UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Regional Transmission Organizations **Docket No. RT01-100-000**

MEDIATION REPORT FOR THE SOUTHEAST RTO

(Issued September 10, 2001)

TO THE COMMISSION:

Pursuant to the Commission's requirements in Order No. 2000,[1] public utilities throughout the country submitted proposals seeking authorization to establish themselves as RTOs. Among those filing proposals were Southwest Power Pool, Inc. ("SPP"), in Docket No. RT01-34-000, in partnership with Entergy Services, Inc. ("Entergy") in Docket No. RT01-75-000; Carolina Power & Light Company ("CPL"), Duke Energy Corporation ("Duke"), and South Carolina Electric & Gas Company ("SCE&G") (collectively, the "GridSouth Companies" or "GridSouth") in Docket No. RT01-74-000; Florida Power & Light Company ("FPL"), Florida Power Corporation ("FPC") and Tampa Electric Company ("TEC"),(collectively, the "GridFlorida Companies" or "GridFlorida") in Docket No. RT01-67-000 and Southern Company Services, Inc. ("Southern"), in Docket No. RT01-77-000 (collectively referred to herein as plan sponsors). In separate orders issued concurrently with the order initiating mediation, the Commission concluded that it was necessary that the federal jurisdictional transmission owners in these dockets combine to form a single Regional Transmission Organization (RTO) in the Southeast (hereinafter referred to as the "Southeast Power Grid" or "SPG").

Believing that the resolution of issues associated with the formation a single Southeastern RTO should be the subject of good faith negotiations among the parties of all relevant proceedings, the Commission initiated mediation for the purpose of

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[1] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Statutes and Regulations, Regulations Preambles July 1996-December 2000 ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Statutes and Regulations, Regulations Preambles July 1996-December 2000 ¶ 31,092 (2000), petitions for review pending sub nom, Public Utility District No. 1 of Snohomish County, Washington v. FERC, Nos. 00-1174, et al. (D.C. Cir.).

facilitating the formation of a single RTO for the Southeastern United States. To aid the parties in this goal, the Commission directed the undersigned Administrative Law Judge and former Chairman Herb Tate, an independent consultant with a high level of familiarity with and knowledge of the electric industry, to convene a meeting and to mediate settlement discussions for a period of 45 days with all of the parties in Docket Nos. RT01-34-000 (SPP), RT01-74-000 (GridSouth), RT01-75-000 (Entergy), and RT-77-000 (Southern). In addition, the parties in Docket No. RT01-67-000 (GridFlorida) were encouraged to participate. Further, the State Commissions, the Tennessee Valley Authority ("TVA"), the South Carolina Public Service Authority ("Santee Cooper"), and the Southeastern Power Administration ("SEPA") were urged to be present and to engage as full participants in the mediation.

The Commission further directed that a report be filed within 10 days after the 45 day period which includes an outline of the proposal to create a single Southeastern RTO, milestones for the completion of intermediate steps, and a deadline for submitting a joint proposal. This Mediation Report is submitted to ensure the timely accomplishment of the Commission's directives and, more specifically, to obtain Commission review of the models for the formation of the single Southeast Power Grid ("SPG") platform which have resulted from this collaborative mediation process to date.

I. BUILDING COALITION MODELS THROUGH MEDIATION

As noted by Commissioner Massey in his concurring opinion with the Order Initiating Mediation, "Each of the regions present their own unique challenges to the mediator. ...In the Southeast, the challenge is to kick start a region that has been sorely lagging the rest of the nation in grid regionalization."

In accordance with the Commission's Order, all parties in the above referenced dockets were directed to participate in the mediation process and were directed to have persons present with authority to act with respect to all matters to be addressed. In addition, the parties in Docket No. RT01-67-000 (GridFlorida), the State Commissions, TVA, Santee Cooper, and SEPA were urged to be present and to engage as full participants in the mediation. Accordingly, approximately 200 participants (hereinafter referred to as "the market participants" or "the full group") were actively engaged in this mediation process. The first meeting, convened on July 17 and 18, 2001, resulted in the establishment of a procedural protocol for the mediation process that would provide a structured environment for the full and active participation of all of the plan sponsors and all of the market participants in a manner consistent with the goal of the formation of a single RTO for the Southeast. In accordance with the procedural schedule adopted by the mediation team and agreed to by the parties, full group meetings were conducted on

Tuesday, Wednesday, and Thursday of the next four weeks (July 24, 25, 26, and 31, August 1, 2, 7, 8, 9, 14, 15, and 16) from 8:30 or 9:00 a.m. until 4:30 or 5:00 p.m. with separate "break out" work groups and smaller group meetings convened on Mondays and Fridays and during breaks on full group work days. The mediation team found these "one-on-one" smaller group meetings to be necessary and appropriate to the full discussion and exploration of issues and concerns of the various and diverse market participants, as well as those of individual plan sponsors.

For purposes of this mediation effort, four basic "models" for the formation of an RTO in the Southeast can be identified from the multiple filings in the above referenced dockets: these are referenced herein as the SPP/Entergy model, the GridSouth model, the GridFlorida model and the SeTran model. Early discussion with the market participants reflected that, while most participants were very familiar with the provisions of the RTO model for the docket in which they had intervened, most participants were not familiar with key aspects of the other three models. To enable the market participants to become familiar with key aspects of all four RTO models represented in the multiple dockets directed for mediation, the plan sponsors were requested to provide presentations to the market participants describing the key aspects of their respective models. To break down the presentations to manageable "clusters" of information, the presentations were divided into segments which roughly tracked the four main characteristics and eight core functions required of an RTO under Order 2000.

The market participants, as well as the plan sponsors, quickly reached consensus that the independence and governance aspects of the RTO models provided the greatest challenge, and the greatest opportunity, for our mediation efforts. As a result, this critical component of each of the four RTO models was addressed first and received the greatest level of attention throughout the mediation process. The SPP/Entergy, GridSouth, GridFlorida, and SeTran plan sponsors each made presentations to the full group of more than 200 market participants describing the key features of their respective RTO models regarding the "core functions" of independence/governance. The market participants, as a group, were then provided a full opportunity for questions and answers with the plan sponsors to enhance their familiarity with each model, then individually "polled" to provide each market participant an opportunity to state their preference for a particular model and why.

All four RTO models were presented to provide the market participants with the widest range of information and choices for discussion and feedback among themselves and with the plan sponsors. Feedback from the market participants took the form of questions to the plan sponsors, informal discussion and dialog, as well as the more formal "preference polling" referenced <u>supra</u> whereby each market participant was provided an opportunity to voice his or her "preference" for a particular RTO model. While participation in the "preference polling" was strictly voluntary, this process was well received and utilized by a majority of the market participants. "Preference polling" results captured by owner classification "sectors" proved to be very helpful to minimize distortions to the polling process while still permitting each market participant to be fully engaged in the collaborative process (particularly with respect to SPP members). Owner classification sectors were identified for polling purposes as follows: IOUs, Cooperatives, Municipals, Federal, IPPs/Generators, Power Marketers, Consumer/Industrials, and in an effort to facilitate their active involvement in the mediation process a separate sector was created for State Commissions.

This process was not "static" but rather was an "iterative" one whereby the plan sponsors were encouraged to ***react*** to the feedback of the market participants by ***evolving*** their respective RTO models to a higher level of development in response to the concerns of the market participants. The market participants were able to respond, individually and by sectors, to those aspects of the models that were favorably received and those aspects of the models which continued to cause concern. This process proved to be a very effective means of providing market participant input to plan sponsors who then used this critical feedback to modify their proposals for the purpose of broadening market participant support for their model in the next polling. Thus, in this novel "market based" approach to mediation, each group of plan sponsors presented, and "marketed" to the full group of over 200 market participants their respective RTO models, stressing those aspects of their model that the plan sponsors believed would meet or exceed the requirements of Order 2000, as well as addressing how key aspects of the model would be expected to meet the business needs of the greatest number of market participants.

The first "preference polling" conducted on July 25th, provided the plan sponsors with important information regarding the strengths and weaknesses of their RTO models as reflected by the concerns and issues of the market participants. Plan sponsors were able to identify those areas in which key aspects of the models were very similar and those areas where the models remained significantly divergent. Further, in addition to this "market based" mediation process, traditional mediation techniques in the form of multiple meetings with the parties in separate break-out rooms also ensured that the plan sponsors continued to strive to meet the directives of the Commission regarding the formation of a single RTO in the Southeast. This multidimensional collaborative process proved remarkably successful in providing an environment for the early coalition of the GridFlorida and GridSouth RTO models. For the reasons discussed more fully herein below, the early coalition of these two models provided a significant strategic advantage to the proponents of these models throughout the mediation. Among other things, the plan sponsors were able to quickly identify the strongest elements of each for the purpose of "converging" to a much stronger model than either would have been standing alone. In particular, the GridFlorida model, clearly reflecting the strength of its development through an extended collaborative process and prior Commission approval, contributed many key elements of the newly formed coalition model which garnished widespread approval and support from market participants and other plan sponsors. Further, by ***reacting*** to market participant feedback and ***evolving*** their individual RTO models to a higher level of development through coalition and convergence, both GridFlorida and GridSouth were able to approach the mediation process with a stronger model and a unified front. Accordingly, the market participants were provided with a joint presentation of the plan sponsors of a much strengthened coalition model to consider in the second "preference polling" conducted on July 31st. The plan sponsors were: GridSouth, comprising of: Carolina Power & Light Company ("CPL"), Duke Energy Corporation ("Duke"), and South Carolina Electric & Gas Company ("SCE&G"); and the plan sponsors for GridFlorida: Florida Power & Light Company (“FPL”), Florida Power Corporation (“FPC”) and Tampa Electric Company (“TEC”), collectively referred to as "the Grids",

Meanwhile, Southern Company, acting as agent for Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company and Savannah Electric and Power Company, and its supporting plan sponsors Georgia Transmission Corporation (“GTC”), MEAG Power, Dalton Utilities, South Mississippi Electric Power Association (“SMEPA”), the City of Tallahassee, Florida (“Tallahassee”), JEA (formerly Jacksonville Electric Authority), South Carolina Public Service Authority (“Santee Cooper”) (collectively referred to as "SeTran"), were also reacting to the feedback of the market participants obtained through the multidimensional collaborative process described supra, and evolving iterations of its RTO model accordingly. Like GridSouth, SeTrans identified many aspects of the other models which were similar to its own for purposes of convergence and adopted several key elements of the GridFlorida model which had received widespread market participant support, such as the "market monitor" component of that model, to create a significantly improved RTO model for presentation to the market participants at the second preference polling.

