated to commence any phase of design or construction of any Enhanced Reliability Upgrade unless the Requesting Stakeholder[s] has first paid to the Transmission Provider in immediately available funds via wire transfer the Transmission Provider's estimated costs for that phase of design or construction (it being understood that security provided under (ii) above may be reduced on a dollar-for-dollar basis with respect to such payments received by Transmission Provider as and when they are final and are no longer subject to being voided or set aside), with the Requesting Stakeholder[s] bearing the actual costs of design and construction upon completion of the Enhanced Reliability Upgrade[s] pursuant to a true-up to the estimated costs already paid. Furthermore, the Transmission Provider shall not be obligated to commence construction, or to continue construction, if all necessary regulatory approvals are not obtained or maintained, with the Transmission Provider having to make a good faith effort to obtain all such approvals. The costs associated with obtaining and maintaining such regulatory approvals shall be included in the total costs of the Enhanced Reliability Upgrade[s] and shall otherwise be borne by the Requesting Stakeholder[s].

9. Recovery of Planning Costs: With the exception of the costs to perform more than five Economic Planning Studies (which will be directly assigned to the requestor), the Transmission Provider will recover the costs that it incurs in implementing its requirements under this Southeastern Regional Transmission Planning Process by adding those costs to the Annual Charge costs that it recovers under Informational Schedule D in the Tariff.

TRANSMISSION PLANNING AND COST ALLOCATION REQUIREMENTS OF ORDER NO. 1000

10. Consideration of Transmission Needs Driven by Public Policy Requirements

10.1 Procedures for the Consideration of Transmission Needs Driven by Public Policy Requirements: The Transmission Provider addresses transmission needs driven by enacted state and federal laws and/or regulations ("Public Policy Requirements") in its routine planning, design, construction, operation, and maintenance of the Transmission System. In this regard, the Transmission

Provider addresses transmission needs driven by the Public Policy Requirements of load serving entities and wholesale transmission customers through the planning for and provision of long-term firm transmission services to meet i) native load obligations and ii) wholesale Transmission Customer obligations under the Tariff.

10.2 The Consideration of Transmission Needs Driven by Public Policy Requirements Identified Through Stakeholder Input and Proposals

10.2.1 Requisite Information: In order for the Transmission Provider to consider transmission needs driven by Public Policy Requirements that are proposed by a Stakeholder, the Stakeholder must provide the following information via a submittal to the Regional Planning Website:

1. The applicable Public Policy Requirement, which must be a requirement established by an enacted state or federal law(s) and/or regulation(s); and

2. An explanation of the possible transmission need driven by the Public Policy Requirement identified in the immediately above subsection (1) (*e.g.*, the situation or system condition for which possible solutions may be needed, as opposed to a specific transmission project) and an explanation and/or demonstration that the current iteration of the transmission expansion plan(s) does not adequately address that need.

10.2.2 Deadline for Providing Such Information: Stakeholders that propose a transmission need driven by a Public Policy Requirement for evaluation by the Transmission Provider in the current transmission planning cycle must provide the requisite information identified in Section 10.2.1 to the Transmission Provider no later than 60 calendar days after the SERTP

Annual Transmission Planning Summit and Input Assumptions Meeting for the previous transmission planning cycle. That information is to be provided in accordance with the contact information provided on the Regional Planning Website.

10.3 Transmission Provider Evaluation of SERTP Stakeholder Input Regarding Potential Transmission Needs Driven by Public Policy Requirements

10.3.1 In the transmission planning process for that planning cycle, the Transmission Provider will evaluate Stakeholder input to determine if there is a transmission need driven by the Public Policy Requirement identified by the Stakeholder in Section 10.2 that should be addressed in the transmission expansion plan.

10.3.2 If a transmission need is identified that is not already addressed in the transmission expansion planning process, the Transmission Provider will identify a transmission solution to address the aforementioned need in the planning processes.

10.3.3 Stakeholder input regarding potential transmission needs driven by Public Policy Requirements may be directed to the governing Tariff process as appropriate. For example, if the potential transmission need identified by the Stakeholder is essentially a request by a network customer to integrate a new network resource, the request would be directed to that existing Tariff process.

10.4 Posting Requirement: The Transmission Provider will provide and post on the Regional Planning Website a response to Stakeholder input regarding transmission needs driven by Public Policy Requirements.

11. Merchant Transmission Developers Proposing Transmission Facilities Impacting the SERTP: Merchant transmission developers not seeking regional cost allocation pursuant to Sections 15-21 ("Merchant Transmission Developers") who propose to develop a transmission project(s) potentially impacting the Transmission System and/or transmission system(s) within the SERTP region shall provide information and data necessary for the Transmission Provider to assess the potential reliability and operational impacts of those proposed transmission facilities. That information should include:

- Transmission project timing, scope, network terminations, load flow data, stability data, HVDC data (as applicable), and other technical data necessary to assess potential impacts.

12. Enrollment

12.1 General Eligibility for Enrollment: A public utility or non-public utility transmission service provider and/or transmission owner having a statutory or tariff obligation to ensure that adequate transmission facilities exist within a portion of the SERTP region may enroll in the SERTP. Such transmission providers and transmission owners are thus potential beneficiaries for cost allocation purposes on behalf of their transmission customers. Entities that do not enroll will nevertheless be permitted to participate as stakeholders in the SERTP.

12.2 Enrollment Requirement In Order to Seek Regional Cost Allocation: While enrollment is not generally required in order for a transmission developer to be eligible to propose a transmission project for evaluation and potential selection in a regional plan for regional cost allocation purposes ("RCAP") pursuant to Sections 15-21, a potential transmission developer must enroll in the SERTP in order to be eligible to propose a transmission project for potential selection in a regional plan for RCAP if it, an affiliate, subsidiary, member, owner or parent company has load in the SERTP.

12.3 Means to Enroll: A public utility or non-public utility transmission service provider or transmission owners may provide an application to enroll in accordance with Sections 12.1 and 12.2 above, by executing the form of enrollment posted on the Regional Planning Website. The Transmission Provider is deemed to have enrolled for purposes of Order No. 1000 through this Attachment K.

12.4 List of Enrollees in the SERTP: The Transmission Provider will post and keep current on the Regional Planning Website a list of the public utility and non-public utility transmission service providers and transmission owners who have enrolled in the SERTP ("Enrollees").

12.5 Enrollment, Cost Allocation Responsibility, and Conditions Subsequent: Enrollment will subject Enrollees to cost allocation if, during the period in which they are enrolled, it is determined in accordance with this Attachment K that the Enrollee is a beneficiary of a new transmission project(s) selected in the regional transmission plan for RCAP; provided that, once enrolled, should the Commission, a Court, or any other governmental entity having the requisite authority modify, alter, or impose amendments to this Attachment K, then an enrolled non-public utility may immediately withdraw from this Attachment K by providing written notice within 60 days of that order or action, with the non-public utility's termination being effective as of the close of business the prior business day before said modification, alteration, or amendment occurred. The withdrawing Enrollee will be subject to regional and interregional cost allocations, if any, to which it had agreed and that were determined in accordance with this Attachment K during the period in which it was enrolled and was determined to be a beneficiary of new transmission facilities selected in the regional transmission plan for RCAP. Any withdrawing Enrollee will not be allocated costs for projects selected in a regional transmission plan for RCAP after its termination of enrollment becomes effective in accordance with the provisions of this Section 12.5.

12.6 Notification of Withdrawal: An Enrollee wanting to terminate its enrollment in the SERTP may do so by providing written notification of such intent to the Transmission Provider. Except for non-public utilities terminating pursuant to Section 12.5 above, the termination will be effective at the end of the then-current transmission planning cycle provided that the notification of withdrawal is provided to the Transmission Provider at least sixty (60) days prior to the Annual Transmission Planning Summit and Assumptions Input Meeting for that transmission planning cycle. The withdrawing Enrollee will be subject to regional and interregional cost allocations, if any, to which it had agreed and that were determined in accordance with this Attachment K during the period in which it was enrolled and was determined to be a beneficiary of new transmission facilities selected in the regional transmission plan for purposes of cost allocation.

Any withdrawing Enrollee will not be allocated costs for projects selected in a regional transmission plan for RCAP after its termination of enrollment becomes effective in accordance with the provisions of this Section 12.6.

13. Qualification Criteria to Submit a Regional Transmission Project Proposal for Potential Selection in a Regional Transmission Plan for Purposes of Cost Allocation

13.1 Transmission Developer Qualification Criteria: While additional financial and technical criteria may be required to be satisfied in order for a proposed transmission project to be selected and/or included in a regional plan for RCAP, a transmission developer must satisfy the following, initial qualification criteria to be eligible to propose a transmission project for potential selection in a regional transmission plan for RCAP.[10]

13.1.1 If the transmission developer or its parent or owner or any affiliate, member or subsidiary has load in the SERTP region, the transmission developer must have enrolled in the SERTP in accordance with Section 12.2.

13.1.2 In order to be eligible to propose a transmission project for consideration for selection in a regional plan for RCAP, the transmission developer must demonstrate that it satisfies the following, minimum financial capability and technical expertise requirements:

1. The transmission developer has and maintains a credit rating of BBB- or higher from Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P"), or a credit rating of Baa3 or higher from

[10] The regional cost allocation process provided hereunder in accordance with Sections 13-21 does not undermine the ability of the Transmission Provider and other entities to negotiate alternative cost sharing arrangements voluntarily and separately from this regional cost allocation method.

Moody's Investors Service, Inc. In addition, the transmission developer's parent company's credit rating may be used to satisfy this requirement but only if the parent company commits in writing to provide a guaranty for the transmission developer if the proposed transmission project is selected in a regional plan for RCAP;[11]

2. The transmission developer provides documentation of its capability to finance U.S. energy projects equal to or greater than the cost of the proposed transmission project; and

3. The transmission developer has the capability to develop, construct, operate, and maintain U.S. electric transmission projects of similar or larger complexity, size, and scope as the proposed project. The transmission developer must demonstrate such capability by providing, at a minimum, the following information:

    a. A summary of the transmission developer's: transmission projects in-service, under construction, and/or abandoned or otherwise not completed including locations, operating voltages, mileages, development schedules, and approximate installed costs; whether delays in project completion were encountered; and how these facilities are owned, operated and maintained. This may include projects and experience provided by a parent company or affiliates or other experience relevant to the development of the proposed project; and

    b. If it or a parent, owner, affiliate, or member has been found in violation of any NERC and/or Regional Entity reliability standard and/or the violation of regulatory requirement(s) pertaining to the development, construction, ownership, operation, and/or maintenance of electric infrastructure facilities, an explanation of such violations.

14. Transmission Facilities Potentially Eligible for RCAP: In order for a transmission project proposed by a transmission developer to be considered for evaluation and potential selection in a regional plan for RCAP, the project must be regional in nature in that it must be a major transmission project effectuating significant bulk electric transfers across

[11] If a project is selected in a regional plan for RCAP, having a BBB- and/or a Baa3 rating alone will not be sufficient to satisfy the requisite project security/collateral requirements.

the SERTP region and addressing significant electrical needs. A regional transmission project eligible for potential selection in a regional plan for RCAP would be a transmission line that would:

a. operate at a voltage of 300 kV or greater and span 100 miles or more within the SERTP; and

b. portions of said transmission line must be located in two or more balancing authority areas located in the SERTP.

1. A transmission project that does not satisfy (a) and (b) above but that would effectuate similar, significant bulk electric transfers across the SERTP region and address similar, significant regional electrical needs will be considered on a case-by-case basis;

2. The proposed transmission project cannot be an upgrade to an existing facility. In addition, the proposed transmission project cannot be located on the property and/or right-of-way ("ROW") belonging to anyone other than the transmission developer absent the consent of the owner of the existing facility or ROW, as the case may be;

3. In order for the proposed transmission project to be a more efficient and cost effective alternative to the projects identified by the transmission providers through their planning processes, it should be materially different than projects already under consideration and materially different than projects that have been previously considered in the expansion planning process; and

4. The proposed transmission project must be able to be constructed and tied into the transmission system by the required in-service date.

15. Submission and Evaluation of Proposals for Potential Selection in a Regional Transmission Plan for RCAP

15.1 Information to be Submitted: A transmission developer must submit the following information in support of a transmission project it proposes for potential selection in a regional transmission plan for RCAP:

1. Documentation of the transmission developer's ability to satisfy the qualification criteria required in Section 13;

2. Sufficient information for the Transmission Provider to determine that the potential transmission project satisfies the regional eligibility requirements of Section 14;

3. If it or a parent, owner, affiliate, or member who will be performing work in connection with the potential transmission project is registered with NERC or other industry organizations pertaining to electric reliability and/or the development, construction, ownership, or operation, and/or maintenance of electric infrastructure facilities, a list of those registrations.

4. A description of the proposed transmission project that details the intended scope (including the various stages of the project development such as engineering, ROW acquisition, construction, recommended in-service date, etc.);

5. A capital cost estimate of the proposed transmission project. If the cost estimate differs greatly from generally accepted estimates of projects of comparable scope, the transmission developer will be required to support such differences;

6. Documentation of the technical analysis performed supporting the position that the proposed transmission project addresses the transmission needs and does so more efficiently and cost-effectively than specific projects included in the latest transmission expansion plan. Documentation must include the following:

   - The identification of: (a) transmission projects in the latest expansion plan that would be displaced by the proposed project, and (b) any additional projects that may be required in order to implement the proposed project; and

   - The data and/or files necessary to evaluate the transmission developer's analysis of the proposed transmission project;

7. The transmission developer must provide a reasonable explanation of, as it pertains to its proposed project, its planned approach to satisfy applicable regulatory requirements and its planned approach to obtain requisite authorizations necessary to acquire rights of way and to construct, operate, and maintain the proposed facility in the relevant jurisdictions;

   - The transmission developer should not expect to use the Transmission Provider's right of eminent domain for ROW acquisition; and

8. An administrative fee of $25,000 to off-set the costs to review, process and evaluate each transmission project proposal. A refund of $15,000 will be provided to the transmission developer if:

- The transmission developer or its proposal is determined to not satisfy the qualification criteria in Section 13 through 15.1; or
- The transmission developer withdraws its proposal by providing written notification of its intention to do so to the Transmission Provider prior to the First RPSG Meeting and Interactive Training Session for that transmission planning cycle.

15.2 Deadline for Submittal: In order for its transmission project to be considered for RCAP in the current transmission planning cycle, a transmission developer must provide the requisite information identified in Sections 13 through 15.1 to the Transmission Provider in accordance with the contact information provided on the Regional Planning Website no later than 60 calendar days after the SERTP Annual Transmission Planning Summit and Input Assumptions Meeting for the previous transmission planning cycle.

15.3 Initial Review of Qualification Criteria and Opportunity for Cure: The Transmission Provider will notify transmission developers who do not meet the qualification criteria in Section 13 through 15.1, or who provide an incomplete submittal, within 30 calendar days of the submittal deadline to allow the transmission developers an opportunity to remedy any identified deficiency(ies). Transmission developers, so notified, will have 15 calendar days to resubmit the necessary supporting documentation to remedy the identified deficiency.

15.4 Change in the Transmission Developer's Qualification Information or Circumstances: The transmission developer has an obligation to update and report in writing to the Transmission Provider any change to its information that was provided as the basis for its satisfying the requirements of Sections 13 through 15, except that the transmission developer is not expected to update its technical analysis performed for purposes of Section 15.1(6) to reflect updated transmission planning data as the transmission planning cycle(s) progresses. If at any time the Transmission Provider concludes that a transmission developer or a potential transmission project proposed for possible selection in a regional plan for RCAP no longer satisfies such requirements specified in Sections 13 through 15, then the Transmission Provider may remove the transmission developer's potential transmission project(s) from consideration for potential selection in a regional plan for RCAP and/or remove any and all such transmission project(s) from the selected category in a regional plan for RCAP, as applicable.