Regrettably, the strengthening of the models through coalition and convergence which occurred with respect to the Grids and SeTran models did not occur with respect to the SPP/Entergy model. During the course of the mediation process, both within the full group meetings and as a result of separate smaller group meetings with SPP and Entergy, it became clear that the relationship between SPP and Entergy had failed to stabilize to the degree necessary to support a viable model for the Southeast RTO. In point of fact, despite good faith and earnest efforts, SPP failed to stabilize a "partnership" with any of the Southeast plan sponsors. While Entergy continued to be a strong advocate throughout the mediation process of many of the most desirable attributes of the SPP/Entergy model, Entergy actively continued to seek a "host" RTO platform within the Southeast footprint other than SPP. In point of fact, Entergy soon entered into substantive discussions with "the Grids" to explore the possibility of an evolution of that model which would accommodate a consolidation between these plan sponsors. Further, because many of SPP's members are geographically located outside the Southeast RTO footprint described by the Commission in its July 12th Orders, despite its continued efforts to remain actively engaged in this mediation, SPP found it appropriate to enter into discussions to form a region-wide RTO in the Midwest. These developments soon made it clear that the SPP/Entergy alliance had become even more unstable than had been reflected in previous filings with the Commission and that, absent a meaningful alliance with a plan sponsor in the Southeast RTO footprint, the model could not continue to be presented to the market participants as a viable option for the Southeast RTO platform. Accordingly, the SPP/Entergy model was not presented to the market participants for consideration in the second round of "preference polling" conducted on July 31st. Further, for these reasons, it is the recommendation of this Administrative Law Judge that SPP be directed to continue to pursue an RTO coalition in the Midwest.

As a direct result of the feedback from the market participants from this second round of "preference polling", as well as continued discussions between the plan sponsors, the market participants and the mediation team, both the Grids and SeTran made significant and valuable modifications to their respective models. While not resulting in complete consolidation of the two models, important concessions by each of the two groups of plan sponsors and "clustering" of similar or "essentially identical" characteristics of the two models resulted in a further narrowing of the differences between the parties. Further, Entergy's discussions with "the Grids" to explore the possibility of an evolution of that model which would accommodate Entergy's business needs resulted in a coalition of these plan sponsors. Accordingly, for the third and final "preference polling" on independence and governance conducted on August 7th, the market participants were presented with a "**Collaborative Governance Model**" derived in large part from the Grids and Entergy models and an **"Independent System Administrator Model**" derived from the SeTran model, both of which reflected significant and valuable modifications to the initial proposals. Consolidation and convergence of similarities of the two models on key characteristics and core functions, as well as independent evolutions and enhancements of the two models in response to market participant feedback, resulted in a presentation to the full group of market participants on August 7th of vastly improved models from each of the two groups of plan sponsors.

This mediation format proved to be highly effective and may have continued to provide meaningful results in terms of continued evolutions and enhancements of the two models in response to market participant feedback; however, time did not permit additional iterations utilizing the "preference polling" format. Accordingly, new techniques to revitalize the mediation effort were implemented during the remaining two weeks of our collaborative process. The plan sponsors were directed to submit "Straw Man" proposals outlining the key aspects of their respective models with respect to each of the four RTO characteristics and eight core functions required by Order 2000. The market participants were then provided an opportunity to submit written comments to each Straw Man proposal. Recognizing that each market participant had concerns and goals that may have been unique, but recognizing further that many market participants shared many concerns and goals in common, a "Stakeholder" workgroup was created comprised of three representatives from each owner classification sector that had been utilized in the "preference polling".

The owner classification sectors were identified for this purpose as follows: IOUs, Cooperatives, Municipals, Federal, IPPs/Generators, Power Marketers, Consumer/ Industrials, and in an effort to facilitate their active involvement in the mediation process a separate sector was created for State Commissions. The sector representatives were then charged with the responsibility of coordinating with their respective sector members and reporting back to the mediation team as a liaison, as well as preparing "sector summaries" of the individual market participant comments provided in response to the Straw Man proposals. The Stakeholder workgroup proved to be an invaluable resource in facilitating continued communications with the full group of market participants and in ensuring that the market participants were fully represented in continued negotiations with the plan sponsors during the last two weeks of the mediation. As a result, both models continued to evolve in significant and material ways in direct response to this market participant feedback right up to the very last day of the mediation. The plan sponsors were then directed to submit a final iteration of their respective models on August 31st with final written comments due back to the sector representatives for final "sector summaries" to be submitted to the mediation team on September 5, 2001.

II. SUMMARY DESCRIPTIONS OF THE TWO MODELS

The plan sponsors have participated in this mediation in good faith and have used the mediation as an opportunity to further discuss and assess the critical issues associated with the development of a single Southeastern RTO as directed by the Commission. In this regard, the plan sponsors have worked in good faith to understand and accommodate each other’s concerns and goals as well as the concerns and goals of other stakeholders. As a result, it is recognized that this mediation has led to many broad compromises on a wide range of issues in a very short period of time; however, it is also recognized that both models represent a "work in progress" with many issues that remain to be addressed. Further, the plan sponsors wish to specifically note that these issues must be fully discussed with their state regulatory commissions and any necessary state approvals must be obtained.[2] Because of the importance of ensuring that state regulatory commissions of the affected states, many of whom must approve the participation in an RTO by transmission owners subject to their jurisdiction, continue to have the opportunity to have input into the process, I am recommending that regardless of the RTO platform ultimately adopted by the Commission that the Commission continue to encourage and utilize a collaborative process which accommodates both stakeholder and state utility commission input.

While both models are a "work in progress" and require further Commission attention with respect to key aspects of Order 2000 RTO characteristics and core functions, it is the opinion of the undersigned Administrative Law Judge that of the two models the "**Collaborative Governance Model**" is better developed and more clearly in compliance with the requirements of Order 2000 based on a "best practices" analysis of other RTOs which have received Commission approval and prior Commission precedent with respect to the current filings. While the **Collaborative Governance Model** represents a reasonable compromise that attempts to address the sometimes conflicting needs and desires of the market participants and other regional stakeholders, because a complete consensus among the plan sponsors and the more than 200 stakeholders that participated in this mediation effort was not reached, and to ensure that the Commission is provided with the widest range of options possible in evaluating where to go next in ensuring the timely, efficient and effective formation of a single RTO in the Southeast, both the **Collaborative Governance Model** (representing a consolidation and evolution of some of the best aspects of the GridFlorida, GridSouth and Entergy models) and the **Independent Systems Administrator Model** (representing a convergence and evolution of some of the best aspects of the model proposed in Southern's filings) will be presented to the Commission for consideration in this report.

a. The Collaborative Governance Model

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[2]The plan sponsors have cooperated fully in this mediation process but have affirmed that by doing so they have not waived any legal rights or claims with respect to any of the matters addressed herein or the right to assert a contrary position either in the instant mediation or in any other forum.

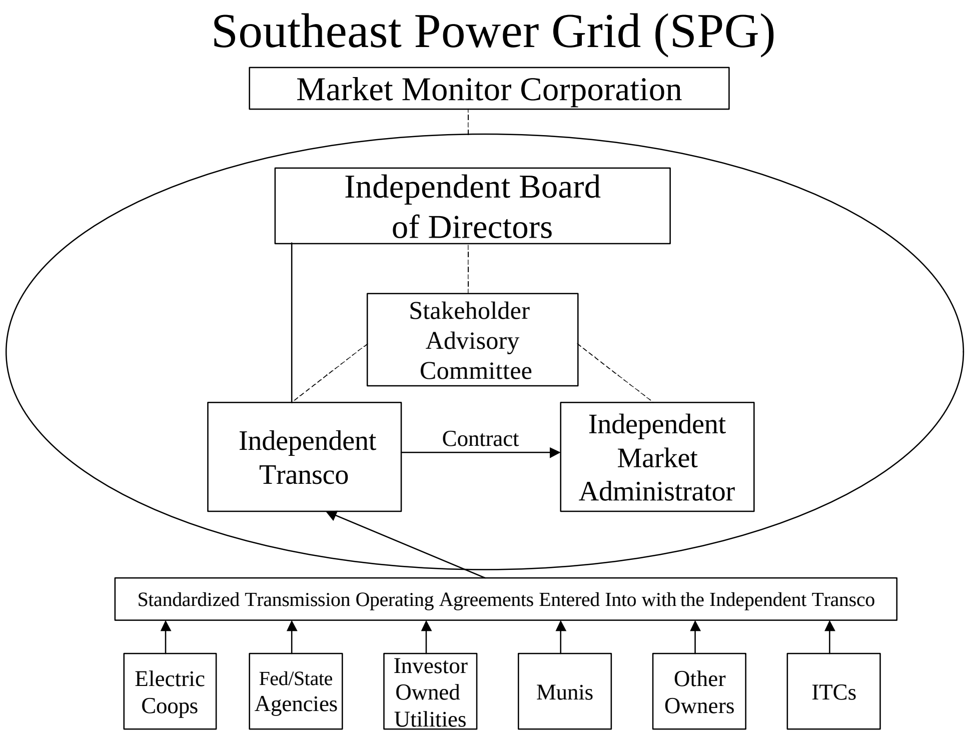
The **Collaborative Governance Model** has the advantage of being able to draw from three well-developed RTO proposals, two of which have been approved in all material respects by the Commission. See GridFlorida LLC, 94 FERC ¶ 61,363 (2001); GridSouth Transco, LLC, 94 FERC ¶ 61,273 (2001). As a result, many of the stakeholders were already familiar with large portions of this coalition model. For example, this model largely adopts the GridFlorida Planning Protocol and Market Monitor proposal that were approved by the Commission. Like the GridSouth and GridFlorida proposals, it calls for the creation of a for-profit transmission company (the "Transco"), with an Independent Board of Directors, to act as the RTO for the SPG RTO. The model also contains elements which are completely new and represent improvements to previous Commission filings proposed in direct response to the concerns and goals of the market participants identified in this collaborative process. The most significant of these calls for the delegation of certain operating responsibilities to an "Independent Market Administrator" ("IMA"), which was not a feature of any of the models as previously filed. In particular, this enhancement to the model, described more fully below, is intended to facilitate public power participation in a Southeastern RTO by placing key functions with the non-profit IMA which many market participants felt should not be filtered through the for-profit Transco arm of the RTO. When these improvements and enhancements are considered in the context of the model as a whole, it is the opinion of the undersigned Administrative Law Judge that the **Collaborative Governance Model** is fully consistent with the independence and governance requirements of Order No. 2000 and provides an appropriate framework that could lead to the establishment of an efficient and effective RTO in the Southeastern United States.

My strongest recommendations in support of the **Collaborative Governance Model** pertain to the independence and governance features of the model. As previously indicated, independence and governance were considered to be the most important aspects of the SPG RTO platform by plan sponsors and market participants alike and therefore were subject to the highest level of attention during the mediation. The independence and governance features of this model are outlined below.

1. Independence And Governance (RTO Characteristic 1)

i. Overview

The governance structure of the **Collaborative Governance Model** is illustrated by the following chart:



As explained in more detail below, an independent Transco with an independent Board of Directors selected by stakeholders will act as the SPG RTO. The Transco will delegate by contract certain RTO functions to an independent Market Administrator ("IMA"). The Transco may initiate a process to reclaim functions from the IMA after five years, or sooner in the event of exigent circumstances. A stakeholder Advisory Committee will be formed to provide advice to the Board, and an independent Market Monitor will exercise oversight over the entire SPG RTO and SPG RTO markets.

Transmission Owners in the region, including public power entities, will have at least three options for participating in the SPG RTO. They may: (1) divest their facilities to the Transco; (2) transfer operational authority over their facilities to the SPG RTO pursuant standardized Transmission Operating Agreements entered into with the Transco; or (3) divest or transfer operational authority over their facilities to an ITC that in turn will enter into a standardized Transmission Operating Agreement with the Transco.

Proponents of the for-profit Transco based model advocate its adoption by the Commission as the platform for the SPG RTO for several reasons:

- A Transco should have a greater access to capital and, because its profits will be at risk, a greater incentive to innovate.

- A Transco model will facilitate voluntary divestiture of transmission by integrated utilities.

- A Transco structure will facilitate expansion of the grid in the region by giving a transmission-owning entity a financial incentive to seek out and develop upgrade opportunities.

- A Transco will be an owner/operator, which has benefits in terms of efficiency and accountability.

- The Transco model vests responsibility for planning of expansions in the entity that has the ultimate responsibility for financing those expansions.

ii. The Transco

The Transco will be a limited liability company that will own the transmission facilities of any transmission owner that wishes to divest its assets to the Transco, as well as new facilities constructed by the Transco in accordance with the Planning Protocol described below. The Transco will be managed by an Independent Board that will be selected by the stakeholders pursuant to the process described below. Although specific commercial terms will have to be developed, the most significant aspects of the Transco are as follows:

a. <u>Transco Ownership of Transmission Assets</u>

Any transmission owner that wishes to divest its transmission facilities may transfer those assets to the Transco.[3] All transmission owners in the SPG region, including public power entities, will have at least two years after the commencement of RTO operations to enter into an agreement to divest their transmission facilities to the Transco. During this period, the Transco will be obligated to acquire transmission facilities in the SPG region at their net book value, subject to the negotiation of commercially reasonable terms with the Independent Board. It is necessary to place some limit on the right to "put" transmission assets to the Transco in order to permit an IPO to

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[3] As explained below, transmission assets also may be transferred to an ITC.

take place after that time and the two year period represents a compromise position to accommodate other stakeholder interests.

A transmission owner may request that it receive membership interests in the Transco in exchange for its assets or it may request that it be paid cash for the transmission assets. The Transco may decline to pay cash under certain circumstances that will be specified in the governance documents such as, for example, when the cash payment would threaten the reliable operation of the SPG RTO system or would threaten any subsequent IPO by the Transco.

After the initial "put" period, the Transco still will be able to acquire transmission assets from transmission owners that wish to divest. However, there is no obligation placed on the Transco to make such a purchase, and no specification as to the price that must be paid for such assets or the form of consideration that must be paid. Instead, the terms of the transfer would have to be negotiated between the Transco and the transmission owner.

b. Board Selection Process

The process for selecting the Independent Board of Directors is based largely on the GridFlorida Board selection process that was approved by the Commission. See GridFlorida LLC, 94 FERC ¶ 61,020 (2001). This process calls for a Board Selection Committee to be established to select the initial Directors. The Committee will consist of up to 3 representatives from the entities that have made a legally binding commitment to divest their facilities to the Transco, and one representative from each of the following stakeholder groups: (i) investor-owned utilities that are owners of transmission facilities in the markets served by SPG that have not made a divestiture commitment, (ii) electric utilities that distribute electricity at retail in the markets served by SPG, (iii) non-investor-owned utilities that sell electricity exclusively at wholesale in the markets served by SPG, (iv) entities that own or are developing generation facilities within the geographic region under management of SPG, (v) power marketers and brokers, and (vi) end users or governmental or non-profit organizations that are not utilities, that represent end-use consumers’ economic or environmental interests and are located within the geographic region in which SPG provides transmission services.

Each of the stakeholder groups will determine the method for selecting its representative on the Board Selection Committee. No single entity (including affiliates and other entities with which there is a pending merger) will have more than one representative. The Board Selection Committee thus will represent a balanced mix of interested stakeholders.

The Committee will select one of three specified nationally recognized executive search firms to propose a pool of 12 candidates for election as initial Directors. The search firm will be retained only after stakeholders have had an opportunity to join a particular stakeholder group and thus to participate in the Committee. Each candidate must have qualifications equivalent to those of directors of public corporations with equivalent or larger revenues and assets than those anticipated for the Transco, and at least nine of the candidates must be or have been a president, chief executive officer ("CEO"), chief operating officer ("COO") or director of a publicly traded company. One of the candidates also must have experience working with public power entities.

The Board Selection Committee will, upon a majority vote of such Committee, select eight candidates from the pool of twelve proposed by the search firm as its slate of candidates for election as initial Directors. Following their selection, such candidates will meet to select, in consultation with the Board Selection Committee, the initial CEO, who also will be the Chairman of the Board and the ninth Board member. The CEO need not have been one of the candidates presented by the Board Selection Committee. This process clearly ensures that no Market Participant or class of Market Participants will have control over the selection of the initial Board.

It is expected that, ultimately, there will be an IPO or a private placement of voting shares and that shareholders will select subsequent members of the Board. However, until such time that there is an IPO or a private placement of voting shares, any successor Board candidate proposed by the Board must be approved by the stakeholder Advisory Committee.

c. Advisory Committee

An Advisory Committee consisting of a broad array of stakeholders will be established to advise the Board. This model largely adopts the GridFlorida Advisory Committee proposal, which was approved by the Commission. See GridFlorida LLC, 94 FERC ¶ 61,363 at 62,327-28. A designated representative of the Advisory Committee will be entitled to: (i) make presentations to the Board at regularly scheduled Board meetings on matters that a majority of the representatives of the Advisory Committee agree are of sufficient importance to merit Board attention; (ii) prepare and submit written recommendations and reports, at any time, to the Board and senior management of the Transco; (iii) meet and confer with senior management of the Transco, at least once during each calendar quarter, on matters of concern or interest to the Advisory Committee; and (iv) have reasonable and timely access to information concerning the Transco's operation of SPG's assets, in a manner consistent with the SPG Information Policy. If there is additional information desired by the Advisory Committee from the

Board, the Advisory Committee can request that the Market Monitor attempt to obtain the information. Furthermore, when the vote of the Advisory Committee is not unanimous, minority positions also may be presented to the Board. Thus there are significant opportunities for the Advisory Committee to obtain information regarding SPG RTO operations and for the representatives to convey any concerns they have to the Board.

The Advisory Committee will consist of up to 13 representatives (or less if each seat on the Advisory Committee is not filled). Each of the following stakeholder groups will be entitled to appoint up to that number of representatives set forth below (provided, however, that no single entity, including its affiliates and entities with which a merger is pending, will be entitled to appoint more than one representative to the Advisory Committee):

- Three representatives of investor-owned utilities that are, or as of October 16, 2000 were, owners of transmission facilities in the markets served by SPG.

- Two representatives of electric utilities that distribute electricity at retail in the markets served by SPG.

- Two representatives of non-investor-owned utilities that sell electricity exclusively at wholesale in the markets served by SPG.

- Two representatives of entities that own or are developing generation facilities that will take transmission service from facilities owned or controlled by SPG.

- Two representatives of power marketers and brokers.

- Two representatives of end-users or governmental or non-profit organizations that are not utilities, represent end-use consumers' economic or environmental interests, and are located within the geographic region in which SPG provides transmission service. One representative shall be of an end-user and one shall be of a governmental or non-profit organization.

It is up to each stakeholder group to determine who its representatives will be and how representatives will be replaced and successors chosen. In light of this structure, no one participant or class of participants will dominate the Advisory Committee.

d. Other Independence Safeguards

This model also adopts other safeguards of RTO Independence that were included in the GridFlorida proposal and accepted by the Commission. These include: (1) restrictions on ownership of securities of market participants by the Transco, and its Directors, officers and employees (and their dependent family members); (2) a Code of Conduct applicable to the Directors, officers and employees of the Transco; (3) restrictions on movement by employees between the Transco and Market Participants; (4) adoption of an Information Policy that makes information available to stakeholders; and (5) Independence compliance auditing as required by Order No. 2000. See GridFlorida, 94 FERC ¶ 61,020 at 61,047-49; GridFlorida, 94 FERC ¶ 61,363.

iii. INDEPENDENT MARKET ADMINISTRATOR

a. Initial Functions

While the Commission has already ruled in Order No. 2000 in general and in the GridFlorida and GridSouth proceedings in particular that Transcos do not violate the Commission's Independence criteria[4], other stakeholders, and in particular public power stakeholders, continue to voice concerns of "institutional bias", i.e., that a Transco might not be sufficiently independent, given its ownership of transmission facilities, to make unbiased decisions on issues impacting other stakeholder participants in the RTO. In direct response to these concerns as identified and discussed in this collaborative process, the proponents of this model developed and incorporated an entirely new feature, which was not a feature of any of the models as previously filed, providing for the delegation of certain operating responsibilities to an "Independent Market Administrator" ("IMA") on an interim basis. The IMA and its directors, officers and employees would be independent from any Market Participant, and would be subject to the same restrictions on ownership interests in Market Participants and Code of Conduct that are applicable to the Transco. The IMA would be selected by stakeholders as described below, and will execute a five-year contract with the Transco.

Initially, the IMA would be assigned five principal functions: (1) Administration of all markets administered by SPG; (2) Exercise of operational authority over the SPG system; (3) Administration of the SPG OASIS and calculation of TTCs and ATCs; (4)

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[4]GridFlorida, 94 FERC ¶ 61,363 at 62,329; GridSouth, 94 FERC at 61,985-86. See also Southwest Power Pool, Inc., 94 FERC ¶ 61,359 at 62,293-94 (finding Entergy ITC to be independent).

Receiving and processing requests for transmission service and interconnection (except for performance of system impact and other studies); and (5) Assumption of the Security Coordinator function. The way in which these functions will be performed is described in more detail below in the discussion of the various RTO Minimum Characteristics and Functions.