16. Evaluation of Proposals for Selection in a Regional Transmission Plan for RCAP

16.1 Potential Transmission Projects Seeking RCAP Will be Evaluated in the Normal Course of the Transmission Planning Process: During the course of the then-current transmission expansion planning cycle (and thereby in conjunction with other system enhancements under consideration in the transmission planning process), the Transmission Provider will evaluate current transmission needs and assess alternatives to address current needs including the potential transmission projects proposed for possible selection in a regional plan for RCAP by transmission developers. Such evaluation will be in accordance with, and subject to (among other things), state law pertaining to transmission ownership, siting, and construction. Utilizing coordinated models and assumptions, the Transmission Provider will apply its planning guidelines and criteria to evaluate submittals and determine whether:

1. The proposed transmission project addresses an underlying transmission need(s);

2. The proposed transmission project addresses transmission needs that are currently being addressed with projects in the transmission planning process and if so, which projects could be displaced by the proposed transmission project;[12]

3. Any additional projects would be required to implement the proposed transmission project.

16.2 Transmission Benefit-to-Cost Analysis Based Upon Planning Level Cost Estimates

16.2.1 Based upon the evaluation outlined in Section 16.1, the Transmission Provider will assess whether the proposed transmission project seeking selection in a regional plan for RCAP is considered at that point in time to yield meaningful, net regional benefits. Specifically, the proposed transmission project should yield a regional transmission benefit-to-cost ratio of at least 1.25 and no individual Impacted Utility should incur increased, unmitigated transmission costs.[13]

a. The benefit used in this calculation will be quantified by the transmission costs that the Beneficiaries would avoid due to their transmission projects being displaced by the transmission developer's proposed transmission project.

[12] Entities that are identified to potentially have one or more of their planned transmission projects displaced by the transmission developer's potential transmission project for possible selection in a regional plan for RCAP shall be referred to as "Beneficiaries."

[13] An entity would incur increased, unmitigated transmission costs should it incur more costs than displaced benefits and not be compensated/made whole for those additional costs. For purposes of this Attachment K, the terms "Impacted Utilities" shall mean: i) the Beneficiaries identified for the proposed transmission project and ii) any entity identified in this Section 16.2.1 to potentially have increased costs in order to implement the proposal.

b. The cost used in this calculation will be quantified by the transmission cost of the project proposed for selection in a regional transmission plan for RCAP plus the transmission costs of any additional projects required to implement the proposal.

c. The Transmission Provider will develop planning level cost estimates for use in determining the regional benefit-to-cost ratio. Detailed engineering estimates may be used if available.

16.2.2 For potential transmission projects found to satisfy the foregoing benefit-to-cost analysis, the Transmission Provider and the Impacted Utilities will then consult with the transmission developer of that project to establish a schedule reflecting the expected in-service date of the project for: 1) the transmission developer to provide detailed financial terms for its proposed project that are acceptable to each Beneficiary and 2) the proposed transmission project to receive approval for selection in a regional plan for RCAP from the jurisdictional and/or governance authorities of the Impacted Utilities.

16.3 The Transmission Developer to Provide More Detailed Financial Terms Acceptable to the Beneficiaries and the Performance of a Detailed Transmission Benefit-to-Cost Analysis: By the date specified in the schedule established in Section 16.2.2,[14] the transmission developer shall identify the detailed financial terms for its proposed project, establishing in detail: (a) the total cost to be allocated to the Beneficiaries if the proposal were to be selected in a

[14]The schedule established in accordance with Section 16.2.2 will reflect considerations such as the timing of those transmission needs the regional project may address as well as the lead-times of the regional project, transmission projects that must be implemented in support of the regional project, and projects that may be displaced by the regional project. This schedule may be revised by the Transmission Provider and the Impacted Utilities, in consultation with the transmission developer, as appropriate to address, for example, changes in circumstances and/or underlying assumptions.

regional plan for RCAP, and (b) the components that comprise that cost, such as the costs of:

a. Engineering, procurement, and construction consistent with Good Utility Practice and standards and specifications acceptable to the Transmission Provider,

b. Financing costs, required rates of return, and any and all incentive-based (including performance based) rate treatments,

c. Ongoing operations and maintenance of the proposed transmission project,

d. Provisions for restoration, spare equipment and materials, and emergency repairs, and

e. Any applicable local, state, or federal taxes.

To determine whether the proposed project is considered at that time to remain a more efficient and cost effective alternative, the Transmission Provider will then perform a more detailed 1.25 transmission benefit-to-cost analysis consistent with that performed pursuant to Section 16.2.1. This more detailed transmission analysis will be based upon the detailed financial terms provided by the transmission developer, as may be modified by agreement of the transmission developer and Beneficiary(ies), and any additional, updated, and/or more detailed transmission planning, cost or benefit information/component(s) that are applicable to/available for the proposed transmission project, the projects that would be displaced, and any additional projects required to implement the proposal.[15]

[15]The performance of this updated, detailed benefit-to-cost analysis might identify different Beneficiaries and/or Impacted Utilities than that identified in the initial benefit-to-cost analysis performed in accordance with Section 16.2.1.

16.4 Jurisdictional and/or Governance Authority Approval and Selection for RCAP: The project will be selected for RCAP in the then-current iteration of the regional plan for purposes of Order No. 1000, subject to the provisions of Section 18, if: (i) the detailed financial terms provided in accordance with Section 16.3, as may be modified by agreement of the transmission developer and Beneficiary(ies), are acceptable to each Beneficiary; (ii) the proposed transmission project is found to satisfy the more detailed benefit-to-cost analysis specified in Section 16.3; and (iii) if approval is obtained from all of the jurisdictional and/or governance authorities of the Impacted Utilities by the date specified in the schedule adopted in accordance with Section 16.2.2.[16] If obtaining jurisdictional and/or governance authorities approval requires a modification of the detailed financial terms found acceptable in Section 16.3, and both the transmission developer and the Beneficiary(ies) agree to the modification, then the modified detailed financial terms shall be the basis for the regional cost allocation for purposes of the project.

17. Cost Allocation Methodology Based Upon Avoided Transmission Costs: If a regional transmission project is selected in a regional plan for RCAP in accordance with Section 16.4 and then constructed and placed into service, the Beneficiaries identified in the detailed benefit-to-cost analysis performed in Section 16.3 to potentially have one or

[16]Being selected for RCAP in the then-current iteration of a regional plan only provides how the costs of the transmission project may be allocated in Commission-approved rates should the project be built. Being selected in a regional plan for RCAP provides no rights with regard to siting, construction, or ownership. The transmission developer must obtain all requisite approvals to site and build its transmission project. A transmission project may be removed from the selected category in a regional plan for RCAP in accordance with the provisions of Sections 15.4, 18 and 19.

more of their planned transmission projects displaced by the transmission developer's potential transmission project for RCAP will be allocated the regional transmission project's costs in proportion to their respective displaced transmission costs as found acceptable in accordance with Sections 16.3 and 16.4.

18. **On-Going Evaluations of Proposed Projects**: In order to ensure that the Transmission Provider can efficiently and cost effectively meet its respective reliability, duty to serve, and cost of service obligations, and to ensure that the proposed transmission project actually proves to be more efficient and cost effective, the Transmission Provider will continue to reevaluate a proposed transmission project, including any such projects that are being considered for potential selection in a regional plan for RCAP and any transmission projects that may have been selected in a regional plan for RCAP. This continued reevaluation will assess then-current transmission needs and determine whether the proposed transmission project continues to be needed and is more efficient and cost effective compared to alternatives as assessed in subsequent expansion planning processes that reflect ongoing changes in actual and forecasted conditions. Even though a proposed project may have been selected in a regional plan for RCAP in an earlier regional plan, if it is determined that the proposed project is no longer needed and/or it is no longer more efficient and cost effective than alternatives, then the Transmission Provider may notify the transmission developer and remove the proposed project from the selected category in a regional plan for RCAP. Reevaluation will occur until it is no longer reasonably feasible to replace the proposed transmission project as a result of the proposed transmission project being in a material stage of construction and/or if it is no longer considered reasonably feasible for an alternative transmission project to be placed in service in time to address the underlying transmission need(s) the proposed project is intended to address.

19. **Delay or Abandonment:** As part of the Transmission Provider's on-going transmission planning efforts, the Transmission Provider will assess whether alternative transmission solutions may be required in addition to, or in place of, a potential transmission project selected in a regional plan for RCAP due to the delay in its development or abandonment of the project. In this regard, the transmission developer shall promptly notify the Transmission Provider should any material changes or delays be encountered in the development of the potential transmission project. If, due to such delay or abandonment, the Transmission Provider determines that a project selected in a regional plan for RCAP no longer adequately addresses underlying transmission needs and/or no longer remains more efficient and cost effective, then the Transmission Provider may remove the project from being selected in a regional plan for RCAP and proceed with seeking appropriate solution(s). If removed from being selected in a regional plan for RCAP due to delay or abandonment by the transmission developer, then the transmission developer shall be responsible for, at a minimum, any increased costs to the Impacted Utilities due to any such delay or abandonment.

20. **Milestones of Required Steps Necessary to Maintain Status as Being Selected for RCAP**: Once selected in a regional plan for RCAP, the transmission developer must submit a development schedule to the Transmission Provider and the Impacted Utilities that establishes the milestones, including (to the extent not already accomplished) obtaining all necessary ROWs and requisite environmental, state, and other governmental approvals and executing a mutually-agreed upon contract(s) with the Beneficiaries, by

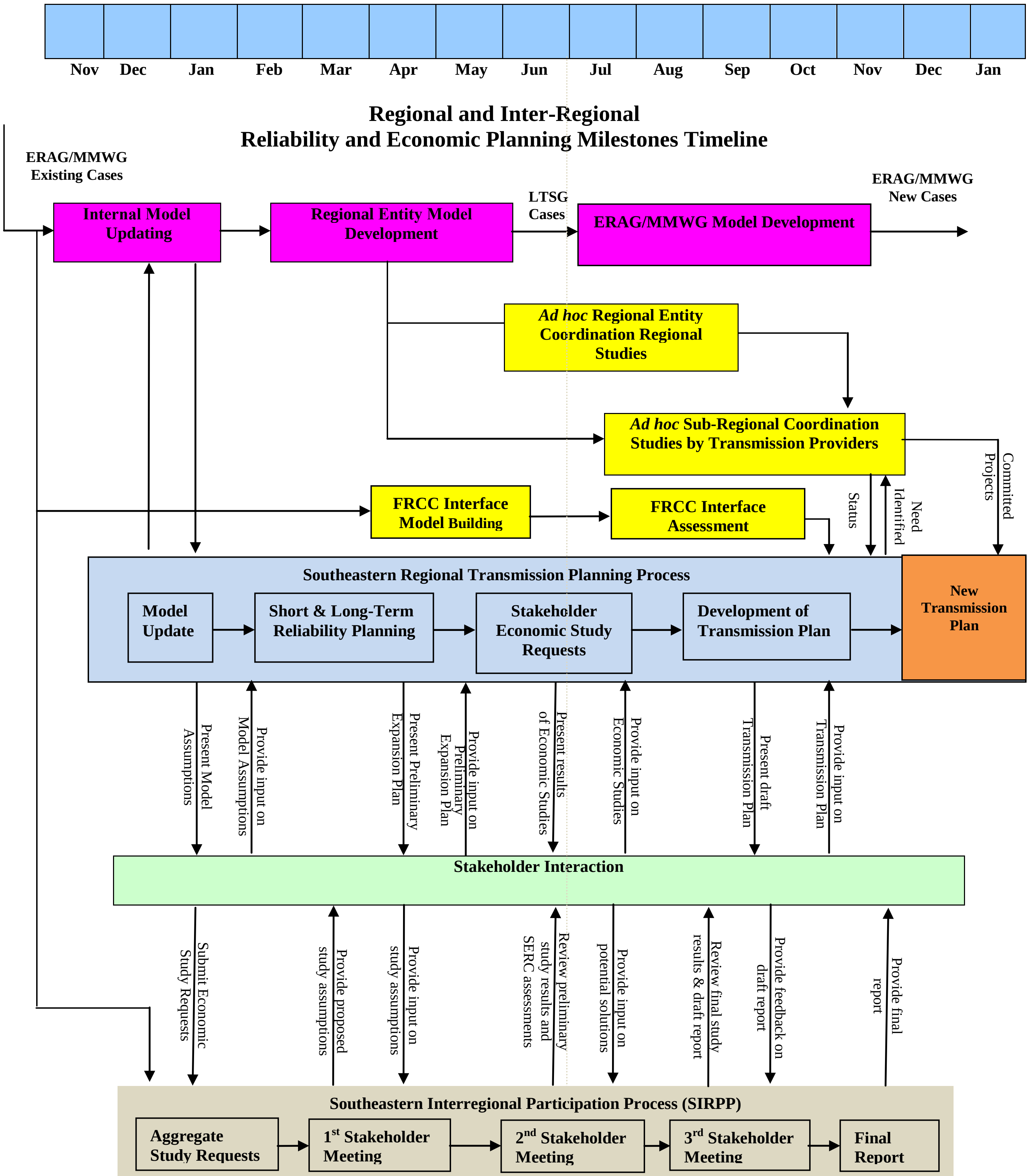
which the necessary steps to develop and construct the transmission project must occur. The schedule and milestones must be satisfactory to the Transmission Provider and the Impacted Utilities. In addition, the Transmission Provider and the Impacted Utilities will also determine the security/collateral arrangements for the proposed project and the deadline(s) by which they must be provided.[17] If such critical steps are not met by the specified milestones and then afterwards maintained, then the Transmission Provider may remove the project from the selected category in a regional plan for RCAP.

21. Mutually Agreed Upon Contract(s) Between the Transmission Developer and the Beneficiaries: The contract(s) referenced in Section 20 will address terms and conditions associated with the development of the proposed transmission project in a regional plan for RCAP, including:

1. The specific financial terms/specific total amounts to be charged by the transmission developer for the regional transmission project to the Beneficiaries, as agreed to by the parties,
2. The contracting Beneficiary's(ies') allocation of the costs of the aforementioned regional facility,
3. Creditworthiness/project security requirements,
4. Operational control of the regional transmission project,
5. Milestone reporting, including schedule of projected expenditures,
6. Engineering, procurement, construction, maintenance, and operation of the proposed regional transmission project,
7. Emergency restoration and repair responsibilities,
8. Reevaluation of the regional transmission project, and
9. Non-performance or abandonment.

[17]Satisfying the minimum, financial criteria specified in Section 13.1.2 alone in order to be eligible propose a project for RCAP will not satisfy this security/collateral requirement.

Exhibit K-3


Nov
Dec
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Jan
Regional and Inter-Regional
Reliability and Economic Planning Milestones Timeline
ERAG/MMWG Existing Cases
Internal Model Updating
Regional Entity Model Development
LTSG Cases
ERAG/MMWG Model Development
ERAG/MMWG New Cases
Ad hoc Regional Entity Coordination Regional Studies
Ad hoc Sub-Regional Coordination Studies by Transmission Providers
Committed Projects
FRCC Interface Model Building
FRCC Interface Assessment
Status
Need Identified
Southeastern Regional Transmission Planning Process
Model Update
Short & Long-Term Reliability Planning
Stakeholder Economic Study Requests
Development of Transmission Plan
New Transmission Plan
Present Model Assumptions
Provide input on Model Assumptions
Present Preliminary Expansion Plan
Provide input on Preliminary Expansion Plan
Present results of Economic Studies
Provide input on Economic Studies
Present draft Transmission Plan
Provide input on Transmission Plan
Stakeholder Interaction
Submit Economic Study Requests
Provide proposed study assumptions
Provide input on study assumptions
Review preliminary study results and SERC assessments
Provide input on potential solutions
Review final study results & draft report
Provide feedback on draft report
Provide final report
Southeastern Interregional Participation Process (SIRPP)
Aggregate Study Requests
1st Stakeholder Meeting
2nd Stakeholder Meeting
3rd Stakeholder Meeting
Final Report

ATTACHMENT K
The Southeastern Regional Transmission Planning Process

The Transmission Provider participates in the Southeastern Regional Transmission Planning Process ("SERTP") described herein and on the Regional Planning Website, a link to which is found on the Transmission Provider's OASIS. The other transmission providers and owners that participate in this Southeastern Regional Transmission Planning Process are identified on the Regional Planning Website ("Sponsors").[1] This Southeastern Regional Transmission Planning Process provides a coordinated, open and transparent planning process between the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers and other interested parties, including the coordination of such planning with interconnected systems within the region, to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and nondiscriminatory basis. The Transmission Provider's coordinated, open and transparent planning process is hereby provided in this Attachment K, with additional materials provided on the Regional Planning Website.

[1] The Transmission Provider notes that while this Attachment K discusses the Transmission Provider largely effectuating the activities of the Southeastern Regional Transmission Planning Process that are discussed herein, the Transmission Provider expects that the other Sponsors will also sponsor those activities. For example, while this Attachment K discusses the Transmission Provider hosting the Annual Transmission Planning Meetings, the Transmission Provider expects that it will be co-hosting such meetings with the other Sponsors. Accordingly, many of the duties described herein as being performed by the Transmission Provider may be performed in conjunction with one or more other Sponsors or may be performed entirely by one or more other Sponsors. Likewise, while this Attachment K discusses the transmission expansion plan of the Transmission Provider, the Transmission Provider expects that transmission expansion plans of the other Sponsors shall also be discussed, particularly since, at times, a single transmission expansion plan may be common to all Sponsors. To the extent that this Attachment K makes statements that might be construed to imply establishing duties or obligations upon other Sponsors, no such duty or obligation is intended. Rather, such statements are intended to only mean that it is the Transmission Provider's expectation that other Sponsors will engage in such activities. Accordingly, this Attachment K only establishes the duties and obligations of the Transmission Provider and the means by which Stakeholders may interact with the Transmission Provider through the Southeastern Regional Transmission Planning Process described herein.

Local Transmission Planning

The Transmission Provider has established the SERTP as its coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider plans its transmission system to reliably meet the needs of its transmission customers on a least-cost, reliable basis in accordance with applicable requirements of federal and state public utility laws and regulations. The Transmission Provider incorporates into its transmission plans the needs and results of the integrated resource planning activities conducted within each of its applicable state jurisdictions pursuant to its applicable duty to serve obligations. In accordance with the foregoing, its contractual requirements, and the requirements of NERC Reliability Standards, the Transmission Provider conducts comprehensive reliability assessments and thoroughly coordinates with neighboring and/or affected transmission providers.

As provided below, through its participation in the SERTP, the Transmission Provider's local planning process satisfies~~ As provided herein, the Southeastern Regional Transmission Planning Process addresses~~ the following nine principles, as defined in ~~the Final Rule in Docket~~Order No. ~~RM05-25-000~~890: coordination, openness, transparency, information exchange, comparability,[2] dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. This planning process also addresses at Section 9 the requirement to provide a mechanism for the recovery and allocation of planning costs consistent

[2]The Transmission Provider is committed to providing comparable and non-discriminatory transmission service. As such, comparability is not separately addressed in a stand-alone section of this Attachment K but instead permeates the Southeastern Regional Transmission Process described in this Attachment K.

with ~~the Final Rule in Docket No. RM05-25-000.~~Order No. 890. This planning process also includes at Section 10 the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements consistent with Order No. 1000. As provided below, the SERTP includes sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers for Attachment K purposes, which is set forth in Section 1 of this Attachment K;

(ii) The notice procedures and anticipated frequency of meetings; which is set forth in Sections 1 and 2 of this Attachment K;

(iii) The Transmission Provider's transmission planning methodology, criteria, and processes, which are set forth in Section 3 of this Attachment K;

(iv) The method of disclosure of transmission planning criteria, assumptions and underlying data, which is set forth in Sections 2 and 3 of this Attachment K;

(v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider, which is set forth in Section 4 of this Attachment K;

(vi) The dispute resolution process, which is set forth in Section 5 of this Attachment K;

(vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources, which is set forth in Section 7 of this Attachment K;

(viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000, which are set forth in Section 10 of this Attachment K; and

(ix) The relevant cost allocation method or methods, which is set forth in Section 8 of this Attachment K.

Regional Transmission Planning

The Transmission Provider participates in the SERTP through which transmission facilities and non-transmission alternatives may be proposed and evaluated. This regional transmission planning process develops a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region for purposes of Order No. 1000. This regional transmission planning process is consistent with the provision of Commission-jurisdictional services at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order No. 1000.

This regional transmission planning process satisfies the following seven principles, as set out and explained in Order Nos. 890 and 1000: coordination, openness, transparency, information exchange, comparability,[3] dispute resolution, and economic planning studies. This regional transmission planning process includes at Section 10 the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. This regional transmission planning process provides at Section 9 a mechanism for the recovery and allocation of planning costs consistent with Order No. 890. This regional transmission planning process includes at Section 12 a clear enrollment process for public and non-public utility transmission providers that make the choice to become part of a transmission planning region for purposes of regional cost allocation. This regional transmission planning process subjects enrollees to cost allocation if they are found to be beneficiaries of new transmission facilities selected in the regional transmission plan for purposes of cost allocation.

[3]The Transmission Provider is committed to providing comparable and non-discriminatory transmission service. As such, comparability is not separately addressed in a stand-alone section of this Attachment K but instead permeates the Southeastern Regional Transmission Process described in this Attachment K.

The list of enrolled entities to the SERTP is posted on the Regional Planning Website. The relevant cost allocation method or methods that satisfy the six regional cost allocation principles set forth in Order No. 1000 are described in Sections 16-17 of this Attachment K. Nothing in this regional transmission planning process includes an unduly discriminatory or preferential process for transmission project submission and selection. As provided below, the SERTP includes sufficient detail to enable Transmission Customers to understand:

(i) The process for enrollment and terminating enrollment in the SERTP, which is set forth in Section 12 of this Attachment K;

(ii) The process for consulting with customers, which is set forth in Section 1 of this Attachment K;

(iii) The notice procedures and anticipated frequency of meetings, which is set forth in Sections 1 and 2 of this Attachment K;

(iv) The Transmission Provider's transmission planning methodology, criteria, and processes, which are set forth in Section 3 of this Attachment K;

(v) The method of disclosure of transmission planning criteria, assumptions and underlying data, which is set forth in Sections 2 and 3 of this Attachment K;

(vi) The obligations of and methods for transmission customers to submit data, which are set forth in Section 4 of this Attachment K;

(vii) The process for submission of data by nonincumbent developers of transmission projects that wish to participate in the transmission planning process and seek regional cost allocation for purposes of Order No. 1000, which is set forth in Sections 13-21 of this Attachment K;

(viii) The process for submission of data by merchant transmission developers that wish to participate in the transmission planning process, which is set forth in Section 11 of this Attachment K;

(ix) The dispute resolution process, which is set forth in Section 5 of this Attachment K;

(x) The study procedures for economic upgrades to address congestion or the integration of new resources, which is set forth in Section 7 of this Attachment K;

(xi) The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000, which are set forth in Section 10 of this Attachment K; and

(xii) The relevant cost allocation method or methods satisfying the six regional cost allocation principles set forth in Order No. 1000, which is set forth at Sections 16-17.

ORDER NO. 890 TRANSMISSION PLANNING PRINCIPLES

~~Section~~ 1. Coordination

1.1 General: The Southeastern Regional Transmission Planning Process is designed to eliminate the potential for undue discrimination in planning by establishing appropriate lines of communication between the Transmission Provider, its transmission-providing neighbors, affected state authorities, Transmission Customers, and other Stakeholders regarding transmission planning issues.

1.2 Meeting Structure: Each calendar year, the Southeastern Regional Transmission Planning Process will generally conduct and facilitate four (4) meetings ("Annual Transmission Planning Meetings") that are open to all Stakeholders. However, the number of Annual Transmission Planning Meetings, or duration of any particular meeting, may be adjusted by announcement upon the Regional

Planning Website, provided that any decision to reduce the number of Annual Transmission Planning Meetings must first be approved by the Sponsors and by the Regional Planning Stakeholders' Group ("RPSG"). These meetings can be done in person, through phone conferences, or through other telecommunications or technical means that may be available. The details regarding any such meeting will be posted on the Regional Planning Website, with a projected meeting schedule for a calendar year being posted on the Regional Planning Website on or before December 31st of the prior calendar year, with firm dates for all Annual Transmission Planning Meetings being posted at least 60 calendar days prior to a particular meeting. The general structure and purpose of these four (4) meetings will be as follows:

1.2.1 First RPSG Meeting and Interactive Training Session: At this meeting, which will be held in the first quarter of each calendar year, the RPSG will be formed for purposes of that year. In addition, the Transmission Provider will meet with the RPSG and any other interested Stakeholders for the purposes of allowing the RPSG to select up to five (5) Stakeholder requested Economic Planning Studies that they would like to have studied by the Transmission Provider and the Sponsors. At this meeting, the Transmission Provider will work with the RPSG to assist the RPSG in formulating these Economic Planning Study requests. Requests that are inter-regional in nature will be addressed in the Southeast Inter-

[2]~~The Transmission Provider is committed to providing comparable and non-discriminatory transmission service. As such, comparability is not separately addressed in a stand-alone section of this Attachment K but instead permeates the Southeastern Regional Transmission Process described in this Attachment K.~~

Regional Participation Process. The Transmission Provider will also conduct an interactive training session regarding its transmission planning for all interested Stakeholders. This session will explain and discuss the underlying methodology and criteria that will be utilized to develop the transmission expansion plan[4] before that methodology and criteria are finalized for purposes of the development of that year's transmission expansion plan (*i.e.*, the expansion plan that will be implemented the following calendar year).~~[3]~~[5] Stakeholders may submit comments to the Transmission Provider regarding the Transmission Provider's criteria and methodology during the discussion at the meeting or within ten (10) business days after the meeting, and the Transmission Provider will consider such comments. Depending upon the major transmission planning issues presented at that time, the Transmission Provider will provide various technical experts that will lead the discussion of pertinent transmission planning topics, respond to Stakeholder questions, and provide technical guidance regarding transmission planning matters. It is foreseeable that it may prove appropriate to shorten the training sessions

[4] As indicated *infra* at footnote 1, references in this Attachment K to a transmission "plan," "planning," or "plans" should be construed in the singular or plural as may be appropriate in a particular instance. Likewise, the reference to a plan or plans may, depending upon the circumstance, be a reference to a regional transmission plan required for purposes of Order No. 1000. Moreover, the iterative nature of transmission planning bears emphasis, with underlying assumptions, needs, and data inputs continually changing to reflect market decisions, load service requirements, and other developments. A transmission plan, thus, only represents the status of transmission planning when the plan was prepared.

~~[3]~~[5] A transmission expansion plan completed during one calendar year (and presented to Stakeholders at that calendar year's Annual Transmission Planning Summit) is implemented the following calendar year. For example, the transmission expansion plan developed during 2009 and presented at the 2009 Annual Transmission Planning Summit is for the 2010 calendar year.

as Stakeholders become increasingly knowledgeable regarding the Transmission Provider's transmission planning process and no longer need detailed training in this regard.

The Transmission Provider will also address transmission planning issues that the Stakeholders may raise.

1.2.2 **Preliminary Expansion Plan Meeting:** During the second quarter of each calendar year, the Transmission Provider will meet with all interested Stakeholders to explain and discuss: the Transmission Provider's preliminary transmission expansion plan, which is also input into that year's SERC (or other applicable NERC region's) regional model; internal model updating and any other then-current coordination study activities with the transmission providers in the Florida Reliability Coordinating Council ("FRCC"); and any *ad hoc* coordination study activities that might be occurring. These preliminary transmission expansion plan, internal model updating, and coordination study activities will be described to the Stakeholders, with this meeting providing them an opportunity to supply their input and feedback, including the transmission plan/enhancement alternatives that the Stakeholders would like the Transmission Provider and the Sponsors to consider. In addition, the Transmission Provider will address transmission planning issues that the Stakeholders may raise and otherwise discuss with Stakeholders developments ~~at~~as part of the SERC (or other applicable NERC region's) reliability assessment process.

1.2.3 Second RPSG Meeting: During the third quarter of each calendar year, the Transmission Provider will meet with the RPSG and any other interested Stakeholders to report the preliminary results for the Economic Planning Studies requested by the RPSG at the First RPSG Meeting and Interactive Training Session. Study results that are inter-regional in nature will be reported to the RPSG and interested Stakeholders as they become available from the Southeast Inter-Regional Planning Participation Process. This meeting will give the RPSG an opportunity to provide input and feedback regarding those preliminary results, including alternatives for possible transmission solutions that have been identified. At this meeting, the Transmission Provider shall provide feedback to the Stakeholders regarding transmission expansion plan alternatives that the Stakeholders may have provided at the Preliminary Expansion Plan Meeting, or within a designated time following that meeting. The Transmission Provider will also discuss with the Stakeholders the results of the SERC (or other applicable NERC region's) regional model development for that year (with the Transmission Provider's input into that model being its ten (10) year transmission expansion plan); any on-going coordination study activities with the FRCC transmission providers; and any *ad hoc* coordination study activities. In addition, the

Transmission Provider will address transmission planning issues that the Stakeholders may raise.

1.2.4 Annual Transmission Planning Summit and Assumptions Input Meeting: During the fourth quarter of each calendar year, the Transmission Provider will host the annual Transmission Planning Summit and Assumptions Input Meeting.

1.2.4.1 Annual Transmission Planning Summit: At the Annual Transmission Planning Summit aspect of the Annual Transmission Planning Summit and Assumptions Input Meeting, the Transmission Provider will present the final results for the Economic Planning Studies. The results for such studies that are inter-regional in nature will be reported to the RPSG and interested Stakeholders as they become available from the Southeast Inter-Regional Planning Participation Process. The Transmission Provider will also provide an overview of the ten (10) year transmission expansion plan, the results of that year's coordination study activities with the FRCC transmission providers, and the results of any *ad hoc* coordination study activities. The Transmission Provider will also provide an overview of the regional transmission plan for Order No. 1000 purposes, which should include the ten (10) year transmission expansion plan of the Transmission Provider. In addition, the

Transmission Provider will address transmission planning issues that the Stakeholders may raise.

1.2.4.2 Assumptions Input Session: The Assumptions Input Session aspect of the Annual Transmission Planning Summit and Assumptions Input Meeting will take place following the annual Transmission Planning Summit and will provide an open forum for discussion with, and input from, the Stakeholders regarding: the data gathering and transmission model assumptions that will be used for the development of the Transmission Provider's following year's ten (10) year transmission expansion plan, which ~~comprises~~includes the Transmission Provider's input, to the extent applicable, into that year's SERC regional model development; internal model updating and any other then-current coordination study activities with the transmission providers in the Florida Reliability Coordinating Council ("FRCC"); and any *ad hoc* coordination study activities that might be occurring. This meeting may also serve to address miscellaneous transmission planning issues, such as reviewing the previous year's regional planning process, and to address specific transmission planning issues that may be raised by Stakeholders.

1.3 Committee Structure – the RPSG: To facilitate focused interactions and dialogue between the Transmission Provider and the Stakeholders regarding transmission planning, and to facilitate the development of the Economic Planning Studies, the RPSG was formed in March 2007. The RPSG has two primary purposes. First, the RPSG is charged with determining and proposing up to five (5) Economic Planning Studies on an annual basis and should consider clustering similar Economic Planning Study requests. The RPSG is also encouraged to coordinate with stakeholder groups in the area covered by the Southeast Inter-Regional Participation Process regarding requests for Economic Planning Studies that are inter-regional in nature. Second, the RPSG serves as the representative in interactions with the Transmission Provider and Sponsors for the eight (8) industry sectors identified below.

1.3.1 RPSG Sector Representation: The Stakeholders are organized into the following eight (8) sectors for voting purposes within the RPSG:

(1) Transmission Owners/Operators[~~3~~6]

(2) Transmission Service Customers

(3) Cooperative Utilities

(4) Municipal Utilities

(5) Power Marketers

(6) Generation Owners/Developers

(7) ISO/RTOs

(8) Demand Side Management/Demand Side Response

[~~3~~6] The Sponsors will not have a vote within the Transmission Owners/Operators sector, although they (or their affiliates, subsidiaries or parent company) shall have the right to participate in other sectors.

1.3.2 Sector Representation Requirements: Representation within each sector is limited to two members, with the total membership within the RPSG being capped at 16 members ("Sector Members"). The Sector Members, each of whom must be a Stakeholder, are elected by Stakeholders, as discussed below. A single company, and all of its affiliates, subsidiaries, and parent company, is limited to participating in a single sector.

1.3.3 Annual Reformulation: The RPSG will be reformed annually at each First RPSG Meeting and Interactive Training Session discussed in Section 1.2.1. Specifically, the Sector Members will be elected for a term of approximately one year that will terminate upon the convening of the following year's First RPSG Meeting and Interactive Training Session. Sector Members shall be elected by the Stakeholders physically present at the First RPSG Meeting and Interactive Training Session (voting by sector for the respective Sector Members). If elected, Sector Members may serve consecutive, one-year terms, and there is no limit on the number of terms that a Sector Member may serve.