The Transco will retain all RTO functions not assigned to the IMA. These functions include: (1) rate design; (2) transmission planning; (3) performance of system impact and other studies for transmission and interconnection service requests; and (4) market design.[5] Again, the way in which these functions will be performed is described below.

This recommended split of RTO functions between the Transco and the IMA was the subject of extended discussions during the mediation. The split represents my best judgment of what is necessary both to establish a financially strong Transco that will have significant facilities divested to it and to allay the perception of potential bias in RTO operations. I strongly recommend that this split of functions not be revisited.

b. <u>Selection of IMA and Negotiation of the IMA Contract</u>

The process for selecting the IMA is intended to balance the need for the transmission owners to be assured that a qualified entity assumes the critical functions of operating their transmission systems with the desire of the other stakeholders to ensure that a truly independent and qualified entity is selected. A form of contract will be developed through a collaborative process and filed with the Commission along with the other governance documents. The form contract will be used to solicit interest in the position. The transmission owners will then establish a list of at least five qualified entities that are willing to take on the role of the IMA. This list will be presented to the stakeholder Advisory Committee, which will then select the entity that will act as the IMA.

Once selected, the IMA will negotiate its contract with the Independent Board of the Transco, and the Board will be free to negotiate changes in the form contract. The executed contract will have a five-year term and at a minimum will include the provisions

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[5]Nevertheless, once the initial market structure has been approved by the Commission, the Transco must obtain the input of the Advisory Committee, affected state utility commissions and the IMA prior to making any filing with the Commission to modify that market structure.

that are described in this Report. Finally, the contract will include the IMA's initial budget for performing its tasks. This budget may be changed only upon the approval of both the Transco Board and the Advisory Committee. The contract also will permit the Board to remove the IMA prior to the end of the five-year term, upon the concurrence of the Advisory Committee, for inadequate performance or other exigent circumstances.

c. Reassignment of Functions and Replacement of IMA

Future experience of other RTOs that do not have the same splitting of functions may reveal that the concerns regarding Transcos in fact have no basis. Therefore, the recommended SPG RTO includes a process to permit the Transco at some point in the future to assume one or more of the functions that initially have been assigned to the IMA, if experience shows that it would be more appropriate for the Transco to perform the function. This process is intended to provide stakeholder and regulatory review of any proposed reassignment of functions.

If, at the end of the five-year term, the Transco wants to undertake functions initially assigned to the IMA, it must provide one year's notice to all stakeholders, the IMA and the Market Monitor. A collaborative process will be initiated within 30 days of this notice in which stakeholders can provide input to the Transco's proposal. No later than 60 days after the initiation of the collaborative process, the Market Monitor must issue its recommendation as to whether the Transco should be able to assume the IMA functions as proposed, or the Transco will be free to file for approval of the proposed changes.

Any changes proposed by the Transco will be required to be filed under either Section 203 and/or 205 of the Federal Power Act, depending upon the nature of the change. If the Market Monitor recommends against the proposed change, the Transco will enter into informal negotiations with the Market Monitor and any interested stakeholder. The Transco may not file the proposed change at the Commission any sooner than 90 days after the date of the Market Monitor's recommendation, unless the Market Monitor reaches agreement with the Transco prior to that time. The proposed transfer of functions may not take place until the Commission grants all necessary approvals.

If the Transco has not issued one year's notice of its intent to assume some or all of the IMA's functions upon the conclusion of the five-year term, then the Transco must either renew the agreement with the IMA or select a new IMA and enter into an agreement with the new entity calling for that entity to perform the same functions. Any new entity chosen by the Transco to perform the IMA function must be approved by the Advisory Committee.

The IMA's costs will all be paid by the Transco, and ultimately will be recovered by the Transco through the Grid Management Charge. Therefore, the office space, equipment and software used by the IMA will all belong to the Transco. If the IMA is replaced, its contract terminated, or a function assumed by the Transco, the Transco will take possession of these assets so that it will be able to continue operations without incurring a large expense to replace them.

iv. INDEPENDENT TRANSMISSION COMPANIES

The Commission has approved for other RTOs the formation of "Independent Transmission Companies" ("ITCs") that satisfy the Order No. 2000 Independence criteria, but which transfer operational control of their facilities to an RTO.[6] A similar ITC proposal was included in the SPP/Entergy RTO proposal. In that proceeding, the proposed ITC was determined to satisfy the independence and governance requirements of Order No. 2000; however, the Commission did not address the proposed division of responsibilities between the ITC and the SPP.

The **Collaborative Governance Model** is drafted to provide for the delegation of functions to ITCs in a manner that will provide utilities desiring to divest their transmission facilities another meaningful commercial alternative to divesting to the Transco. While the Commission has concluded that because an ITC is independent from all Market Participants, it can assume certain functions that a non-independent transmission owner could not;[7] at the same time, it is important to recognize that the RTO has overall control of the SPG system and has the responsibility for ensuring efficient, reliable operations. The **Collaborative Governance Model** permits the delegation to the ITC of a measure of additional autonomy while recognizing the overall authority and responsibility of the RTO and avoiding the balkanization of regional markets. Further, proponents of this model emphasize that the ITC feature is not limited to private, for-profit companies. Public power entities may also form non-profit ITCs, and public power entities (or any transmission owner) may either divest their transmission facilities to the ITC or transfer operational authority pursuant to transmission operating agreements.

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[6]See Avista Corp., 96 FERC ¶ 61,052 (2001); Bangor Hydro Electric Co., 96 FERC ¶ 61,063 (2001).

[7]Id.

Public power entities therefore are entitled to the same ITC rights as jurisdictional transmission owners.

There are three areas in the mediation where the role of an ITC has been discussed: (1) planning; (2) operations; and (3) rates. The **Collaborative Governance Model** addresses the ITC's role in these areas as follows. Except as provided below and in the attached protocols, the ITC will be treated identically to all other participating transmission owners ("POs").[8]

a. Planning

The control that will be delegated to the ITC with respect to the planning function is limited. Under the **Collaborative Governance Model**, all planning decisions made by the ITC, including those involving Local Area Planning, will be subject to the review and approval of the Transco in accordance with the Planning Protocol.

The business proposition of an ITC is to maintain and expand the grid to serve its customers. The vehicle for accomplishing this purpose is the planning and expansion process. Delegating to the ITC the planning function for its footprint also has the advantage of retaining sub-regional focus on planning at a level that is closer to the users of their transmission system. Because the ITC will be independent of all market participants and subject to the Transco's overall authority, there is no reason to believe that the ITC would favor one market participant over the other in the decisions that it makes, or would even have the ability to do so.

There are three areas where the ITC has been delegated the authority in the first instance to perform planning, subject to the Transco's review and approval. Each of these areas is spelled out in the Planning Protocol attached to this Report.

Local Area Planning

The first area is Local Area Planning, which is the planning for the facilities that are within the ITC footprint necessary to satisfy the needs of Load Serving Entities served by the ITC's transmission system. Such planning would also include the identification of candidate projects to reduce or eliminate congestion within the ITC footprint. As is the case with all Local Area Planning, the results of the ITC's Local Area Planning would be

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[8] In addition, an ITC will always be free to request that the Transco delegate additional responsibilities, subject to any necessary regulatory approvals.

subject to Transco approval and would then be used in the Regional planning process performed by the Transco.

System Impact Studies

The second area is in performing the system impact studies for ITC facilities that are necessary to evaluate requests for firm transmission service. A request for service is submitted to IMA and forwarded to the Transco. In the event that a system impact study that affects facilities of the ITC is necessary, the Transco then delegates the performance of that impact study to the ITC. The study must be performed by the ITC in accordance with the processes and procedures established by the Transco and contained in the SPG RTO OATT and the Planning Protocol applicable to the performance of system impact studies for the entire RTO. The results of the impact study will be provided to the Transco for its approval and use in evaluating the transmission requests and in developing its expansion plans.

Moreover, to ensure one-stop shopping and a single study principle, where the request also impacts facilities not owned by the ITC, the Transco will coordinate the performance of the study with the ITC and the owner of the non-ITC facilities. The time frame for completing this study will be the same regardless of whether the ITC performs the study or coordination between the ITC and the Transco is required. This will ensure that there are no seams issues resulting from giving the ITC a role in the performance of the planning function and that requests for service are addressed timely through one rather than two or more separate studies.

Interconnection Studies

The third area where the ITC is given a planning role is in performing interconnection studies. As is the case with transmission service requests, requests for interconnection to the transmission system of the RTO will be submitted to the IMA and forwarded to Transco. The Transco will then delegate to the ITC the responsibility to evaluate any requests to interconnect to ITC transmission facilities. The ITC will perform the study in compliance with the generation interconnection procedures that have been established by the Transco and approved by the Commission and that will apply to the entire RTO. This delegation is consistent with Commission precedent.[9] Once the study is complete, the results are provided to the Transco for its review and approval. Again, in order to satisfy the one-stop shopping principle established in Order No. 2000,

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[9] See Avista, supra; Bangor Hydro, supra

a single joint study will be performed by the ITC and the Transco for requests that impact facilities located outside of the ITC's system, and will be completed in the same time frame as that set forth in the SPG RTO generation interconnection procedures.

Some stakeholders have expressed concerns that the division of responsibilities between the Transco, IMA, and ITC will be cumbersome and confusing, creating "balkanization" of critical RTO functions. Proponents of this plan disagree, pointing out that the planning authority vested in the ITC is no greater than that vested in all POs during the initial three-year period. That authority would simply be extended for ITCs due to their independence. And the proposal ensures one stop shopping for all studies. Moreover, the policy of permitting ITCs provides another route to divestiture and thus facilitates the best structure for ensuring an independent and well-financed RTO.

b. Operations

The ITC will not be delegated any greater operating authority than other transmission owners that serve as control area operators. Instead, the ITC will be subject to the same provisions that are applicable to all Control Area Operators under the proposed Operating Protocol.

c. Rates

The Commission has recognized that ITCs should be permitted to propose incentive rates that would apply to the revenue requirement that is included in an RTO's rates and to unilaterally make section 205 filings with the Commission to incorporate incentives and performance-based rates as part of its revenue requirement.[10] This model does not include any specific ITC incentive rate proposal; however, the proponents of this model recommend that the right of an ITC, as well as other POs, to file for incentive rates be specifically spelled out in the SPG RTO documentation. However, like other POs, the ITC will not have authority to change the rates or rate-design charged by the RTO, including for transmission service over the ITC's facilities.

2. Scope And Regional Configuration (RTO Characteristic 2)

Order No. 2000 requires the RTO to be of sufficient scope and configuration to permit the RTO to maintain reliability, effectively perform its required functions, and support efficient and non-discriminatory power markets. See Order No. 2000 at 31,079.