1.3.4 Simple Majority Voting: RPSG decision-making that will be recognized by the Transmission Provider for purposes of this Attachment K shall be those authorized by a simple majority vote by the then-current Sector Members, with voting by proxy being permitted for a Sector Member that is unable to attend a particular meeting. The Transmission Provider will notify the RPSG of the matters upon which an RPSG vote is required and will use reasonable efforts to identify upon the Regional Planning Website the matters for which an RPSG decision by simple majority vote is required prior to the vote, recognizing that developments might occur at a particular Annual Transmission Planning Meeting for which an RPSG vote is required but that could not be reasonably foreseen in advance. If the RPSG is unable to achieve a majority vote, or should the RPSG miss any of the deadlines prescribed herein or clearly identified on the Regional Planning Website and/or at a particular meeting to take any action, then the Transmission Provider will be relieved of any obligation that is associated with such RPSG action.

1.3.5 RPSG Guidelines/Protocols: The RPSG is a self-governing entity subject to the following requirements that may not be altered absent an appropriate filing with the Commission to amend this aspect of the Tariff: (i) the RPSG shall consist of the above-specified eight (8) sectors; (ii) each company, its affiliates, subsidiaries, and parent company, may only participate in a single sector; (iii) the RPSG shall be reformed annually, with the Sector Members serving terms of a single year; and (iv) RPSG decision-making shall be by a simple majority vote (*i.e.*, more than 50%) by the Sector Members, with voting by written proxy being recognized for a Sector Member unable to attend a particular meeting. There are no formal incorporating documents for the RPSG, nor are there formal agreements between the RPSG and the Transmission Provider. As a self-governing entity, to the extent that the RPSG desires to adopt other internal rules and/or protocols, or establish subcommittees or other structures, it may do so provided that any such rule, protocol, etc., does not conflict with or otherwise impede the foregoing requirements or other aspects of the Tariff. Any such additional action by the RPSG shall not impose additional burdens upon the Transmission Provider unless it agrees in advance to such in writing, and the costs of any such action shall not be borne or otherwise imposed upon the Transmission Provider unless the Transmission Provider agrees in advance to such in writing.

1.4 The Role of the Transmission Provider in Coordinating the Activities of the Southeastern Regional Transmission Planning Process Meetings and of the Functions of the RPSG: The Transmission Provider will host and conduct the above-described Annual Transmission Planning Meetings with Stakeholders.[4][7]

1.5 Procedures Used to Notice Meetings and Other Planning-Related Communications: Meetings notices, data, stakeholder questions, reports, announcements, registration for inclusion in distribution lists, means for being

[4][7] As previously discussed, the Transmission Provider expects that the other Sponsors will also be hosts and sponsors of these activities.

certified to receive Critical Energy Infrastructure Information ("CEII"), and other transmission planning-related information will be posted on the Regional Planning Website. Stakeholders will also be provided notice regarding the annual meetings by e-mail messages (if they have appropriately registered on the Regional Planning Website to be so notified). Accordingly, interested Stakeholders may register on the Regional Planning Website to be included in e-mail distribution lists ("Registered Stakeholder"). For purposes of clarification, a Stakeholder does not have to have received certification to access CEII in order to be a Registered Stakeholder.

1.6 Procedures to Obtain CEII Information: For access to information considered to be CEII, there will be a password protected area that contains such CEII information. Any Stakeholder may seek certification to have access to this CEII data area.

1.7 The Regional Planning Website: The Regional Planning Website will contain information regarding the Southeastern Regional Transmission Planning Process, including:

- Notice procedures and e-mail addresses for contacting the Sponsors and for questions;
- A calendar of meetings and other significant events, such as release of draft reports, final reports, data, etc.;
- A registration page that allows Stakeholders to register to be placed upon an e-mail distribution list to receive meetings notices and other announcements electronically; and
- The form in which meetings will occur (*i.e.*, in person, teleconference, webinar, *etc*.).

~~Section~~ 2. Openness

2.1 **General:** The Annual Transmission Planning Meetings, whether consisting of in-person meetings, conference calls, or other communicative mediums, will be open to all Stakeholders. The Regional Planning Website will provide announcements of upcoming events, with Stakeholders being notified regarding the Annual Transmission Planning Meetings by such postings. In addition, Registered Stakeholders will also be notified by e-mail messages. Should any of the Annual Transmission Planning Meetings become too large or otherwise become unmanageable for the intended purpose(s), smaller breakout meetings may be utilized.

2.2 **Links to OASIS:** In addition to open meetings, the publicly available information, CEII-secured information (the latter of which is available to any Stakeholder certified to receive CEII), and certain confidential non-CEII information (as set forth below) shall be made available on the Regional Planning Website, a link to which is found on the Transmission Provider's OASIS website, so as to further facilitate the availability of this transmission planning information on an open and comparable basis.

2.3 **CEII Information**

2.3.1 **Criteria and Description of CEII:** The Commission has defined CEII as being specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that:

1. Relates details about the production, generation, transmission, or distribution of energy;

2. Could be useful to a person planning an attack on critical infrastructure;

3. Is exempt from mandatory disclosure under the Freedom of Information Act; and

4. Does not simply give the general location of the critical infrastructure.

2.3.2 **Secured Access to CEII Data:** The Regional Planning Website will have a secured area containing the CEII data involved in the Southeastern Regional Transmission Planning Process that will be password accessible to Stakeholders that have been certified to be eligible to receive CEII data. For CEII data involved in the Southeastern Regional Transmission Planning Process that did not originate with the Transmission Provider, the duty is incumbent upon the entity that submitted the CEII data to have clearly marked it as CEII.

2.3.3 **CEII Certification:** In order for a Stakeholder to be certified and be eligible for access to the CEII data involved in the Southeastern Regional Transmission Planning Process, the Stakeholder must follow the CEII certification procedures posted on the Regional Planning Website (*e.g.*, authorize background checks and execute the SERTP CEII Confidentiality Agreement posted on the Regional Planning Website). The Transmission Provider reserves the discretionary right to waive the certification process, in whole or in part, for anyone that the Transmission Provider deems appropriate to receive CEII information. The Transmission Provider also reserves the discretionary right to reject a request for CEII; upon such rejection, the requestor may pursue the dispute resolution procedures of Section 5.

2.3.4 Discussions of CEII Data at the Annual Transmission Planning Meetings: While the Annual Transmission Planning Meetings are open to all Stakeholders, if CEII information is to be discussed during a portion of such a meeting, those discussions will be limited to being only with those Stakeholders who have been certified eligible to have access to CEII information, with the Transmission Provider reserving the discretionary right at such meeting to certify a Stakeholder as being eligible if the Transmission Provider deems it appropriate to do so.

2.4 Other Sponsor- and Stakeholder- Submitted Confidential Information: The other Sponsors and Stakeholders that provide information to the Transmission Provider that foreseeably could implicate transmission planning should expect that such information will be made publicly available on the Regional Planning Website or may otherwise be provided to Stakeholders in accordance with the terms of this Attachment K. Should another Sponsor or Stakeholder consider any such information to be CEII, it shall clearly mark that information as CEII and bring that classification to the Transmission Provider's attention at, or prior to, submittal. Should another Sponsor or Stakeholder consider any information to be submitted to the Transmission Provider to otherwise be confidential (*e.g.*, competitively sensitive), it shall clearly mark that information as such and notify the Transmission Provider in writing at, or prior to, submittal, recognizing that any such designation shall not result in any material delay in the development of the transmission expansion plan or any other transmission plan that the Transmission Provider (in whole or in part) is required to produce.

2.5 Procedures to Obtain Confidential Non-CEII Information

2.5.1 The Transmission Provider shall make all reasonable efforts to preserve the confidentiality of information in accordance with the provisions of the Tariff, the requirements of (and/or agreements with) NERC, the requirements of (and/or agreements with) ~~the SERC Reliability Corporation ("SERC")~~ SERC or other applicable NERC region, the provisions of any agreements with the other Sponsors and/or with the sponsors of the Southeast Inter-Regional Participation Process ("SIRPP"), and/or in accordance with any other contractual or legal confidentiality requirements.

2.5.2 [RESERVED]

2.5.3 [RESERVED]

2.5.4 Without limiting the applicability of Section 2.5.1, to the extent competitively sensitive and/or otherwise confidential information (other than information that is confidential solely due to its being CEII) is provided in the transmission planning process and is needed to participate in the transmission planning process and to replicate transmission planning studies, it will be made available to those Stakeholders who have executed the SERTP Non-CEII Confidentiality Agreement (which agreement is posted on the Regional Planning Website). Importantly, if information should prove to contain both competitively sensitive/otherwise confidential information and CEII, then the requirements of both Section 2.3 and Section 2.5 would apply.

2.5.5 Other transmission planning information shall be posted on the Regional Planning Website and may be password protected, as appropriate.

~~Section 3~~3. Transparency

3.1 **General:** Through the Annual Transmission Planning Meetings and postings made on the Regional Planning Website, the Transmission Provider will disclose to its Transmission Customers and other Stakeholders the basic criteria, assumptions, and data that underlie its transmission system plan, as well as information regarding the status of upgrades identified in the transmission plan. The process for notifying stakeholders of changes or updates in the data bases used for transmission planning shall be through the Annual Transmission Planning Meetings and/or by postings on the Regional Planning Website.

3.2 **The Availability of the Basic Methodology, Criteria, and Process the Transmission Provider Uses to Develop its Transmission Plan:** In an effort to enable Stakeholders to replicate the results of the Transmission Provider's transmission planning studies, and thereby reduce the incidences of after-the-fact disputes regarding whether transmission planning has been conducted in an unduly discriminatory fashion, the Transmission Provider will provide the following information, or links thereto, on the Regional Planning Website:

(1) The Electric Reliability Organization and Regional Entity reliability standards that the Transmission Provider utilizes, and complies with, in performing transmission planning.

(2) The Transmission Provider's internal policies, criteria, and guidelines that it utilizes in performing transmission planning.

(3) Current software titles and version numbers used for transmission analyses by the Transmission Provider.

Any additional information necessary to replicate the results of the Transmission Provider's planning studies will be provided in accordance with, and subject to, the CEII and confidentiality provisions specified in this Attachment K and Exhibit K-2.

3.3 Additional Transmission Planning-Related Information: In an effort to facilitate the Stakeholders' understanding of the Transmission System, the Transmission Provider will also post additional transmission planning-related information that it deems appropriate on the Regional Planning Website.

3.4 Additional Transmission Planning Business Practice Information: In an effort to facilitate the Stakeholders' understanding of the Business Practices related to Transmission Planning, the Transmission Provider will also post the following information on the Regional Planning Website:

(1) Means for contacting the Transmission Provider.

(2) Procedures for submittal of questions regarding transmission planning to the Transmission Provider (in general, questions of a non-immediate nature will be collected and addressed through the Annual Transmission Planning Meeting process).

(3) Instructions for how Stakeholders may obtain transmission base cases and other underlying data used for transmission planning.

(4) Means for Transmission Customers having Service Agreements for Network Integration Transmission Service to provide load and resource assumptions to the Transmission Provider; provided that if there are specific means defined in a Transmission Customer's Service Agreement for Network Integration Transmission Service ("NITSA") or its corresponding Network Operating Agreement ("NOA"), then the NITSA or NOA shall control.

(5) Means for Transmission Customers having Long-Term Service Agreements for Point-To-Point Transmission Service to provide to the Transmission Provider projections of their need for service over the planning horizon (including any potential rollover periods, if applicable), including transmission capacity, duration, receipt and delivery points, likely redirects, and resource assumptions; provided that if there are specific means defined in a Transmission Customer's Long-Term Transmission Service Agreement for Point-To-Point Transmission Service, then the Service Agreement shall control.

3.5 Transparency Provided Through the Annual Transmission Planning Meetings

3.5.1 The First RPSG Meeting and Interactive Training Session

3.5.1.1 An Interactive Training Session Regarding the Transmission Provider's Transmission Planning Methodologies and Criteria: As discussed in (and subject to) Section 1.2.1, at the First RPSG Meeting and Interactive

Training Session, the Transmission Provider will, among other things, conduct an interactive, training and input session for the Stakeholders regarding the methodologies and criteria that the Transmission Provider utilizes in conducting its transmission planning analyses. The purpose of these training and interactive sessions is to facilitate the Stakeholders' ability to replicate transmission planning study results to those of the Transmission Provider.

3.5.1.2 Presentation and Explanation of Underlying Transmission Planning Study Methodologies: During the training session in the First RPSG Meeting and Interactive Training Session, the Transmission Provider will present and explain its transmission study methodologies. While not all of the following methodologies may be addressed at any single meeting, these presentations may include explanations of the methodologies for the following types of studies:

1. Steady state thermal analysis.
2. Steady state voltage analysis.
3. Stability analysis.
4. Short-circuit analysis.
5. Nuclear plant off-site power requirements.
6. Interface analysis (*i.e.*, import and export capability).

3.5.2 Presentation of Preliminary Modeling Assumptions: At the Annual Transmission Planning Summit, the Transmission Provider will also provide to the Stakeholders its preliminary modeling assumptions for the development of the Transmission Provider's following year's ten (10) year transmission expansion plan. This information will be made available on the Regional Planning Website, with CEII information being secured by password access. The preliminary modeling assumptions that will be provided may include:

1. Study case definitions, including load levels studied and planning horizon information.
2. Resource assumptions, including on-system and off-system supplies for current and future native load and network customer needs.
3. Planned resource retirements.
4. Renewable resources under consideration.
5. Demand side options under consideration.
6. Long-term firm transmission service agreements.
7. Current TRM and CBM values.

3.5.3 The Transmission Expansion Review and Input Process: The Annual Transmission Planning Meetings will provide an interactive process over a calendar year for the Stakeholders to receive information and updates, as well as to provide input, regarding the Transmission Provider's development of its transmission expansion plan. This dynamic process will generally be provided as follows:

1. At the Annual Transmission Planning Summit and Assumptions Input Meeting, the Transmission Provider will describe and explain to the Stakeholders the database assumptions for the ten (10) year transmission expansion plan that will be developed during the upcoming year. The Stakeholders will be allowed to provide input regarding the ten (10) year transmission expansion plan assumptions.

2. At the First RPSG Meeting and Interactive Training Session, the Transmission Provider will provide interactive training to the Stakeholders regarding the underlying criteria and methodologies utilized to develop the transmission expansion plan. The databases utilized by the Transmission Provider will be posted on the secured area of the Regional Planning Website.

3. To the extent that Stakeholders have transmission expansion plan/enhancement alternatives that they would like for the Transmission Provider and other Sponsors to consider, the Stakeholders shall perform analysis prior to, and provide any such analysis at, the Preliminary Expansion Plan Meeting. At the Preliminary Expansion Plan Meeting, the Transmission Provider will present its preliminary transmission expansion plan for the current ten (10) year planning horizon. The Transmission Provider

and Stakeholders will engage in interactive expansion plan discussions regarding this preliminary analysis. This preliminary transmission expansion plan will be posted on the secure/CEII area of the Regional Planning Website at least 10 calendar days prior to the Preliminary Expansion Plan meeting.

4. The transmission expansion plan/enhancement alternatives suggested by the Stakeholders will be considered by the Transmission Provider for possible inclusion in the transmission expansion plan. When evaluating such proposed alternatives, the Transmission Provider will, from a transmission planning perspective, take into account factors such as, but not limited to, the proposed alternatives' impacts on reliability, relative economics, effectiveness of performance, impact on transmission service (and/or cost of transmission service) to other customers and on third-party systems, project feasibility/viability and lead time to install.

5. At the Second RPSG Meeting, the Transmission Provider will report to the Stakeholders regarding the suggestions/alternatives suggested by the Stakeholders at the Preliminary Expansion Plan Meeting. The then-current version of the transmission expansion plan will be posted on the secure/CEII area of the regional planning website at least 10 calendar days prior to the Second RPSG Meeting.

6. At the Annual Transmission Planning Summit, the ten (10) year transmission expansion plan that will be implemented the following year will be presented to the Stakeholders. The Transmission Planning Summit presentations and the (10) year transmission expansion plan will be posted on the Regional Planning Website at least 10 calendar days prior to the Annual Transmission Planning Summit.