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[10] See Avista, supra

This model envisions an RTO that comprises the entire Southeast region, as contemplated by the Commission in its July 12 Order mandating this mediation. Such an RTO would be larger than any RTO that has been formed or proposed to date. Participation by all eligible transmission owners (excepting members of the Southwest Power Pool who have the option to join a Midwestern RTO), in the SPG RTO would include transmission facilities in ten states: North Carolina, South Carolina, Georgia, Florida, Alabama, Tennessee, Mississippi, Arkansas, Louisiana, and Texas.

Another important factor in evaluating the scope and configuration of an RTO is whether the RTO includes all transmission facilities in the region. This model, as modified in this mediation process, has successfully attracted support from all of the investor owned utilities in the Southeast RTO footprint, except Southern, and a wide range of support from market participants, including some supporters from public power. Indeed, public power entities in peninsular Florida did not consider GridFlorida's status as a transmission-owning RTO to prevent public power entities from joining GridFlorida. Moreover, a public power entity has also agreed to turn operational control of its facilities to the transmission-owning ITC being formed by Entergy, who is now also a sponsor of this coalition model. However, as discussed more fully herein below, Southern Company and its affiliates and important members of the public power sector continue to favor the Independent System Administrator model.

3. OPERATIONAL AUTHORITY (RTO CHARACTERISTIC 3)

Order No. 2000 requires that an RTO have "operational authority" over all transmission facilities under its control, and that it act as the Security Coordinator for its region. See id. at 31,090. Under this model, the IMA - pursuant to authority contractually delegated by the Transco - would act as the Security Coordinator for the entire region and would have operational authority over all of the RTO's transmission facilities in accordance with Order No. 2000. That is, the IMA would be responsible for directing the operations of the transmission system, monitoring real and reactive power flows and voltage levels, and scheduling and directing the operation of reactive resources. The control area operators (including the Participating Owners, the Transco and the ITCs) would continue to physically operate the system (e.g., physically switch transmission elements into and out of operation, remove equipment from service, adjust capacitors and reactors, etc.), but they would do so pursuant to operating procedures approved by the IMA and subject to the direction of the IMA. The control area operators would continue to be responsible for the safety of their systems.

With respect to control areas, this model provides that Participating Owners and ITCs may continue to operate their existing control areas. However, control area consolidation may occur as the RTO matures. The Transco may operate the control areas of the transmission systems that have been divested to the Transco and those over which control has been transferred to the Transco. The Transco would have the option to collapse the control areas over which it has acquired control area operator authority into one or more control areas.

The **Collaborative Governance Model** Operating Protocol Summary ("Operating Protocol"), which is attached hereto as Attachment 1, sets forth an overview of the operating protocols for the SPG RTO and the roles and responsibilities of the IMA and the control area operators within the SPG RTO. The Operating Protocol provides a starting point for the development of operating rules for the SPG RTO.[11] The Operating Protocol provides that the IMA would be responsible for the security of the system as a whole and for ensuring that all control area operators within the RTO have operating procedures in place that meet the security requirements of the SPG RTO. The Operating Protocol further provides that the control area operators would be responsible for operating their transmission facilities in accordance with the operating procedures and subject to directions from the IMA as described in the Operating Protocol.

Finally, in compliance with Order No. 2000,[12] the Transco would prepare and file with the Commission a public report that assesses whether any division of operational authority hinders the SPG RTO in providing reliable, non-discriminatory and efficiently-priced transmission service. This report would include an assessment of the division of responsibility between the Transco and the IMA.

[11]As noted above, the protocols submitted herewith were not the subject of significant discussion during the mediation process. Therefore, while they provide a useful starting point, my inclusion of the protocols with this Report is not intended to preclude the adoption of different provisions in any final protocol submitted with an RTO proposal.

[12]See 18 C.F.R. § 35.34(j)(3)(i) (2001).

4. SHORT-TERM RELIABILITY (RTO CHARACTERISTIC 4)

Order No. 2000 provides that an RTO must have the authority to do the following in order to be able to ensure the short-term reliability of the transmission facilities that it controls: (1) Interchange Scheduling; (2) Redispatch Authority; (3) Transmission Maintenance Approval; and (4) Inform the Commission if local reliability council reliability standards will prevent the RTO from meeting its obligations. See id. at 31,104-05.

Under the **Collaborative Governance Model**, the IMA – through a contractual delegation of authority from the Transco – would be responsible for the short-term reliability of the SPG RTO's transmission facilities and would (1) have the authority for receiving, confirming and implementing all interchange schedules; (2) have the right to order redispatch of any generator connected to its transmission system if necessary for the reliable operation of its facilities; (3) have the authority to approve and disapprove all requests for scheduled outages of transmission facilities; and (4) report to the Commission if it operates under reliability standards established by another entity that hinder its ability to provide reliable, non-discriminatory and efficiently priced transmission service.

Consistent with Order No. 2000, the SPG RTO would not be required to approve generator outages. However, the IMA would be responsible for coordinating generator outage schedules, subject to appropriate confidentiality protections.

In addition, the transmission owners would be responsible for establishing the ratings for their transmission facilities. However, the Transco would have the authority to review those ratings. If the Transco disputes a rating, the Transco may bring the dispute before the SPG RTO's dispute resolution process, provided that the established rating shall be in force pending the dispute resolution process.

The Operating Protocol, attached as Attachment 1 hereto, provides a summary of the operating procedures under which the IMA will maintain the short term reliability of the RTO's transmission system. The Operating Protocol further describes the roles and responsibilities of the IMA and control area operators with respect to dispatching generation. The IMA will, in the context of the real-time balancing market, identify the necessary dispatch instructions and the control area operators will implement these instructions.

5. TARIFF ADMINISTRATION AND DESIGN (RTO FUNCTION 1)

iv. Tariff Administration

In reviewing RTO proposals for compliance with the Tariff Administration function, the Commission reviews whether the RTO has the sole authority to provide transmission service and to make changes to its tariff and to the rates charged for transmission service. This model clearly assigns the necessary authority to the RTO. The authority assigned to the RTO in turn has been allocated between the Transco and the IMA.

The Transco will have primary responsibility for tariff administration, including the exclusive authority to file tariff and rate changes. However, the IMA will play a critical role in the actual provision of transmission service. It will process and make all decisions regarding requests for transmission service and requests for interconnections.[13] The IMA also will have responsibility for scheduling transmission service that has been approved by the Transco, and will have the responsibility in real time to administer the balancing and ancillary service dispatch functions that ensure that scheduled transmission service actually is provided. These responsibilities are described in more detail in the discussion of the Operating Protocol above.

v. Rate Proposal

The **Collaborative Governance Model** Pricing Protocol Summary ("Pricing Protocol"), which is attached hereto as Attachment 2, sets forth an overview of the pricing protocols for the SPG RTO. The Pricing Protocol provides a starting point for the development of a pricing structure for the SPG RTO.[14] The proponents of this model reiterate that the Pricing Protocol reflects a balanced approach to a number of difficult,

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[13]As described elsewhere, the Transco is responsible for performing all necessary system impact and other studies or causing such studies to be performed.

[14]As noted above, the protocols submitted herewith were not the subject of significant discussions during the mediation process. Therefore, while they provide a useful starting point, my inclusion of the protocols with this Report is not intended to preclude the adoption of different provisions in any final protocol submitted with an RTO proposal.

and often conflicting, goals; it is a comprehensive, integrated package that reflects a delicate balance of competing interests.

One of the most significant aspects of the Pricing Protocol is that, while it fully satisfies the Commission's goals and requirements expressed in Order No. 2000, it was specifically designed to limit cost shifting. This aspect of the Protocol is significant because cost shifting has been an important concern of state commissions, as well as one of the major issues associated with establishing independent system operators and RTOs to date. See, e.g., Order No. 2000, FERC Stats & Regs. ¶ 31,089 at 31,176 ("Each ISO approved by the Commission has struggled with the problem of cost shifting among the various individual transmission owners that make up the ISO."); Midwest Indep. Transmission Sys. Operator, Inc., 84 FERC ¶ 61,230 at 62,151 (1998) (Commission recognizing that cost shifting and cost recovery mechanisms are of "paramount concern" to transmission owners).

Another significant aspect of the Pricing Protocol is that its major aspects are based on the pricing structure included in the GridFlorida compliance filing. That pricing structure was one of the areas that received the most attention in comments filed in the GridFlorida proceeding. Thus, it has been adequately vetted before the Commission. After reviewing the comments and responses addressing the GridFlorida pricing plan, the Commission approved all aspects of that pricing structure. Accordingly, the Commission has already approved the major elements included in the Pricing Protocol for this model. While some changes were made to adapt the pricing structure to a larger region, such as including a Southeastern-wide pricing component in addition to zonal and regional components, the basic structure approved by the Commission for GridFlorida has been retained.

(1) Pricing Policies Attained by the Pricing Protocol

The Pricing Protocol was designed to meet a number of important goals as have been described in this Section of the Report. The application of the goals under the Pricing Protocol is described below in the detailed description of the Protocol.

First, all load will be served under the tariff, whether taken directly by the load customer or by an entity on behalf of the load customer. For example, public utilities will take service on behalf of retail load and existing transmission agreements that were entered into prior to the transition to a Southeast RTO ("ETAs"). An alternative approach is to provide that the RTO will provide only unbundled transmission service. However, the broad consensus of the stakeholders participating in this mediation was that service under the RTO OATT should not be so limited.[15] Comparability has been one of the hallmarks of the Commission's open-access policies since it issued Order No. 888. This Pricing Protocol will promote comparability by requiring that all load be served under the tariff.

Second, this model attempts to encourage public power participation through protocols designed to account for legal limitations, such as tax-related matters, and to offer payment for facilities that today are borne solely by public power customers. By encouraging public power participation, this protocol will help eliminate "holes" in the RTO grid that can occur when transmission owners choose not to participate in the RTO. The pricing structure seeks to do so in a manner that balances the desire for public power participation with the need to ensure against significant cost shifts that could occur from immediate roll-in of facilities' costs. The proponents of this model feel that, in many respects, the Pricing Protocol goes beyond what is required to promote public power participation, and reflects significant concessions on the part of investor-owned utilities.

Third, all service under the RTO OATT will be provided under a rate structure designed to eliminate the effects of pancaked rates. The Commission clearly has recognized the benefits of eliminating multiple transmission charges. See, e.g., Order No. 2000, FERC Stats & Regs. ¶ 31,089 at 31,174-75 ("duplication [in transmission charges] can severely restrict the area in which generation can economically be secured. . . . A wider area served by a single rate means more generation is economically available to any customer which means greater competition for energy.").

Additionally, the Pricing Protocol will encourage participation of all transmission owners by adopting protocols that will mitigate the cost shifts associated with the transition to a Southeastern RTO. As discussed above, the Commission has recognized that cost-shifting raises serious issues, and must be addressed. Otherwise, participation in the RTO will be limited.

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[15] In this regard, certain participants have appeals pending related to the Commission's requirement that they purchase transmission service under the RTO OATT to serve their bundled retail native load customers and unconverted ETAs. Those participants have not waived any of their appellate rights. Regardless of the outcome of the appeals, however, under this model all load will be subject to the terms and conditions of the OATT. Also, charges to other load for transmission service will not be impacted by the treatment of bundled retail load and unconverted ETAs in this regard.

Finally, this model will encourage RTO participation by honoring ETAs. Individual OATT transmission service agreements in effect at the commencement of RTO operations will be converted to service under the RTO OATT. If an ETA is not converted, the transmission provider under the ETA will be required to procure services under the RTO OATT necessary to perform under that ETA.

(1) Detailed Description of Pricing Protocol

(a) Facilities Under the Control of the RTO

For pricing purposes, the RTO will consist of four Regions-- comprised of the current footprints for Entergy, SeTrans, GridSouth and GridFlorida. Each Region may adopt methodologies for determining the facilities that are under the control of the RTO and included in rates. These standards will be developed initially with stakeholder input, using, as appropriate, approvals obtained or regional agreements reached during the initial Order No. 2000 compliance process.[16]

It should be noted that the Regions established for pricing purposes do not necessarily affect the SPG RTO for other purposes, such as pricing of energy in the energy balancing market.

(b) Participant Funded, Direct Assigned, and Merchant Transmission

Under the **Collaborative Governance Model**, there may be facilities constructed within the RTO footprint (i) that are directly funded by a participant in return for the associated long-term transmission rights (in the Entergy/SPP RTO proposal filed with the Commission, such facilities are referred to as "participant funded" facilities), (ii) that do not fall within the category of "participant funded" as that term is used in the Entergy/SPP RTO proposal, but the costs of which otherwise are directly assigned (in some proposals, such as GridFlorida, direct assignment was permitted for facilities built ahead of schedule or to accommodate requests for enhanced service above the standard provided in the GridFlorida planning protocol), or (iii) that are merchant funded (in some parts of the country, the Commission has permitted construction of merchant transmission facilities). In each of these cases, the costs of such facilities would not be included in the Zonal, Regional, System, or Grid Management charges discussed below. While the

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[16] However, in Florida the results of the stakeholder process already conducted will be used, i.e., all transmission facilities 69 kV and above will be under the control of the RTO and included in rates. This approach was approved by the Commission.

details of the treatment of these types of facilities should be the subject of further discussions, the facilities will be subject to the control of the IMA and Transco for planning and operations purposes to the same extent other similar facilities are subject to such control.

(c) Rates for Load Within the RTO

Charges for transmission service to load within the RTO will consist of (i) a Zonal Charge (to recover the cost of Existing Facilities), (ii) a Regional Charge (to recover the cost of new Non-Bulk Transmission Facilities[17] other than those described above), (iii) a System Charge (to recover the cost of new Bulk Transmission Facilities other than those described above), and (iv) a Grid Management Charge. These charges will be designed using consistent allocation methods to ensure that there is no double recovery of costs within two or more charges.

(d) Zonal Charges

As noted above, the RTO will be divided into four Regions for transmission pricing purposes. Also for transmission pricing purposes, those Regions will be further sub-divided into Zones. Each Region will develop, with stakeholder input, a standard definition of what constitutes a Zone, to be applied consistently within the Region.[18]

Consistent with the Commission's approval of the GridFlorida pricing plan, the cost of transmission facilities installed as of a date certain before the RTO becomes operational ("Existing Facilities") will initially be recovered through Zonal Charges. See GridFlorida, 94 FERC at 62,346-48. The revenue requirement to be recovered in the Zonal Charge will include (i) the revenue requirement of the Existing Facilities of the participant that forms the Zone, plus (ii) the revenue requirement of the Existing Facilities of any TDU within that Zone that joins the RTO, subject to the Commission-approved phase-in plan described below. Each Region will develop a plan to eliminate Zonal

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[17]The definition of Bulk Transmission Facilities should be the subject of further participant discussions.

[18]However, in Florida, the Zones in the GridFlorida compliance filing, which have been approved by the Commission, will be used.

Charges by year 10 of RTO operations, with the costs of Existing Facilities added to the Regional Charge.[19]

This approach recognizes that Existing Facilities represent sunk costs, and that shifting those costs among RTO customers will tend to discourage RTO participation without achieving offsetting efficiency benefits. This approach also recognizes the concern of state commissions related to cost shifts by providing for a reasonable phase-in to regional charges for existing facilities. The approach here is consistent with the one approved by the Commission for GridFlorida, whereby zonal charges will be utilized initially, and phased into a Florida-wide rate.

(e) Regional Charge

Beginning in Year 1 of RTO operations, the cost of new Non-Bulk Transmission Facilities (other than those described above) will be rolled-in to the Regional Charge for that Region. All load taking service within that Region will pay for such new investment through this charge. In addition, as explained above, by year 10 of RTO operations the costs initially included in the Zonal Charges will be included in the Regional Charges for the applicable Region.

The RTO may after Year 10 propose a transition plan, including associated cost shift mitigation, to phase together the four Regional Charges into a single, RTO-wide System Charge.

Again, this pricing structure is consistent with the one approved by the Commission for GridFlorida, as well as consistent with the important goal of addressing state commission concerns about cost shifts. In GridFlorida, the Commission approved a structure where new facilities that were not directly assigned, participant funded, or merchant funded would be rolled-in to a system wide charge. 94 FERC at 62,346-48. Here, to avoid the cost shifts associated with an RTO-wide charge for new regional facilities, the charges for such facilities that are not directly paid for by a market participant will be rolled-in to a Region-wide charge, rather than an RTO-wide System Charge.

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[19] In Florida, the methodology included in the GridFlorida Compliance Filing for phase-in to regional average rates will be used. This approach was approved by the Commission.

(f) System Charge

Beginning in Year 1 of RTO operations, the cost of new Bulk Transmission Facilities (other than those described above) will be rolled-in to the System Charge. All load taking service under the RTO OATT will pay the System Charge.

(g) "Through" and "Out" Service

The RTO will develop a system average point-to-point ("PTP") charge for service “through and out” of the RTO ("T&O Service"). The PTP charge will be based on the revenue requirement of all transmission facilities owned or controlled by the RTO other than those described above, including Existing Facilities, Non-Bulk Transmission Facilities, and Bulk Transmission Facilities. This approach again is consistent with the one approved for GridFlorida. Id.

(h) Grid Management Charge

A Grid Management Charge (“GMC”) will be assessed on all transmission service, including T&O Service. The GMC will recover the administrative and general costs of the RTO that are associated with the planning, operation, maintenance and other functions (e.g., market monitoring, IMA, and start-up costs) of the RTO that are performed for the benefit of all RTO customers and that are not recovered through other charges.

(i) TDU Facilities

The Pricing Protocol provides TDUs purchasing network service the option of (i) an automatic five-year phase-in of their Existing Facilities into zonal charges without a requirement that they demonstrate that those facilities meet the integration standard, or (ii) an immediate roll-in of their Existing Facilities if they can demonstrate that they meet the integration standard.[20] This approach, which was approved by the Commission for GridFlorida, provides significant incentives for TDUs to join the RTO, while minimizing abrupt cost shifts. See GridFlorida, 94 FERC at 62,348-51.

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[20] Each Region will develop a consistent definition of TDUs. In Florida, the definition of TDUs in the GridFlorida compliance filing, which has been approved by the Commission, will be used.

Normally, TDUs are required to demonstrate that their transmission facilities are integrated with those of the transmission provider before they can receive any credit for those facilities. See Pacific Gas and Elec. Co., 81 FERC ¶ 61,122 at 61,505 (1997). The Pricing Protocol is superior to that approach, providing TDUs phased in credit for Existing Facilities over years 1-5, and full credit thereafter, without having to demonstrate that their facilities meet the integration standard. This certainty (i.e., not having to litigate crediting claims on a "case-by-case basis where individual claims for credits may be evaluated against a specific set of facts," Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,742), should enhance TDU participation in the RTO.

For a TDU that does not place a high value on that certainty, the Protocol provides a second option. That is, the Protocol also provides TDUs the option, if they so choose, to seek from the Commission full crediting for their Existing Facilities immediately through a demonstration that their transmission facilities meet the integration standard.

A TDU will receive full credit for any new transmission investment, other than such investment described above, provided it is a participant in the RTO, and subject to the requirements of the Planning Protocol. The Commission has held that credits will not be provided, under any set of facts, if the transmission owner does not join the ISO. See Southern Cal. Edison Co., 92 FERC ¶ 61,070 at 61,255 (2000).

(j) Existing Transmission Agreements

An important issue for any RTO is how existing transmission agreements or ETAs will be treated. The approach in the Pricing Protocol reflects the view that the parties to the agreements are in the best position to determine the changes that are appropriate for their agreements. These agreements vary significantly from one to the next, and what may be appropriate treatment for one ETA may not be appropriate for another. The Pricing Protocol thus as a general rule does not require the amendment of any contract, except to eliminate rate pancaking as discussed below. Instead, parties to all ETAs will be given the right to exercise their Section 205 and 206 rights to propose to convert their contracts to service under the RTO OATT or to amend their contracts to facilitate RTO operations. Entities providing service under contracts that are not converted will be obligated to obtain the necessary transmission service from the RTO to satisfy their obligations under the non-converted contract. A mechanism will be developed to ensure that all transmission service pays its fair share of the GMC.

There are three exceptions to the general rule. The first relates to the phase out of multiple charges (i.e., rate pancakes) for existing long-term Inter-Zonal Service agreements. Inter-Zonal Service is transmission service from one Zone to another, where the same customer bears transmission charges for both Zones. To avoid abrupt cost shifts, the transmission charges levied under an ETA that provides for Inter-Zonal Service will remain in effect during Years 1-5 of RTO operations, and be phased out in equal increments (20% per year) during Years 6-10. If the ETA includes bundled transmission charges, the phase-out of charges will be calculated by reference to the Zonal Charge in effect in Year 5 that applied to the Inter-Zonal Service.[21]

The second exception is to prevent gaming prior to the date the RTO commences operations, i.e., to prevent entities from entering into ETAs prior to RTO operations for the sole purpose of obtaining ETA status. If, after July 12, 2001, a participating transmission owner enters into a new transmission service agreement, or agrees to purchase or provide long-term transmission service (i.e., service for a term that is greater than one year) under an ETA executed prior to that date, the new service provided under such ETA will be converted to RTO service upon the commencement of RTO operations. For all new generator interconnection agreements entered into after July 12, 2001, the SPG RTO shall become an additional signatory to such agreement, to the extent the agreement is not assigned to the SPG RTO. Also, if a participating transmission owner agrees to provide, or to purchase, short-term firm or non-firm service that has a term that extends beyond the date of commencement of RTO operations, that service will convert to RTO service upon the commencement of RTO operations. While an alternative is to include agreements entered into up to the day of RTO operations as ETAs, I believe that such an approach is not warranted due to the gaming that can occur.