3.5.4 Flowchart Diagramming the Steps of the Southeastern Regional Transmission Planning Process: A flowchart diagramming the Southeastern Regional Transmission Planning Process, as well as providing the general timelines and milestones for the performance of the reliability planning activities described in Section 6 to this Attachment K, is provided in Exhibit K-3.

~~Section 4~~4. Information Exchange

4.1 General: Transmission Customers having Service Agreements for Network Integration Transmission Service are required to submit information on their projected loads and resources on a comparable basis (*e.g.*, planning horizon and format) as used by transmission providers in planning for their native load. Transmission Customers having Service Agreements for Point-To-Point Transmission Service are required to submit any projections they have a need for service over the planning horizon and at what receipt and delivery points. Interconnection Customers having Interconnection Agreements under the Tariff are required to submit projected changes to their generating facility that could impact the Transmission Provider's performance of transmission planning studies. The purpose of this information that is provided by each class of customers is to facilitate the Transmission Provider's transmission planning process, with the September 1 due date of these data submissions by customers being timed to facilitate the Transmission Provider's development of its databases and model building for the following year's ten (10) year transmission expansion plan.

4.2 **Network Integration Transmission Service Customers:** By September 1 of each year, each Transmission Customer having Service Agreement[s] for Network Integration Transmission Service shall provide to the Transmission Provider an annual update of that Transmission Customer's Network Load and Network Resource forecasts for the following ten (10) years consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff.

4.3 **Point-to-Point Transmission Service Customers:** By September 1 of each year, each Transmission Customers having Service Agreement[s] for long-term Firm Point-To-Point Transmission Service shall provide to the Transmission Provider usage projections for the term of service. Those projections shall include any projected redirects of that transmission service, and any projected resells or reassignments of the underlying transmission capacity. In addition, should the Transmission Customer have rollover rights associated with any such service agreement, the Transmission Customer shall also provide non-binding usage projections of any such rollover rights.

4.4 **Demand Resource Projects:** The Transmission Provider expects that Transmission Customers having Service Agreements for Network Integration Transmission Service that have demand resource assets will appropriately reflect those assets in those customers' load projections. Should a Stakeholder have a demand resource asset that is not associated with such load projections that the Stakeholder would like to have considered for purposes of the transmission expansion plan, then the Stakeholder shall provide the necessary information *(e.g.* technical and operational characteristics, affected loads, cost, performance, lead time to install) in order for the Transmission Provider to consider such demand response resource comparably with other alternatives. The Stakeholder shall provide this information to the Transmission Provider by the Annual Transmission Planning Summit and Assumptions Input Meeting of the year prior to the implementation of the pertinent ten (10) year transmission expansion plan, and the Stakeholder should then continue to participate in this Southeastern Regional Transmission Planning Process. To the extent similarly situated, the Transmission Provider shall treat such Stakeholder submitted demand resource projects on a comparable basis for transmission planning purposes.

4.5 **Interconnection Customers:** By September 1 of each year, each Interconnection Customer having an Interconnection Agreement[s] under the Tariff shall provide to the Transmission Provider annual updates of that Interconnection Customer's planned addition or upgrades (including status and expected in-service date), planned retirements, and environmental restrictions.

4.6 Notice of Material Change: Transmission Customers and Interconnection Customers shall provide the Transmission Provider with timely written notice of material changes in any information previously provided related to any such customer's load, resources, or other aspects of its facilities, operations, or conditions of service materially affecting the Transmission Provider's ability to provide transmission service or materially affecting the Transmission System.

~~Section 5~~5. Dispute Resolution

5.1 Negotiation: Any substantive or procedural dispute between the Transmission Provider and one or more Stakeholders (collectively, the "Parties") that arises from the Attachment K transmission planning process generally shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the pertinent Stakeholder(s) for resolution on an informal basis as promptly as practicable. Should the dispute also involve one or more other Sponsors of this Southeastern Regional Transmission Planning Process or other Participating Transmission Owners of the Southeast Inter-Regional Participation Process, then such entity(ies) shall have the right to be included in "Parties" for purposes of this section and for purposes of that dispute, and any such entity shall also include a designated senior representative in the above discussed negotiations in an effort to resolve the dispute on an informal basis as promptly as practicable. In the event that the designated representatives are unable to resolve the dispute within thirty (30) days, or such other period as the Parties may unanimously agree upon, by unanimous agreement among the Parties such dispute may be voluntarily submitted to the use of the Commission's Alternative Means of Dispute

Resolution (18 C.F.R. § 385.604, as those regulations may be amended from time to time), the Commission's Arbitration process (18 C.F.R. § 385.605, as those regulations may be amended from time to time) (collectively, "Commission ADR"), or such other dispute resolution process that the Parties may unanimously agree to utilize.

5.2 **Use of Dispute Resolution Processes:** In the event that the Parties voluntarily and unanimously agree to the use of a Commission ADR process or other dispute resolution procedure, then the Transmission Provider will have a notice posted to this effect on the Regional Planning Website, and an e-mail notice in that regard will be sent to Registered Stakeholders. In addition to the Parties, all Stakeholders and Sponsors shall be eligible to participate in any Commission ADR process as "participants", as that or its successor term in meaning is used in 18 C.F.R. §§ 385.604, 385.605 as may be amended from time to time, for purposes of the Commission ADR process; provided, however, any such Stakeholder or Sponsor must first have provided written notice to the Transmission Provider within thirty (30) calendar days of the posting on the Regional Planning Website of the Parties' notice of their intent to utilize a Commission ADR Process.

5.3 **Costs:** Each Party involved in a dispute resolution process hereunder, and each "participant" in a Commission ADR Process utilized in accordance with Section 5.2, shall be responsible for its own costs incurred during the dispute resolution process. Should additional costs be incurred during the dispute resolution process that are not directly attributable to a single Party/participant, then the Parties/participants shall each bear an equal share of such cost.

5.4 **Rights under the Federal Power Act:** Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

~~Section 6~~6. **Regional Participation**[8]

6.1 **General:** The Transmission Provider coordinates with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources.

6.2 **Coordination within the ~~other Sponsors~~SERTP:** The Transmission Provider coordinates ~~with the other Sponsors~~ through this Southeastern Regional Transmission Planning Process with the other transmission providers and owners within this region and the corresponding meetings, communications, and data and information exchanges. ~~The Sponsors are identified on the Regional Planning Website.~~ The particular activities that are coordinated are the annual preparation of this region's ten (10) year transmission expansion plans and the preparation of the Economic Planning Studies addressed in Section 7 below. The transmission, generation, and demand resource transmission expansion plan/enhancement alternatives suggested by the Stakeholders pursuant to Section 3.5.3(3) will be considered in regional studies conducted to improve the reliability of the bulk

[8] In accordance with Order No. 1000, this planning principle only applies to the Transmission Provider's local transmission planning process.

power system and this information will be shared with the other ~~Sponsors~~transmission owners in this region.

6.3 Coordination with the Other Participating Transmission Owners in the Southeast Inter-Regional Participation Process: On an inter-regional basis, the Transmission Provider coordinates with the transmission systems with which the Transmission Provider is interconnected, with the exception of the utilities in the Florida Reliability Coordination Council ("FRCC"), through the Southeast Inter-Regional Participation Process ("SIRPP") attached hereto as Exhibit K-2 and incorporated herein by reference, and the corresponding meetings, communications, and data and informational exchanges. In that regard, a link to the SIRPP website is found on the Transmission Provider's OASIS. The transmission owners participating in the SIRPP are identified on the SIRPP website ("SIRPP Sponsors"). The particular activities that the SIRPP sponsors coordinate are the preparation of the inter-regional Economic Planning Studies addressed in Section 7 below and in Exhibit K-2, and the review with stakeholders of the data, assumptions, and assessment activities that are then being conducted on a SERC-wide basis.

6.4 Coordination with Other SERC Members: The Transmission Provider is a member of the SERC Reliability Corporation ("SERC") and coordinates with other SERC members in reliability transmission planning. At least as of December 17, 2008, the SERC members are identified on SERC's website. SERC is the regional entity responsible for promoting the reliability and adequacy of the bulk power system in the area served by its member systems. SERC has in place various committees and subcommittees, whose members are employees of SERC members, to perform those functions, including the promotion of the reliability and adequacy of the bulk power system as related to the planning and engineering of the electric systems. At least as of December 17, 2008, the SERC committees are identified on SERC's website. Through these committee processes, the particular transmission planning activities that are coordinated with the SERC members are the creation of a SERC regional model and the preparation of a simultaneous feasibility assessment, which are discussed in further detail below.

6.5 Coordination with the Transmission Owners in the FRCC

6.5.1 Reliability Coordination with the Transmission Owners in the FRCC: As discussed in Exhibit K-2, seams coordination for the SIRPP occurs at the regional level where external planning processes adjoin the SIRPP. In that regard, the Transmission Provider coordinates with the transmission providers in the FRCC through a reliability coordination arrangement for the purpose of safeguarding and augmenting the reliability of the Transmission Provider's Transmission System and that of the FRCC. This arrangement provides for exchanges of information and system data between the Transmission Provider and the FRCC transmission providers for the coordination of planning and operations in the interest of reliability. This arrangement also provides the mechanism for regional studies and recommendations designed to improve the reliability of the interconnected bulk power system. Duties under the arrangement are as follows: (1) coordination of generation and transmission system planning, construction, operating, and protection to maintain maximum reliability; (2) coordination of interconnection lines and facilities for full implementation of mutual assistance in emergencies; (3) initiation of joint studies and investigations pertaining to the reliability of bulk power supply facilities; (4) coordination of maintenance schedules of generating units and transmission lines; (5) determination of requirements for necessary communication between the parties; (6) coordination of load relief measures and restoration procedures; (7) coordination of spinning reserve requirements; (8) coordination of voltage levels and reactive power supply; (9) other matters relating to the reliability of bulk power supply required to meet customer service requirements; and (10) exchange of necessary information, such as magnitude and characteristics of actual and forecasted loads, capability of generating facilities, programs of capacity additions, capability of bulk power interchange facilities, plant and system emergencies, unit outages, and line outages.

6.5.2 Economic Planning Studies with the FRCC: The Transmission Provider and the FRCC have developed procedures for the performance of Economic Planning Studies that are selected by their Stakeholders through their respective Attachment K transmission planning processes for bulk power transfers that involve both the FRCC and the Transmission Provider. Those procedures are posted on the Regional Planning Website (including the FRCC/SERTP process for requesting inter-regional economic studies and a description of how information, modeling data and expansion plans are shared).

6.6 Reliability Planning Process

6.6.1 General: The Transmission Provider's reliability planning process with ~~both the Sponsors and with~~ the transmission providers and owners participating in the SERTP and SIRPP is described in documentation posted on the Regional Website and the Inter-Regional Website.

6.6.2 A Description of How the Various Reliability Study Processes Interact with Each Other: The reliability planning process in the Southeast is a "bottom-up" process. Specifically, the Transmission Provider's 10-year transmission expansion plan is the base case that it uses for reliability planning processes, with it being the Transmission Provider's input into the development of the SERC regional model. In addition, the results of the FRCC coordination activities and of any *ad hoc* coordination activities are incorporated into the Transmission Provider's transmission expansion plan. These processes are discussed further below on both (a) a local and regional level (*e.g.* Southeastern Regional Transmission Planning level) and (b) an inter-regional (*e.g.* SERC-wide level).

(a)(i) **~~Regional~~Bottom-up Reliability Planning:** The bulk of the substantive transmission planning in the Southeast occurs as transmission owners, such as the Transmission Provider, develop their reliability transmission expansion plans. In this regard, the

Transmission Provider's reliability plan~~ for each Attachment K region (such as that comprising this Southeastern Regional Transmission Planning Process)~~ is generally developed by determining the required 10-year transmission expansion plan to satisfy load, resources, and transmission service commitments throughout the 10-year reliability planning horizon. The development of ~~each regional~~the Transmission Provider's reliability plan is facilitated through the creation of transmission models (base cases) that incorporate the current ten (10) year transmission expansion plan, load projections, resource assumptions (generation, demand response**,** and imports), and transmission service commitments within the region. The transmission models also incorporate external regional models (at a minimum the current SERC models) that are developed using similar information.

(a)(ii) **~~Regional~~Bottom-Up Reliability Study Process:** The transmission models created for use in developing the ~~regional~~transmission provider's reliability 10-year transmission expansion plan are analyzed to determine if any planning criteria concerns (including, at a minimum, North American Electric Reliability Corporation ("NERC") planning criteria) are projected. In the event one or more planning criteria concerns are identified~~ at the regional level~~, the transmission owners will develop solutions for these projected limitations. As a part of this study process, the transmission owners will reexamine the current regional reliability 10-year transmission expansion plans (determined through the previous year's regional reliability planning process) to determine if the current plan can be enhanced based on the updated assumptions and any new planning criteria concerns identified in the analysis. The enhancement process may include the deletion and/or modification to any of the existing reliability transmission enhancements identified in the previous year's reliability planning process.

(a)(iii) **Identification of ~~Regional~~ Reliability Transmission Enhancements**: Once a planning criteria concern is identified or the enhancement process identifies the potential for a superior solution, the transmission owner will then determine if any neighboring planning process is potentially impacted by the projected limitation. Potentially impacted ~~regions~~transmission owners are then contacted to determine if there is a need for an ~~inter-regional~~ *ad hoc* coordinated study. In the event one or more neighboring ~~region agrees~~transmission owners agree that they would be impacted by the projected limitation or identifies the potential for a superior ~~inter-regional~~ reliability solution based on transmission enhancements in their current ~~regional~~ reliability plan, an ~~inter-regional~~ *ad hoc* coordinated study is initiated. Once the study has been completed, the identified reliability transmission enhancements will then be incorporated into the ~~region's(s')~~ ten (10) year transmission expansion plan (*i.e.*, the plan due to be impl~~a~~emented the following year) as a reliability project.

(b)(i) **~~Inter-Regional (~~SERC-Wide~~)~~ Assessments and ~~Inter-Regional~~ Planning Activities**: After ~~the regional~~their transmission models are developed, the transmission owners within SERC create a SERC-wide transmission model and conduct a long-term reliability assessment. The intent of the SERC-wide reliability assessment is to determine if the different~~ regional~~ reliability transmission expansion plans are simultaneously feasible and to otherwise ensure that the transmission owners are using consistent models and data. Additionally, the reliability assessment measures and reports transfer capabilities between regions and transmission owners within SERC. The SERC-wide assessment serves as a valuable tool for each of the transmission owners to reassess the need for additional~~ inter-regional~~ reliability joint studies.

(b)(ii) **SERC Transmission Model Development:** The construction of the SERC transmission model is a "bottom-up" process. In particular, SERC transmission models are developed by the transmission owners in SERC through an annual model development process. Each transmission owner in SERC, incorporating input from their regional planning process, develops and submits their 10-year transmission models to a model development databank, with the models and the databank then being used to create a SERC-wide model for use in the reliability assessment. Additionally, the SERC-wide models are then used in ~~each regional~~the SERTP planning process as an update (if needed) to the current transmission models and as a foundation (along with the Multiregional Modeling Working Group ("MMWG") models) for the development of the transmission provider's transmission models for the following year.

(b)(iii) **Additional~~ Inter-Regional~~ Reliability Joint Studies:** As mentioned above, the SERC-wide reliability assessment serves as a valuable tool for the transmission owners to reassess the need for additional~~ inter-regional~~ reliability joint studies. If the SERC-wide reliability model projects additional planning criteria concerns that were not identified in the ~~regional~~transmission owners' reliability studies, then the impacted transmission owners will initiate one or more *ad hoc* inter-regional coordinated study(ies) (in accordance with existing Reliability Coordination Agreements) to better identify the planning criteria concerns and determine inter-regional reliability transmission enhancements to resolve the limitations. Once the study(ies) is completed, required reliability transmission enhancements will be incorporated into the ~~region~~Transmission Provider's ten (10) year expansion plan as a reliability project. Accordingly, planning criteria concerns identified at the SERC-wide level are "pushed down" to the transmission owner level for detailed resolution.

~~6.6.4~~6.6.3 A Description of How Stakeholders May Participate in These Processes

(a)(i) **Participation Through the Southeastern Regional Transmission Planning Process:** Since the bulk of the reliability transmission planning occurs~~ at the regional level~~ as a "bottom up" process in the development of the Transmission Provider's ten (10) year transmission expansion plan, Stakeholders may participate in these reliability planning processes by participating in the Southeastern Regional Transmission Planning Process. Specifically, the ten (10) year transmission expansion plan is the Transmission Provider's input into the SERC model development, and the results of the FRCC coordination and of any *ad hoc* coordination studies are incorporated into the ten (10) year transmission expansion plan. As discussed in Section 1.2.2, at the Preliminary Expansion Plan Meeting, Stakeholders are provided the opportunity to review and comment (and allowed to propose alternatives concerning enhancements found in): the Transmission Provider's preliminary transmission expansion plan, which is the

Transmission Provider's input into (1) SERC's regional model development, (2) coordination with the FRCC, and (3) any *ad hoc* coordination activities. As discussed in Section 1.2.3, at the Second RPSG Meeting, the Stakeholders are provided feedback regarding the expansion plan alternatives that they submitted at the First RPSG Meeting and are provided an overview of the results of the SERC regional model development for that year, as well as the results of any on-going coordination activities with the FRCC transmission providers and any *ad hoc* coordination activities. As discussed in Section 1.2.4, at the Annual Transmission Planning Summit and Assumptions Input Section, the Stakeholders are provided an overview of the ten (10) year transmission expansion plan, the results of that year's coordination study activities with the FRCC transmission providers, and the results of any *ad hoc* coordination activities. In addition, Stakeholders are provided an open forum regarding: the data gathering and transmission model assumptions that will be used for purposes of the ten (10) year transmission expansion plan to be developed the following year (which will constitute the Transmission Provider's input into the SERC regional model development for the following year); FRCC model development; and any *ad hoc* coordination studies.

(a)(ii) **Participation Through the SIRPP:** As shown on the Southeast Inter-Regional Participation Process Diagram contained in Exhibit

K-2, the particular activities that the SIRPP sponsors coordinate are the preparation of the inter-regional Economic Planning Studies addressed in Section 7 below and in Exhibit K-2. In addition, the SIRPP sponsors will review with stakeholders the data, assumptions, and assessment that are then being conducted on a SERC-wide basis at: the 1st Inter-Regional Stakeholder Meeting; the 2nd Inter-Regional Stakeholder Meeting; and the 3rd Inter-Regional Stakeholder Meeting.

(a)(iii) **Membership in SERC**: Interested Stakeholders may further participate in SERC processes by seeking to become a member of SERC. At least as of December 17, 2008, the requirements to become a SERC member are specified on SERC's website.

6.7 Timeline and Milestones: The general timelines and milestones for the performance of the reliability planning activities are provided in Exhibit K-3, which also provides a flowchart diagramming the steps of the Southeastern Regional Transmission Planning Process.

~~Section 7~~7. Economic Planning Studies

7.1 General – Economic Planning Study Requests: Stakeholders will be allowed to request that the Transmission Provider perform up to five (5) Stakeholder requested economic planning studies ("Economic Planning Studies") on an annual basis. Requests that are inter-regional in nature will be addressed in the SIRPP. Accordingly, it is expected that the RPSG will coordinate with other inter-regional stakeholders regarding Economic Planning Studies that are inter-regional in nature.

7.2 Parameters for the Economic Planning Studies: These Economic Planning Studies shall be confined to sensitivity requests for bulk power transfers and/or to evaluate potential upgrades or other investments on the Transmission System that could reduce congestion or integrate new resources. Bulk power transfers from one area to another area with the region encompassed by this Southeastern Regional Transmission Planning Process (the "Region") shall also constitute valid requests. The operative theory for the Economic Planning Studies is for them to identify meaningful information regarding the requirements for moving large amounts of power beyond that currently feasible, whether such transfers are internal to the Region or from this Region to interconnected regions. It should again be noted that requests that are inter-regional in nature will be addressed in the SIRPP.

7.3 Other Tariff Studies: The Economic Planning Studies are not intended to replace System Impact Studies, Facility Studies, or any of the studies that are performed for transmission delivery service or interconnection service under the Tariff.

7.4 Clustering: The RPSG should consider clustering similar Economic Planning Study requests. In this regard, if two or more of the RPSG requests are similar in nature and the Transmission Provider concludes that clustering of such requests and studies is appropriate, the Transmission Provider may, following communications with the RPSG, cluster those studies for purposes of the transmission evaluation. It is foreseeable that clustering of requests may occur during the SIRPP.

7.5 Additional Economic Planning Studies: Should a Stakeholder(s) request the performance of an Economic Planning Study in addition to the above-described five (5) Economic Planning Studies that the RPSG may request during a calendar year, then any such additional Economic Planning Study will only be performed if such Stakeholder(s) first agrees to bear the Transmission Provider's actual costs for doing so and the costs incurred by any other Sponsor to perform such Economic Planning Study, recognizing that the Transmission Provider may only conduct a reasonable number of transmission planning studies per year. If affected by the request for such an additional Economic Planning Study, the Transmission Provider will provide to the requesting Stakeholder(s) a non-binding but good faith estimate of what the Transmission Provider expects its costs to be to perform the study prior to the Stakeholder(s) having to agree to bear those costs. Should the Stakeholder(s) decide to proceed with the additional study, then it shall pay the Transmission Provider's and other affected Sponsor[s]' estimated study costs up-front, with those costs being trued-up to the Transmission Provider's and other affected Sponsor[s]' actual costs upon the completion of the additional Economic Planning Study.

7.6 Economic Planning Study Process

1. Stakeholders will be prompted at the Annual Transmission Planning Summit to provide requests for the performance of Economic Planning Studies. Corresponding announcements will also be posted on the

Regional Planning Website, and Registered Stakeholders will also receive e-mail notifications to provide such requests. An Economic Planning Study Request Form will be made available on the Regional Planning Website, and interested Stakeholders may submit any such completed request form on the non-secure area of the Regional Planning Website (unless such study request contains CEII, in which case the study request shall be provided to the Transmission Provider with the CEII identified, and the study request shall then be posted on the secure area of the Regional Planning Website).

2. Prior to each First RPSG Meeting, the RPSG shall compile the Economic Planning Study requests. At the First RPSG Meeting, the RPSG shall meet to discuss and select up to five (5) Economic Planning Studies to be requested to be performed. At the First RPSG Meeting, the Transmission Provider will coordinate with the RPSG and any interested Stakeholders to facilitate the RPSG's efforts regarding its development and selection of the Economic Planning Study requests. Once the RPSG selects the Economic Planning Study(ies) (up to five annually), the RPSG will notify the Transmission Provider, who will post the results on the Regional Planning Website.

3. The Transmission Provider will post on the secure area of the Regional Planning Website the study assumptions for the five (5) Economic Planning Studies within thirty (30) days of the postings of the selected Economic Planning Studies on the Regional Planning Website. Registered

Stakeholders will receive an e-mail notification of this posting, and an announcement will also be posted on the Regional Planning Website.

4. Stakeholders will have thirty (30) calendar days from the Transmission Provider's posting of the assumptions for the RPSG to provide comments regarding those assumptions. Any such comments shall be posted on the secure area of the Regional Planning Website if the comments concern CEII.

5. The preliminary results of the Economic Planning Studies will be presented at the Second RPSG Meeting. These results and related data will be posted on the secure area of the Regional Planning Website a minimum of 10 calendar days prior to the Second RPSG Meeting. Study results that are inter-regional in nature will be reported to the RPSG and interested Stakeholders and posted as they become available from the SIRPP. The Second RPSG Meeting will be an interactive session with the RPSG and other interested Stakeholders in which the Transmission Provider will explain the results, alternatives, methodology, criteria, and related considerations pertaining to those preliminary results. At that meeting, the Stakeholders may submit alternatives to the enhancement solutions identified in those preliminary results. All such alternatives must be submitted by Stakeholders within thirty (30) calendar days from the close of the Second RPSG Meeting. The Transmission Provider will consider the alternatives provided by the Stakeholders.

6. The final results of the Economic Planning Studies will be presented at the Annual Transmission Planning Summit, and the Transmission Provider will report regarding its consideration of the alternatives provided by Stakeholders. These final results will be posted on the secure area of the Regional Planning Website a minimum of 10 calendar days prior to the Transmission Planning Summit. Study results that are inter-regional in nature will be reported to the RPSG and interested Stakeholders and posted as they become available from the SIRPP.

7. The final results of the Economic Planning Studies will be non-binding upon the Transmission Provider and will provide general non-binding estimations of the required transmission upgrades, timing for their construction, and costs for completion.

~~**Section 8**~~

8. Order No. 890 Cost Allocation Principle[9]

8.1 General: The following provides the Transmission Provider's methodologies for allocating the costs of new transmission facilities that do not fit under the general Tariff rate structure under two scenarios. The first methodology addresses the allocation of the costs of economic transmission upgrades that are identified in the Economic Planning Studies and that are not otherwise associated with transmission service provided under the Tariff and are not associated with the provision of transmission service under other arrangements, such as the Transmission Provider's provision of bundled service to its Native Load Customers. The second methodology addresses upgrades that are not required to satisfy the Transmission Provider's planning standards and/or ERO or RE reliability standards, and thus would not otherwise be included in the transmission expansion plan, but that a Stakeholder, including a Transmission Customer, may want to have installed to provide additional reliability benefits above those necessary to satisfy the Transmission Provider's planning criteria and/or ERO or RE reliability standards ("Enhanced Reliability Upgrades").

8.2 Cost Allocation Methodology for Economic Upgrades

8.2.1 Identification of Economic Upgrades: The transmission expansion plan will identify the transmission upgrades that are necessary to ensure the reliability of the Transmission System and to otherwise meet the needs of long-term firm transmission service commitments ("Reliability

[9] In accordance with Order No. 1000, this planning principle only applies to the Transmission Provider's local transmission planning process.

Upgrades") in accordance with the Transmission Provider's planning standards and/or ERO or RE reliability standards. All of the upgrades identified in the Economic Planning Studies that are not identified in the transmission expansion plan, and are thus not such Reliability Upgrades, shall constitute "Economic Upgrades".

8.2.2 Request for Performance of Economic Upgrades: Within thirty (30) calendar days of the posting of the final results of the underlying Economic Planning Study[ies], one or more entities ("Initial Requestor[s]") that would like the Transmission Provider to construct one or more Economic Upgrades identified in the Economic Planning Study[ies] may submit a request for the Transmission Provider to construct such Economic Upgrade[s]. The Initial Requestor[s] should identify the percentage of cost responsibility for the Economic Upgrade[s] that the Initial Requestor[s] is requesting cost responsibility. The request must consist of a completed request application, the form of which will be posted on the Regional Planning Website ("Economic Upgrade Application"). The Transmission Provider will post the request on the secure area of the Regional Planning Website. Other entities ("Subsequent Requestor[s]") that also would like the Transmission Provider to construct the Economic Upgrade[s] sought by the Initial Requestor[s] shall notify the Transmission Provider of its intent, along with the percentage of cost responsibility that the Subsequent Requestor[s] is requesting cost responsibility, by following the instructions specified on the Regional Planning Website within thirty (30) calendar days of the Initial Requestor[s]' posting of its Economic Upgrade Application on the Regional Planning Website (collectively, the Initial Requestor[s] and the Subsequent Requestor[s] shall be referred to as the "Requestor[s]").

8.2.3 Allocation of the Costs of the Economic Upgrades: The costs of the Economic Upgrades shall be allocated to each Requestor based upon the percentage of cost responsibility that it has requested in its respective request. Should the total amount of percentage requests for cost responsibility for the Economic Upgrade[s] by the Requestors not equal one-hundred percent (100%), regardless if the requested amount is less than or exceeds one-hundred percent (100%), then the Requestor[s]' cost responsibility will be adjusted on a pro rata basis based upon the total percentage identified by all of the Requestor[s] relative to one-hundred percent (100%) so that all of the cost responsibility for the Economic Upgrade[s] is allocated to the Requestor[s]. If one or more of the Requestors do not identify the percentage of cost responsibility for which it is requesting cost responsibility, then the Requestors shall bear the costs of the Economic Upgrade[s] in equal shares based upon the number of Requestors. The Requestor[s] shall bear cost responsibility for the actual costs of the Economic Upgrades. Should a Requestor later not enter into an agreement with the Transmission Provider for the construction of the Economic Upgrade[s], then the remaining Requestor[s]' cost responsibility will be recalculated on a pro rata basis based upon the percentage of cost responsibility requested or based upon the remaining number of Requestor[s] if that methodology was used to allocate the Economic Upgrade[s]' costs.

8.2.4 **Cost Allocation for the Acceleration, Expansion, Deferral, or Cancellation of Reliability Upgrades:** Should the Transmission Provider conclude that the construction of an Economic Upgrade[s] would accelerate the construction of, or require the construction of a more expansive, Reliability Upgrade, then the Requestor[s] shall bear the costs of such acceleration or expansion. Should the Transmission Provider conclude that the construction of the Economic Upgrade[s] would result in the deferral or cancellation of a Reliability Upgrade, then the costs of the Economic Upgrade[s] allocated to the Requestor[s] shall be reduced by the present value of the amount of savings caused by the deferral or cancellation.

8.2.5 Implementing Agreements and Regulatory Approvals: The Transmission Provider will not be obligated to commence design or construction of any Economic Upgrade until (i) a binding agreement[s] with all of the Requestor[s] for such construction by the Transmission Provider and payment by the Requestor[s] of its allocated cost responsibility (in accordance with Section 8.2.3 above) is executed by the Transmission Provider, all other affected Sponsor[s], and all of the Requestor[s]; (ii) all of the Requestor[s] provide (and maintain, subject to reduction as set forth in (iii) below) the Transmission Provider security, in a form acceptable to the Transmission Provider, for the full costs of the design and construction; and (iii) appropriate commitments to construct are in place for all affected third party transmission providers (*e.g.*, other Sponsors). In addition, the Transmission Provider shall not be obligated to commence any phase of design or construction of any Economic Upgrade unless the Requestor[s] has first paid to the Transmission Provider in immediately available funds via wire transfer the Transmission Provider's estimated costs for that phase of design or construction (it being understood that security provided under (ii) above may be reduced on a dollar-for-dollar basis with respect to such payments received by Transmission Provider as and when they are final and are no longer subject to being voided or set aside), with the Requestor[s] bearing the actual costs of design and construction upon completion of the Economic Upgrade[s] pursuant to a true-up to the estimated costs already paid. Furthermore, the Transmission Provider shall not be obligated to commence construction, or to continue construction, if all necessary regulatory approvals are not obtained or maintained, with the Transmission Provider having to make a good faith effort to obtain all such approvals. The costs associated with obtaining and maintaining such regulatory approvals shall be included in the total costs of the Economic Upgrades and shall otherwise be borne by the Requestors.

8.3 Cost Allocation Methodology for Enhanced Reliability Upgrades

8.3.1 Enhanced Reliability Upgrades: The transmission expansion plan will identify the Reliability Upgrades, which are the transmission upgrades that are necessary to ensure the reliability of the Transmission System and to otherwise meet the needs of long-term firm transmission service commitments in accordance with the Transmission Provider's planning standards and/or ERO or RE reliability standards. Should one or more Stakeholders, including a Transmission Customer, determine that it wants an upgrade installed to provide additional reliability benefits above those necessary to satisfy the Transmission Provider's planning criteria and/or ERO or RE reliability standards (*i.e.*, an Enhanced Reliability Upgrade), then the costs of any such Enhanced Reliability Upgrade shall be directly assigned to that Stakeholder[s] ("Requesting Stakeholder[s]") without the provision of transmission credits or other means of reimbursement from the Transmission Provider for such direct assignment costs.

8.3.2 Cost Allocation of the Direct Assignment Costs Should Multiple Stakeholders Desire the Same Enhanced Reliability Upgrade: Should multiple Stakeholders want the installation and construction of the same Enhanced Reliability Upgrade[s], then the direct assignment costs for such Enhanced Reliability Upgrade[s] shall be allocated to those Requesting Stakeholders in equal shares, unless those Requesting Stakeholders agree in writing to a different cost allocation approach prior to the Transmission Provider assigning those costs.