Finally, there may be times when the parties have not amended an ETA, but the RTO determines that the non-rate terms and conditions of the arrangement adversely affect its ability to administer its OATT or its operation of the grid. Under this circumstance, the RTO should have a right to seek to amend the ETA to conform it to RTO requirements. See Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,205. Accordingly, the RTO may in such circumstance petition the Commission pursuant to

[21] If more than one customer pays a transmission access charge to deliver the power from source to sink, the transmission access charges associated with the Zone(s) in which the load is not located will be phased out in Years 6-10 only if all parties to the transaction agree that the load consuming the power will receive, on a dollar-for-dollar basis, the reduction in transmission access charges. This proposal goes beyond the Commission's requirements for eliminating pancaking. See Potomac Elec. Power Co., 83 FERC ¶ 61,162 at 61,688-89 (1998) (there is no rate pancaking unless a single customer is paying more than one transmission charge).

Section 206 of the FPA to amend such non-rate terms and conditions. This approach was approved by the Commission for GridFlorida. 94 FERC at 62,352.

6. CONGESTION MANAGEMENT (RTO FUNCTION 2)

Order No. 2000 requires that the RTO ensure the development and operation of market mechanisms to manage transmission congestion. See Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,126. The market mechanisms must accommodate broad participation by all Market Participants and must provide all transmission customers with efficient price signals that show the consequences of their transmission usage decisions. Under Order No. 2000, these market mechanisms for congestion management do not have to be in place when the RTO commences initial operations, but they must be in place one year after initial operations.

Congestion management is a key RTO function and one on which the parties have strong opinions. During the course of the mediation, there was much discussion of this topic. The two models under consideration were a physical rights model and a financial rights model, each with its own pros and cons. A number of parties came to general agreement on the advantages of a model using financial rights and a real-time LMP spot energy market (locational marginal pricing). This model is outlined below and described in more detail in Attachment 3. This model for congestion management provides many benefits with respect to maximizing the use of the grid, providing flexibility for different types of market participants, and minimizing seams issues with neighboring regions. Although the financial rights/LMP model was clearly the preferred model by the majority of stakeholders participating in this mediation, and represents the "best practices" model as derived from the PJM and the SPP experiences, there are many important details about this model that still need to be worked out through continued discussions among transmission owners and stakeholders in the Southeast region. Nevertheless, adoption of the financial rights/LMP model represents significant movement by the plan sponsors in direct response to stakeholder concerns and goals as identified in this mediation process.

Under a financial rights model, the primary means of managing congestion is through voluntary bids to the IMA which indicate the parties' willingness to be redispatched or to "buy through" congestion. The IMA will manage congestion and provide balancing energy through the operation of a real-time spot market in which it directs the dispatch of units to assure maximum use of the grid and provision of energy at least cost. Transmission customers are free to transact bilaterally, subject to congestion charges, and are not required to bid into the spot market. Locational marginal pricing will be used both for congestion charges and spot energy transactions. Transmission rights will be issued by the RTO in the form of financial congestion hedges (FCHs). Parties obtain the financial equivalent of “firm” service through holding FCHs, which hedge against the cost of "buying through" congestion.

The proponents of the **Collaborative Governance Model**, supporting the adoption of a financial rights/LMP protocol for congestion management in the context of this mediation, feel strongly that the following key elements are necessary in order for this model to work:

1. A market design based on financial rights (FCHs) and a real-time LMP spot energy market. The LMP spot market should use nodal pricing for generation and zonal pricing for load, with a nodal pricing option for loads.

2. A capacity requirement applicable to all load-serving entities. The requirement should be designed to promote the efficiency of generation supply and should recognize differences in performance among supply sources.

3. As a part of the capacity requirement, a requirement that loads make capacity resources available to the RTO day-ahead, either through bilateral scheduling and/or through bidding, matching the level of their forecasted needs for the next day. This is called a “balanced resource” requirement. Apart from this requirement, bidding by generators into the market will be voluntary. No generation owner should be required to make resources available to the RTO beyond what it has obligated itself to do via contracting with load to supply capacity resources.[22]

4. A provision for the RTO to perform a day-ahead load forecast and ensure that sufficient capacity is committed day-ahead to provide energy and operating reserves for forecasted load for the next day. The cost of day-ahead capacity commitments will be allocated where possible to the cost-causative customers (meaning those who have not submitted bilateral

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[22] There may be separate requirements to supply ancillary services that are contained in generation interconnection agreements.

schedules or purchased spot energy day-ahead sufficient to cover their actual loads.)[23]

5. A commitment to develop a day-ahead LMP energy market as soon as practicable. Generators and loads will be free to bid into the day-ahead market.

6. To the extent feasible, FCHs that are offered by the RTO in a variety of configurations (e.g., options and obligations).

7. An allocation of FCHs to firm customers, at least initially. Additional FCHs should be auctioned by the RTO. The RTO should also conduct monthly auctions to facilitate a secondary market in FCHs. There should be provisions for mandatory, non-discriminatory release of FCHs in retail access jurisdictions.

8. The use by the RTO of commercially available market rules, software and systems where possible, to minimize the cost of market infrastructure development. The design should accommodate multiple control areas, but should be compatible with future control area consolidation.

Some of the issues that remain to be resolved include questions about how to distribute FCHs as part of the larger issue about how to effect a just and reasonable conversion from today's tariffs to an RTO tariff with market-based congestion management. Clearly, existing long-term load commitments must be taken into account in designing this conversion. Arguably, in many cases the only way to avoid imposing new costs on existing arrangements may be to allocate FCHs consistent with current firm service. This may be true for IOUs and for public power and other load serving entities.

Other parties suggested that cost shifting can be mitigated under an auction regime, by crediting FCH auction revenues back to customers. If customers are outbid in the auction market, they will pay congestion charges but have the auction revenues as an offset. But complete revenue neutrality may not be assured because markets are not perfect, especially immature ones. A contra view holds that forcing all customers to bid for FCHs if they want to hedge congestion charges creates a material risk for those who have existing statutory obligations to serve load at regulated prices. Because of the

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[23] A provision will be developed to address gaming activity such as chronic underforecasting or otherwise leaning on the market.

importance of this issue, continuation of the collaborative stakeholder process to design allocation rules, rules for auctioning of excess FCHs and rules for non-discriminatory release in the event of retail access is imperative.

7. PARALLEL PATH FLOW (RTO FUNCTION 3)

Order No. 2000 requires the RTO to develop and implement procedures to address parallel path flow issues within its region and with other regions. See Order No. 2000 at 31,129-30. The RTO has up to three years after it commences initial operations to satisfy this function.

Under the **Collaborative Governance Model**, the RTO will be responsible for developing and implementing procedures to address parallel path flow issues. Specific procedures to address these issues still need to be established consistent with the following goals. First, the large scope of the RTO should minimize the impact of parallel path flows from other regions. While there may be some parallel path flows near the boundaries with other regions, most of the region should experience relatively minor, if any, parallel path flows from outside the region. Second, the congestion management approach adopted by the SPG RTO should minimize parallel path flow issues within its footprint.

8. ANCILLARY SERVICES (RTO FUNCTION 4)

Order No. 2000 requires the RTO to serve as the provider of last resort for the ancillary services required by Order No. 888. See Order No. 2000 at 31,140. The RTO must allow all Market Participants the option of self-supplying ancillary services or acquiring those services from third parties. In addition, the RTO must have the authority to decide the minimum amounts required and locations of ancillary services, must have direct or indirect operational control of all ancillary services, and must promote the development of competitive markets for ancillary services whenever feasible. Finally, the RTO must ensure that its transmission customers have access to a real-time balancing market.

The **Collaborative Governance Model** approach to ancillary services satisfies each of these requirements. As described below, two of the significant aspects of this approach are: (i) the model anticipates markets for ancillary services once those markets can be supported and (ii) prior to establishing markets, control area operators will be obligated to offer ancillary services to the RTO. Providing for markets once they can be supported is consistent with the Commission's guidance in Order No. 2000, where the

Commission noted that an RTO "must promote the development of competitive markets for ancillary services whenever feasible." Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,141-42. Absence of an obligation to offer ancillary services to the RTO would jeopardize the RTO's ability to act as provider of last resort for these services.

As required by Order No. 2000, under the business plan the RTO will be the provider of last resort for voltage support, regulation, balancing energy, and operating reserves. Transmission customers may self-supply these ancillary services and the RTO will determine whether the self-supply arrangements are adequate. As part of its market design the RTO will implement markets as appropriate for these services. The markets will be phased in over time, under a transition plan that will be developed with stakeholder participation. The RTO will delegate to the IMA the administration of ancillary services.

It is not expected that a region-wide real-time balancing market will be implemented on "Day 1" of RTO operations. See Southwest Power Pool, Inc., 91 FERC ¶ 61,137 (2000); GridSouth Transco, LLC, 96 FERC ¶ 61,067 (2001). Further, as noted above in the market design principles, under this model the balancing market will use nodal pricing for generation. Experience in other regions shows that it is difficult to implement a market with nodal pricing in the absence of market-based congestion management. Rather than have market participants engaged in a collaborative process to design an interim market that will not be part of the end-state design, a regional real-time balancing market should be implemented as part of a planned phase-in of the end-state design.

Prior to the establishment of markets for these ancillary services, the RTO may procure these ancillary services through control area operators. The control area operators will be obligated to provide the RTO with these services for transmission customers in their existing control areas, under their FERC-approved pricing protocols, which may differ by control area. The obligation will be limited to the obligations that a company would have had under an individual company OATT; control area consolidation will not expand this obligation. Control area operators that do not own generation will be responsible for establishing the necessary contractual arrangements to provide the services. The obligation of control areas to provide or procure an ancillary service will be terminated when a workable market exists for that service.

9. OASIS, TOTAL TRANSFER CAPABILITY AND AVAILABLE TRANSFER CAPABILITY (RTO FUNCTION 5)

Order No. 2000 requires an RTO to be the single OASIS site administrator for all transmission facilities under its control and to independently calculate available transfer capacity ("ATC") and total transfer capacity ("TTC"). See Order No. 2000 at 31,144-45.