8.3.3 Implementing Agreements and Regulatory Approvals: The Transmission Provider will not be obligated to commence design or construction of any Enhanced Reliability Upgrade until (i) a binding agreement[s] with the Requesting Stakeholder[s] for such construction by the Transmission Provider and payment by the Requesting Stakeholder[s] of its direct assignment costs (in accordance with Sections 8.3.1 and 8.3.2 above) is executed by the Transmission Provider and all of the Requesting Stakeholders seeking the construction of such Enhanced Reliability Upgrade[s] and (ii) all of the Requesting Stakeholder[s] provide (and maintain, subject to reduction as set forth in the following sentence) the Transmission Provider security, in a form acceptable to the Transmission Provider, for the full costs of the design and construction. In addition, the Transmission Provider shall not be obligated to commence any phase of design or construction of any Enhanced Reliability Upgrade unless the Requesting Stakeholder[s] has first paid to the Transmission Provider in immediately available funds via wire transfer the Transmission Provider's estimated costs for that phase of design or construction (it being understood that security provided under (ii) above may be reduced on a dollar-for-dollar basis with respect to such payments received by Transmission Provider as and when they are final and are no longer subject to being voided or set aside), with the Requesting Stakeholder[s] bearing the actual costs of design and construction upon completion of the ~~Economic~~Enhanced Reliability Upgrade[s] pursuant to a true-up to the estimated costs already paid. Furthermore, the Transmission Provider shall not be obligated to commence construction, or to continue construction, if all necessary regulatory approvals are not obtained or maintained, with the Transmission Provider having to make a good faith effort to obtain all such approvals. The costs associated with obtaining and maintaining such regulatory approvals shall be included in the total costs of the Enhanced Reliability Upgrade[s] and shall otherwise be borne by the Requesting Stakeholder[s].

~~**Section 9**~~**9.** **Recovery of Planning Costs:** With the exception of the costs to perform more than five Economic Planning Studies (which will be directly assigned to the requestor), the Transmission Provider will recover the costs that it incurs in implementing its requirements under this Southeastern Regional Transmission Planning Process by adding those costs to the Annual Charge costs that it recovers under Informational Schedule D in the Tariff.

TRANSMISSION PLANNING AND COST ALLOCATION REQUIREMENTS OF ORDER NO. 1000

10. Consideration of Transmission Needs Driven by Public Policy Requirements

10.1 Procedures for the Consideration of Transmission Needs Driven by Public Policy Requirements: The Transmission Provider addresses transmission needs driven by enacted state and federal laws and/or regulations ("Public Policy Requirements") in its routine planning, design, construction, operation, and maintenance of the Transmission System. In this regard, the Transmission

Provider addresses transmission needs driven by the Public Policy Requirements of load serving entities and wholesale transmission customers through the planning for and provision of long-term firm transmission services to meet i) native load obligations and ii) wholesale Transmission Customer obligations under the Tariff.

10.2 The Consideration of Transmission Needs Driven by Public Policy Requirements Identified Through Stakeholder Input and Proposals

10.2.1 Requisite Information: In order for the Transmission Provider to consider transmission needs driven by Public Policy Requirements that are proposed by a Stakeholder, the Stakeholder must provide the following information via a submittal to the Regional Planning Website:

1. The applicable Public Policy Requirement, which must be a requirement established by an enacted state or federal law(s) and/or regulation(s); and

2. An explanation of the possible transmission need driven by the Public Policy Requirement identified in the immediately above subsection (1) (*e.g.*, the situation or system condition for which possible solutions may be needed, as opposed to a specific transmission project) and an explanation and/or demonstration that the current iteration of the transmission expansion plan(s) does not adequately address that need.

10.2.2 Deadline for Providing Such Information: Stakeholders that propose a transmission need driven by a Public Policy Requirement for evaluation by the Transmission Provider in the current transmission planning cycle must provide the requisite information identified in Section 10.2.1 to the Transmission Provider no later than 60 calendar days after the SERTP

Annual Transmission Planning Summit and Input Assumptions Meeting for the previous transmission planning cycle. That information is to be provided in accordance with the contact information provided on the Regional Planning Website.

10.3 Transmission Provider Evaluation of SERTP Stakeholder Input Regarding Potential Transmission Needs Driven by Public Policy Requirements

10.3.1 In the transmission planning process for that planning cycle, the Transmission Provider will evaluate Stakeholder input to determine if there is a transmission need driven by the Public Policy Requirement identified by the Stakeholder in Section 10.2 that should be addressed in the transmission expansion plan.

10.3.2 If a transmission need is identified that is not already addressed in the transmission expansion planning process, the Transmission Provider will identify a transmission solution to address the aforementioned need in the planning processes.

10.3.3 Stakeholder input regarding potential transmission needs driven by Public Policy Requirements may be directed to the governing Tariff process as appropriate. For example, if the potential transmission need identified by the Stakeholder is essentially a request by a network customer to integrate a new network resource, the request would be directed to that existing Tariff process.

10.4 Posting Requirement: The Transmission Provider will provide and post on the Regional Planning Website a response to Stakeholder input regarding transmission needs driven by Public Policy Requirements.

11. Merchant Transmission Developers Proposing Transmission Facilities Impacting the SERTP: Merchant transmission developers not seeking regional cost allocation pursuant to Sections 15-21 ("Merchant Transmission Developers") who propose to develop a transmission project(s) potentially impacting the Transmission System and/or transmission system(s) within the SERTP region shall provide information and data necessary for the Transmission Provider to assess the potential reliability and operational impacts of those proposed transmission facilities. That information should include:

- Transmission project timing, scope, network terminations, load flow data, stability data, HVDC data (as applicable), and other technical data necessary to assess potential impacts.

12. Enrollment

12.1 General Eligibility for Enrollment: A public utility or non-public utility transmission service provider and/or transmission owner having a statutory or tariff obligation to ensure that adequate transmission facilities exist within a portion of the SERTP region may enroll in the SERTP. Such transmission providers and transmission owners are thus potential beneficiaries for cost allocation purposes on behalf of their transmission customers. Entities that do not enroll will nevertheless be permitted to participate as stakeholders in the SERTP.

12.2 Enrollment Requirement In Order to Seek Regional Cost Allocation: While enrollment is not generally required in order for a transmission developer to be eligible to propose a transmission project for evaluation and potential selection in a regional plan for regional cost allocation purposes ("RCAP") pursuant to Sections 15-21, a potential transmission developer must enroll in the SERTP in order to be eligible to propose a transmission project for potential selection in a regional plan for RCAP if it, an affiliate, subsidiary, member, owner or parent company has load in the SERTP.

12.3 Means to Enroll: A public utility or non-public utility transmission service provider or transmission owners may provide an application to enroll in accordance with Sections 12.1 and 12.2 above, by executing the form of enrollment posted on the Regional Planning Website. The Transmission Provider is deemed to have enrolled for purposes of Order No. 1000 through this Attachment K.

12.4 List of Enrollees in the SERTP: The Transmission Provider will post and keep current on the Regional Planning Website a list of the public utility and non-public utility transmission service providers and transmission owners who have enrolled in the SERTP ("Enrollees").

12.5 Enrollment, Cost Allocation Responsibility, and Conditions Subsequent: Enrollment will subject Enrollees to cost allocation if, during the period in which they are enrolled, it is determined in accordance with this Attachment K that the Enrollee is a beneficiary of a new transmission project(s) selected in the regional transmission plan for RCAP; provided that, once enrolled, should the Commission, a Court, or any other governmental entity having the requisite authority modify, alter, or impose amendments to this Attachment K, then an enrolled non-public utility may immediately withdraw from this Attachment K by providing written notice within 60 days of that order or action, with the non-public utility's termination being effective as of the close of business the prior business day before said modification, alteration, or amendment occurred. The withdrawing Enrollee will be subject to regional and interregional cost allocations, if any, to which it had agreed and that were determined in accordance with this Attachment K during the period in which it was enrolled and was determined to be a beneficiary of new transmission facilities selected in the regional transmission plan for RCAP. Any withdrawing Enrollee will not be allocated costs for projects selected in a regional transmission plan for RCAP after its termination of enrollment becomes effective in accordance with the provisions of this Section 12.5.

12.6 Notification of Withdrawal: An Enrollee wanting to terminate its enrollment in the SERTP may do so by providing written notification of such intent to the Transmission Provider. Except for non-public utilities terminating pursuant to Section 12.5 above, the termination will be effective at the end of the then-current transmission planning cycle provided that the notification of withdrawal is provided to the Transmission Provider at least sixty (60) days prior to the Annual Transmission Planning Summit and Assumptions Input Meeting for that transmission planning cycle. The withdrawing Enrollee will be subject to regional and interregional cost allocations, if any, to which it had agreed and that were determined in accordance with this Attachment K during the period in which it was enrolled and was determined to be a beneficiary of new transmission facilities selected in the regional transmission plan for purposes of cost allocation.

Any withdrawing Enrollee will not be allocated costs for projects selected in a regional transmission plan for RCAP after its termination of enrollment becomes effective in accordance with the provisions of this Section 12.6.

13. Qualification Criteria to Submit a Regional Transmission Project Proposal for Potential Selection in a Regional Transmission Plan for Purposes of Cost Allocation

13.1 Transmission Developer Qualification Criteria: While additional financial and technical criteria may be required to be satisfied in order for a proposed transmission project to be selected and/or included in a regional plan for RCAP, a transmission developer must satisfy the following, initial qualification criteria to be eligible to propose a transmission project for potential selection in a regional transmission plan for RCAP.[10]

13.1.1 If the transmission developer or its parent or owner or any affiliate, member or subsidiary has load in the SERTP region, the transmission developer must have enrolled in the SERTP in accordance with Section 12.2.

13.1.2 In order to be eligible to propose a transmission project for consideration for selection in a regional plan for RCAP, the transmission developer must demonstrate that it satisfies the following, minimum financial capability and technical expertise requirements:

1. The transmission developer has and maintains a credit rating of BBB- or higher from Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P"), or a credit rating of Baa3 or higher from

[10]The regional cost allocation process provided hereunder in accordance with Sections 13-21 does not undermine the ability of the Transmission Provider and other entities to negotiate alternative cost sharing arrangements voluntarily and separately from this regional cost allocation method.

Moody's Investors Service, Inc. In addition, the transmission developer's parent company's credit rating may be used to satisfy this requirement but only if the parent company commits in writing to provide a guaranty for the transmission developer if the proposed transmission project is selected in a regional plan for RCAP;[11]

2. The transmission developer provides documentation of its capability to finance U.S. energy projects equal to or greater than the cost of the proposed transmission project; and

3. The transmission developer has the capability to develop, construct, operate, and maintain U.S. electric transmission projects of similar or larger complexity, size, and scope as the proposed project. The transmission developer must demonstrate such capability by providing, at a minimum, the following information:

   a. A summary of the transmission developer's: transmission projects in-service, under construction, and/or abandoned or otherwise not completed including locations, operating voltages, mileages, development schedules, and approximate installed costs; whether delays in project completion were encountered; and how these facilities are owned, operated and maintained. This may include projects and experience provided by a parent company or affiliates or other experience relevant to the development of the proposed project; and

   b. If it or a parent, owner, affiliate, or member has been found in violation of any NERC and/or Regional Entity reliability standard and/or the violation of regulatory requirement(s) pertaining to the development, construction, ownership, operation, and/or maintenance of electric infrastructure facilities, an explanation of such violations.

14. Transmission Facilities Potentially Eligible for RCAP: In order for a transmission project proposed by a transmission developer to be considered for evaluation and potential selection in a regional plan for RCAP, the project must be regional in nature in that it must be a major transmission project effectuating significant bulk electric transfers across

[11] If a project is selected in a regional plan for RCAP, having a BBB- and/or a Baa3 rating alone will not be sufficient to satisfy the requisite project security/collateral requirements.

the SERTP region and addressing significant electrical needs. A regional transmission project eligible for potential selection in a regional plan for RCAP would be a transmission line that would:

a. operate at a voltage of 300 kV or greater and span 100 miles or more within the SERTP; and

b. portions of said transmission line must be located in two or more balancing authority areas located in the SERTP.

1. A transmission project that does not satisfy (a) and (b) above but that would effectuate similar, significant bulk electric transfers across the SERTP region and address similar, significant regional electrical needs will be considered on a case-by-case basis;

2. The proposed transmission project cannot be an upgrade to an existing facility. In addition, the proposed transmission project cannot be located on the property and/or right-of-way ("ROW") belonging to anyone other than the transmission developer absent the consent of the owner of the existing facility or ROW, as the case may be;

3. In order for the proposed transmission project to be a more efficient and cost effective alternative to the projects identified by the transmission providers through their planning processes, it should be materially different than projects already under consideration and materially different than projects that have been previously considered in the expansion planning process; and

4. The proposed transmission project must be able to be constructed and tied into the transmission system by the required in-service date.

15. Submission and Evaluation of Proposals for Potential Selection in a Regional Transmission Plan for RCAP

15.1 Information to be Submitted: A transmission developer must submit the following information in support of a transmission project it proposes for potential selection in a regional transmission plan for RCAP:

1. Documentation of the transmission developer's ability to satisfy the qualification criteria required in Section 13;

2. Sufficient information for the Transmission Provider to determine that the potential transmission project satisfies the regional eligibility requirements of Section 14;

3. If it or a parent, owner, affiliate, or member who will be performing work in connection with the potential transmission project is registered with NERC or other industry organizations pertaining to electric reliability and/or the development, construction, ownership, or operation, and/or maintenance of electric infrastructure facilities, a list of those registrations.

4. A description of the proposed transmission project that details the intended scope (including the various stages of the project development such as engineering, ROW acquisition, construction, recommended in-service date, etc.);

5. A capital cost estimate of the proposed transmission project. If the cost estimate differs greatly from generally accepted estimates of projects of comparable scope, the transmission developer will be required to support such differences;

6. Documentation of the technical analysis performed supporting the position that the proposed transmission project addresses the transmission needs and does so more efficiently and cost-effectively than specific projects included in the latest transmission expansion plan. Documentation must include the following:

   - The identification of: (a) transmission projects in the latest expansion plan that would be displaced by the proposed project, and (b) any additional projects that may be required in order to implement the proposed project; and

   - The data and/or files necessary to evaluate the transmission developer's analysis of the proposed transmission project;

7. The transmission developer must provide a reasonable explanation of, as it pertains to its proposed project, its planned approach to satisfy applicable regulatory requirements and its planned approach to obtain requisite authorizations necessary to acquire rights of way and to construct, operate, and maintain the proposed facility in the relevant jurisdictions;

   - The transmission developer should not expect to use the Transmission Provider's right of eminent domain for ROW acquisition; and

8. An administrative fee of $25,000 to off-set the costs to review, process and evaluate each transmission project proposal. A refund of $15,000 will be provided to the transmission developer if:

- The transmission developer or its proposal is determined to not satisfy the qualification criteria in Section 13 through 15.1; or
- The transmission developer withdraws its proposal by providing written notification of its intention to do so to the Transmission Provider prior to the First RPSG Meeting and Interactive Training Session for that transmission planning cycle.

15.2 Deadline for Submittal: In order for its transmission project to be considered for RCAP in the current transmission planning cycle, a transmission developer must provide the requisite information identified in Sections 13 through 15.1 to the Transmission Provider in accordance with the contact information provided on the Regional Planning Website no later than 60 calendar days after the SERTP Annual Transmission Planning Summit and Input Assumptions Meeting for the previous transmission planning cycle.

15.3 Initial Review of Qualification Criteria and Opportunity for Cure: The Transmission Provider will notify transmission developers who do not meet the qualification criteria in Section 13 through 15.1, or who provide an incomplete submittal, within 30 calendar days of the submittal deadline to allow the transmission developers an opportunity to remedy any identified deficiency(ies). Transmission developers, so notified, will have 15 calendar days to resubmit the necessary supporting documentation to remedy the identified deficiency.

15.4 Change in the Transmission Developer's Qualification Information or Circumstances: The transmission developer has an obligation to update and report in writing to the Transmission Provider any change to its information that was provided as the basis for its satisfying the requirements of Sections 13 through 15, except that the transmission developer is not expected to update its technical analysis performed for purposes of Section 15.1(6) to reflect updated transmission planning data as the transmission planning cycle(s) progresses. If at any time the Transmission Provider concludes that a transmission developer or a potential transmission project proposed for possible selection in a regional plan for RCAP no longer satisfies such requirements specified in Sections 13 through 15, then the Transmission Provider may remove the transmission developer's potential transmission project(s) from consideration for potential selection in a regional plan for RCAP and/or remove any and all such transmission project(s) from the selected category in a regional plan for RCAP, as applicable.

16. Evaluation of Proposals for Selection in a Regional Transmission Plan for RCAP

16.1 Potential Transmission Projects Seeking RCAP Will be Evaluated in the Normal Course of the Transmission Planning Process: During the course of the then-current transmission expansion planning cycle (and thereby in conjunction with other system enhancements under consideration in the transmission planning process), the Transmission Provider will evaluate current transmission needs and assess alternatives to address current needs including the potential transmission projects proposed for possible selection in a regional plan for RCAP by transmission developers. Such evaluation will be in accordance with, and subject to (among other things), state law pertaining to transmission ownership, siting, and construction. Utilizing coordinated models and assumptions, the Transmission Provider will apply its planning guidelines and criteria to evaluate submittals and determine whether:

1. The proposed transmission project addresses an underlying transmission need(s);
2. The proposed transmission project addresses transmission needs that are currently being addressed with projects in the transmission planning process and if so, which projects could be displaced by the proposed transmission project;[12]
3. Any additional projects would be required to implement the proposed transmission project.

16.2 Transmission Benefit-to-Cost Analysis Based Upon Planning Level Cost Estimates

16.2.1 Based upon the evaluation outlined in Section 16.1, the Transmission Provider will assess whether the proposed transmission project seeking selection in a regional plan for RCAP is considered at that point in time to yield meaningful, net regional benefits. Specifically, the proposed transmission project should yield a regional transmission benefit-to-cost ratio of at least 1.25 and no individual Impacted Utility should incur increased, unmitigated transmission costs.[13]

a. The benefit used in this calculation will be quantified by the transmission costs that the Beneficiaries would avoid due to their transmission projects being displaced by the transmission developer's proposed transmission project.

[12] Entities that are identified to potentially have one or more of their planned transmission projects displaced by the transmission developer's potential transmission project for possible selection in a regional plan for RCAP shall be referred to as "Beneficiaries."

[13] An entity would incur increased, unmitigated transmission costs should it incur more costs than displaced benefits and not be compensated/made whole for those additional costs. For purposes of this Attachment K, the terms "Impacted Utilities" shall mean: i) the Beneficiaries identified for the proposed transmission project and ii) any entity identified in this Section 16.2.1 to potentially have increased costs in order to implement the proposal.

b. The cost used in this calculation will be quantified by the transmission cost of the project proposed for selection in a regional transmission plan for RCAP plus the transmission costs of any additional projects required to implement the proposal.

c. The Transmission Provider will develop planning level cost estimates for use in determining the regional benefit-to-cost ratio. Detailed engineering estimates may be used if available.

16.2.2 For potential transmission projects found to satisfy the foregoing benefit-to-cost analysis, the Transmission Provider and the Impacted Utilities will then consult with the transmission developer of that project to establish a schedule reflecting the expected in-service date of the project for: 1) the transmission developer to provide detailed financial terms for its proposed project that are acceptable to each Beneficiary and 2) the proposed transmission project to receive approval for selection in a regional plan for RCAP from the jurisdictional and/or governance authorities of the Impacted Utilities.

16.3 The Transmission Developer to Provide More Detailed Financial Terms Acceptable to the Beneficiaries and the Performance of a Detailed Transmission Benefit-to-Cost Analysis: By the date specified in the schedule established in Section 16.2.2,[14] the transmission developer shall identify the detailed financial terms for its proposed project, establishing in detail: (a) the total cost to be allocated to the Beneficiaries if the proposal were to be selected in a

[14] The schedule established in accordance with Section 16.2.2 will reflect considerations such as the timing of those transmission needs the regional project may address as well as the lead-times of the regional project, transmission projects that must be implemented in support of the regional project, and projects that may be displaced by the regional project. This schedule may be revised by the Transmission Provider and the Impacted Utilities, in consultation with the transmission developer, as appropriate to address, for example, changes in circumstances and/or underlying assumptions.

regional plan for RCAP, and (b) the components that comprise that cost, such as the costs of:

a. Engineering, procurement, and construction consistent with Good Utility Practice and standards and specifications acceptable to the Transmission Provider,

b. Financing costs, required rates of return, and any and all incentive-based (including performance based) rate treatments,

c. Ongoing operations and maintenance of the proposed transmission project,

d. Provisions for restoration, spare equipment and materials, and emergency repairs, and

e. Any applicable local, state, or federal taxes.

To determine whether the proposed project is considered at that time to remain a more efficient and cost effective alternative, the Transmission Provider will then perform a more detailed 1.25 transmission benefit-to-cost analysis consistent with that performed pursuant to Section 16.2.1. This more detailed transmission analysis will be based upon the detailed financial terms provided by the transmission developer, as may be modified by agreement of the transmission developer and Beneficiary(ies), and any additional, updated, and/or more detailed transmission planning, cost or benefit information/component(s) that are applicable to/available for the proposed transmission project, the projects that would be displaced, and any additional projects required to implement the proposal.[15]

[15]The performance of this updated, detailed benefit-to-cost analysis might identify different Beneficiaries and/or Impacted Utilities than that identified in the initial benefit-to-cost analysis performed in accordance with Section 16.2.1.

16.4 Jurisdictional and/or Governance Authority Approval and Selection for RCAP: The project will be selected for RCAP in the then-current iteration of the regional plan for purposes of Order No. 1000, subject to the provisions of Section 18, if: (i) the detailed financial terms provided in accordance with Section 16.3, as may be modified by agreement of the transmission developer and Beneficiary(ies), are acceptable to each Beneficiary; (ii) the proposed transmission project is found to satisfy the more detailed benefit-to-cost analysis specified in Section 16.3; and (iii) if approval is obtained from all of the jurisdictional and/or governance authorities of the Impacted Utilities by the date specified in the schedule adopted in accordance with Section 16.2.2.[16] If obtaining jurisdictional and/or governance authorities approval requires a modification of the detailed financial terms found acceptable in Section 16.3, and both the transmission developer and the Beneficiary(ies) agree to the modification, then the modified detailed financial terms shall be the basis for the regional cost allocation for purposes of the project.

17. Cost Allocation Methodology Based Upon Avoided Transmission Costs: If a regional transmission project is selected in a regional plan for RCAP in accordance with Section 16.4 and then constructed and placed into service, the Beneficiaries identified in the detailed benefit-to-cost analysis performed in Section 16.3 to potentially have one or

[16] Being selected for RCAP in the then-current iteration of a regional plan only provides how the costs of the transmission project may be allocated in Commission-approved rates should the project be built. Being selected in a regional plan for RCAP provides no rights with regard to siting, construction, or ownership. The transmission developer must obtain all requisite approvals to site and build its transmission project. A transmission project may be removed from the selected category in a regional plan for RCAP in accordance with the provisions of Sections 15.4, 18 and 19.

more of their planned transmission projects displaced by the transmission developer's potential transmission project for RCAP will be allocated the regional transmission project's costs in proportion to their respective displaced transmission costs as found acceptable in accordance with Sections 16.3 and 16.4.

18. On-Going Evaluations of Proposed Projects: In order to ensure that the Transmission Provider can efficiently and cost effectively meet its respective reliability, duty to serve, and cost of service obligations, and to ensure that the proposed transmission project actually proves to be more efficient and cost effective, the Transmission Provider will continue to reevaluate a proposed transmission project, including any such projects that are being considered for potential selection in a regional plan for RCAP and any transmission projects that may have been selected in a regional plan for RCAP. This continued reevaluation will assess then-current transmission needs and determine whether the proposed transmission project continues to be needed and is more efficient and cost effective compared to alternatives as assessed in subsequent expansion planning processes that reflect ongoing changes in actual and forecasted conditions. Even though a proposed project may have been selected in a regional plan for RCAP in an earlier regional plan, if it is determined that the proposed project is no longer needed and/or it is no longer more efficient and cost effective than alternatives, then the Transmission Provider may notify the transmission developer and remove the proposed project from the selected category in a regional plan for RCAP. Reevaluation will occur until it is no longer reasonably feasible to replace the proposed transmission project as a result of the proposed transmission project being in a material stage of construction and/or if it is no longer considered reasonably feasible for an alternative transmission project to be placed in service in time to address the underlying transmission need(s) the proposed project is intended to address.

19. Delay or Abandonment: As part of the Transmission Provider's on-going transmission planning efforts, the Transmission Provider will assess whether alternative transmission solutions may be required in addition to, or in place of, a potential transmission project selected in a regional plan for RCAP due to the delay in its development or abandonment of the project. In this regard, the transmission developer shall promptly notify the Transmission Provider should any material changes or delays be encountered in the development of the potential transmission project. If, due to such delay or abandonment, the Transmission Provider determines that a project selected in a regional plan for RCAP no longer adequately addresses underlying transmission needs and/or no longer remains more efficient and cost effective, then the Transmission Provider may remove the project from being selected in a regional plan for RCAP and proceed with seeking appropriate solution(s). If removed from being selected in a regional plan for RCAP due to delay or abandonment by the transmission developer, then the transmission developer shall be responsible for, at a minimum, any increased costs to the Impacted Utilities due to any such delay or abandonment.

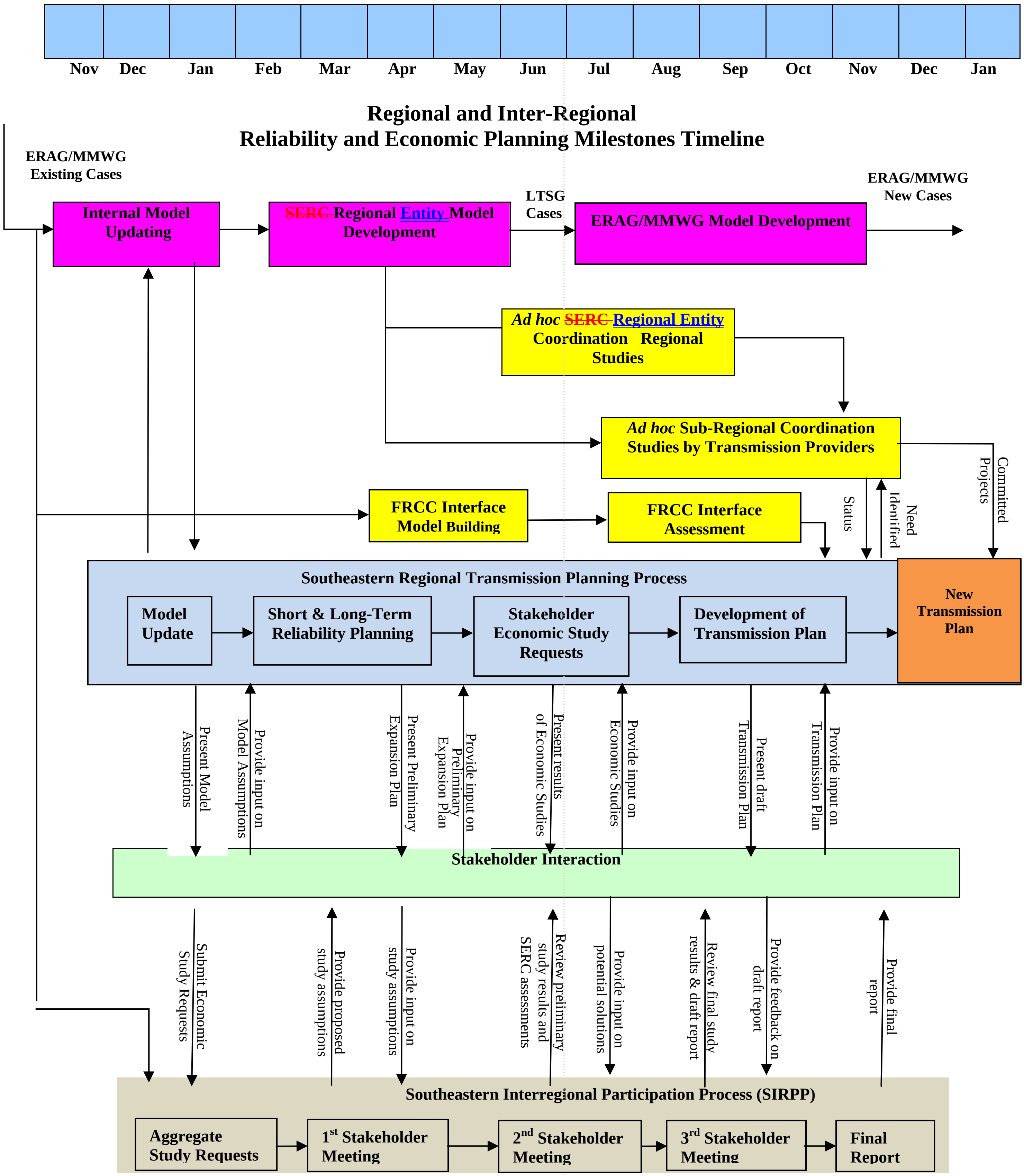
20. Milestones of Required Steps Necessary to Maintain Status as Being Selected for RCAP: Once selected in a regional plan for RCAP, the transmission developer must submit a development schedule to the Transmission Provider and the Impacted Utilities that establishes the milestones, including (to the extent not already accomplished) obtaining all necessary ROWs and requisite environmental, state, and other governmental approvals and executing a mutually-agreed upon contract(s) with the Beneficiaries, by which the necessary steps to develop and construct the transmission project must occur. The schedule and milestones must be satisfactory to the Transmission Provider and the Impacted Utilities. In addition, the Transmission Provider and the Impacted Utilities will also determine the security/collateral arrangements for the proposed project and the deadline(s) by which they must be provided.[17] If such critical steps are not met by the specified milestones and then afterwards maintained, then the Transmission Provider may remove the project from the selected category in a regional plan for RCAP.

21. Mutually Agreed Upon Contract(s) Between the Transmission Developer and the Beneficiaries: The contract(s) referenced in Section 20 will address terms and conditions associated with the development of the proposed transmission project in a regional plan for RCAP, including:

1. The specific financial terms/specific total amounts to be charged by the transmission developer for the regional transmission project to the Beneficiaries, as agreed to by the parties,
2. The contracting Beneficiary's(ies') allocation of the costs of the aforementioned regional facility,
3. Creditworthiness/project security requirements,
4. Operational control of the regional transmission project,
5. Milestone reporting, including schedule of projected expenditures,
6. Engineering, procurement, construction, maintenance, and operation of the proposed regional transmission project,
7. Emergency restoration and repair responsibilities,
8. Reevaluation of the regional transmission project, and
9. Non-performance or abandonment.

[17] Satisfying the minimum, financial criteria specified in Section 13.1.2 alone in order to be eligible propose a project for RCAP will not satisfy this security/collateral requirement.

Exhibit K-3


Nov
Dec
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Jan
Regional and Inter-Regional
Reliability and Economic Planning Milestones Timeline
ERAG/MMWG Existing Cases
Internal Model Updating
~~SERC~~ Regional Entity Model Development
LTSG Cases
ERAG/MMWG Model Development
ERAG/MMWG New Cases
Ad hoc ~~SERC~~ Regional Entity Coordination Regional Studies
Ad hoc Sub-Regional Coordination Studies by Transmission Providers
Committed Projects
Status
Need Identified
FRCC Interface Model Building
FRCC Interface Assessment
Southeastern Regional Transmission Planning Process
Model Update
Short & Long-Term Reliability Planning
Stakeholder Economic Study Requests
Development of Transmission Plan
New Transmission Plan
Present Model Assumptions
Provide input on Model Assumptions
Present Preliminary Expansion Plan
Provide input on Preliminary Expansion Plan
Present results of Economic Studies
Provide input on Economic Studies
Present draft Transmission Plan
Provide input on Transmission Plan
Stakeholder Interaction
Submit Economic Study Requests
Provide proposed study assumptions
Provide input on study assumptions
Review preliminary study results and SERC assessments
Provide input on potential solutions
Review final study results & draft report
Provide feedback on draft report
Provide final report
Southeastern Interregional Participation Process (SIRPP)
Aggregate Study Requests
1st Stakeholder Meeting
2nd Stakeholder Meeting
3rd Stakeholder Meeting
Final Report