Under the **Collaborative Governance Model**, the IMA will administer the OASIS and will have the authority to determine ATCs and TTCs for the transmission facilities under the RTO's control. The IMA's responsibilities regarding OASIS administration and calculation of ATCs and TTCs are described in the Operating Protocol. The Operating Protocol provides that the TTCs are determined based on the line ratings, design criteria and other relevant data. The ATCs are determined by the IMA based on the TTCs, transmission reservations, scheduled maintenance of generation and transmission facilities, and in accordance with applicable Regional Reliability Council and NERC standards.

10. MARKET MONITORING (RTO FUNCTION 6)

Order No. 2000 requires that the RTO provide for objective monitoring of markets it operates or administers. The RTO's market monitoring plan should identify market design flaws, market power abuses, and opportunities for efficient improvements and propose appropriate actions. See Order No. 2000 at 31,155-56. Order No. 2000 further provides that the market monitor should: (1) monitor behavior of Market Participants in the region, including transmission owners, to determine if their actions hinder the RTO's ability to provide reliable, efficient, and not unduly discriminatory transmission service; (2) periodically assess how behavior in markets operated by others affects the RTO's operations and how markets operated by the RTO affects behavior in those other markets; and (3) file reports on opportunities for efficiency improvements, market power abuses, and market design flaws with the Commission and other affected regulatory authorities.

The **Collaborative Governance Model** adopts the GridFlorida Market Monitoring proposal, which was approved by the Commission. See GridFlorida, 94 FERC at 62,364-65. However, the market participants and the mediation team strongly support additional enhancements to the GridFlorida model in order to give the Market Monitor additional powers. The provisions of our recommendations for market monitoring are described below.

(1) <u>Structure</u>

The Market Monitor will be an independent corporation ("MonitorCo"), with a three person, independent board. The executive search firm used to assist in selecting the Board of Directors will be used to assist in selecting the board of MonitorCo. The search firm will provide a list of seven candidates to serve on the board. The Transco Board of Directors will choose one person from the list of candidates and the Advisory Committee will choose one person from the list of candidates. The initial two board members selected by the Board and the Advisory Committee will select the third member of the MonitorCo board from the remaining list of candidates provided by the search firm.

After a board member's term expires (or a board member is removed), a new board member will be chosen to replace the exiting member by the same group that selected the exiting member. For example, if the exiting board member was chosen by the Transco Board, the Board will choose the new board member from a list of candidates provided by the independent search firm. Subsequent directors must be selected from a list of at least three candidates provided by an independent search firm. A board member can be removed from the board of MonitorCo upon the affirmative vote for removal of the Transco Board and the Advisory Committee.

The MonitorCo board will choose one individual to act as the CEO of MonitorCo, or it may engage an independent entity to act as Market Monitor. The CEO and other employees of MonitorCo or the independent entity also must be independent. The board of MonitorCo may remove the CEO or independent entity upon a majority vote.

(2) <u>Budget and Funding</u>

To ensure that the Market Monitor will be completely independent from Market Participants and SPG, MonitorCo will have complete authority over its budget, subject only to Commission review. To ensure appropriate input into the budget, the board of MonitorCo will develop a proposed annual budget and provide its proposal to the Transco Board and the Advisory Committee at least 60 days prior to the date a filing with the Commission would be made to recover the costs included in the budget. These costs would be included in the Transco's rates.

Thirty days after providing its proposed budget to the Transco Board and the Advisory Committee, the board of MonitorCo will meet with one representative of each of those entities to discuss the proposed budget and to respond to suggested changes. The board of MonitorCo, however, will not be obligated to make any changes proposed by the Transco Board or the Advisory Committee. The Transco will recover the costs included in MonitorCo's approved budget through its grid management charge. Thus, again, the proposed approach provides a balance that ensures the Market Monitor's independence to establish its budget while providing for non-binding input by affected parties.

(3) Role and Authorities of the Market Monitor

The Market Monitor will examine the structure and operation of the markets it operates or administers; compliance with market rules by Market Participants, any ITCs, the IMA and the Transco, competitive practices of individual Market Participants, any ITCs, the IMA and Transco, and the market as a whole; and it will review market power and allegations of market power abuse. The Market Monitor will have the authority to investigate potential market design flaws, possible exercises of market power, possible violations of market rules or other types of anti-competitive behavior. The Market Monitor will submit regular reports to the board of the Transco and the Advisory Committee on the state of markets, and may make recommendations to the Transco Board regarding changes to SPG tariffs, agreements, and protocols to correct problems that are identified through market monitoring.

The Market Monitor also will have the authority to submit market performance reports and recommendations to the Commission and state regulatory agencies, and, if appropriate, other state and federal agencies. This includes the authority to recommend changes to SPG's tariff, agreements, and protocols. Finally, the Market Monitor will be required to file any reports requested by the Commission or a State utility commission. The plan thus provides an objective basis to observe markets, and provides a number of vehicles through which markets can be changed. In each instance, the Market Monitor will obtain approval of the board of MonitorCo before taking action.

The Commission also noted in Order No. 2000 that sanctions and penalties may be appropriate for certain actions, and that the market monitoring plan must clearly identify any proposed sanctions or penalties and the specific conduct to which they would apply. See Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,156. Here, the Market Monitor can seek to impose mitigation measures only (i) to remedy conduct that is significantly inconsistent with competitive conduct and would result in a material change in market prices or (ii) to mitigate the market effects of a rule, standard, or procedure that allows a Market Participant to impair efficient operation of electric markets.

The Market Monitor may request, and Market Participants and the Transco and IMA shall provide, an explanation or justification regarding specific behavior that the Market Monitor considers may reflect the exercise of market power, may be in violation of market rules, or may otherwise be anti-competitive. The Market Monitor also may conduct further investigations of such specific behavior if it determines that the explanation or justification is inadequate.

The Market Monitor and, as applicable, Market Participants and/or the Transco or the IMA may engage in negotiations in an effort to resolve the situation to the satisfaction of the relevant parties. Also, through demand letter, the Market Monitor may request a Market Participant or the Transco or the IMA to discontinue specific actions that the Market Monitor believes to be an exercise of market power, a violation of market rules, or otherwise anti-competitive. If unable to achieve sufficient corrective action through informal discussions or demand letter, the Market Monitor may submit a complaint regarding specific violations of market rules, exercises of market power, or otherwise anti-competitive behavior directly to the Commission.

In addition to responses related to specific actions by Market Participants and SPG, the Market Monitor may consider and evaluate enforcement mechanisms that may be necessary to assure compliance with market rules, and to prevent or remedy the exercise of market power or other anti-competitive behavior. To the extent the Market Monitor concludes that additional enforcement mechanisms are necessary, it may seek Commission approval of such mechanisms. If the Commission approves the proposed mitigation measures, the Market Monitor would be authorized to impose the mitigation measures on a prospective basis consistent with the terms and conditions approved by the Commission.

Further, the Market Monitor may seek from the Commission general authorization to remedy past conduct that violated market rules that existed at the time of the conduct. However, no remedy may be imposed with respect to conduct that took place prior to the date that the Commission issues an order granting general authority to the Market Monitor to impose relief. For example, if the Commission were to issue an order on October 1 generally giving the Market Monitor the authority to reform bids after the fact, the Market Monitor may not reform bids submitted for dates prior to October 1. This will allow the Market Monitor to seek Commission approval to remedy conduct that violated a market rule if the Market Monitor does not find out until a later date that the market rule was violated, while at the same time giving market participants notice that retroactive relief is a possibility before they are assessed any penalties.

4. Review of Tariff Changes

In addition to the above powers, which were included in the GridFlorida proposal, the SPG Market Monitor should be given powers to review proposed tariff changes by the Transco. Any proposed tariff change, except for a rate change intended to reflect a change in revenue requirements underlying rates for base transmission service or ancillary services or a change in rate design for base transmission service (but not for ancillary services), must be submitted to the Market Monitor at least 30 days before it is filed unless there is an emergency situation or such advance notice otherwise is not practicable. If the Market Monitor does not object to the change, the Transco can file to make the change effective immediately. If the Market Monitor objects to the change, the Transco may still file it at the Commission. However, the Transco may not request to put the change into effect until it is approved by the Commission.

The types of rate changes described above, which can be put into effect subject to refund, are not subject to prior Market Monitor review and may be filed at any time.

11. PLANNING AND EXPANSION (RTO FUNCTION 7)

Order No. 2000 requires the RTO to have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with the appropriate state authorities. See Order No. 2000 at 31,163. In performing this function, the RTO's planning and expansion process should: (1) encourage market-motivated operating and investment actions for preventing and relieving congestion; and (2) accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities. The RTO must satisfy the overall planning and expansion requirement no more than three years after initial operations.

The SPG RTO should have an open and inclusive planning and expansion process. The Planning Protocol for the **Collaborative Governance Model** is included in this Report as Attachment 4. This Planning Protocol is based on the GridFlorida planning and expansion process which the Commission has approved. See GridFlorida, 94 FERC at 62,365-67. The Planning Protocol should be a starting point for the development of the planning and expansion process for the SPG RTO.[24] The principal provisions of this Planning Protocol are described below.

1. Open and Participatory Process

The Transco would adopt a regional transmission planning process designed to identify and to facilitate, in a timely manner, the adoption and implementation of transmission options, including the ability of market participants to offer generation alternatives to these transmission options as well as engage in participant funded transmission projects in order to relieve congestion and maintain and enhance grid efficiency and reliability. This process would encourage and provide opportunities for meaningful, in depth participation by all market participants, regulatory bodies, and other interested parties.

2. Performance of Transmission Planning

Under Section I.A of the Planning Protocol, the Transco would perform, or have performed under its direction, the planning required in order to address requests for transmission service under the SPG OATT. This includes ensuring that the necessary system impact studies are conducted through a single set of studies and determining the additional facilities, if any, necessary to grant the transmission request. This planning would be performed in accordance with the provisions of the Order No. 888 *pro forma* OATT, which are incorporated into the SPG OATT.

Section I.B of the Planning Protocol also provides that the Transco would perform or oversee performance of "Local Area Planning." This is the ongoing planning required by Order No. 888 in order to meet the load growth of Network customers. As noted above, ITCs will perform, subject to Transco review and approval, the Local Area Planning for LSEs served by the ITC transmission facilities, which will include the identification of candidate projects to reduce or eliminate congestion within the ITC footprint. Local Area Planning requires the Transco or the ITC to work with each Load Serving Entity ("LSE") to develop a plan to meet that LSE's future transmission needs. The focus of this planning is on the local transmission system serving existing and

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[24] As noted above, the protocols submitted herewith were not the subject of significant discussions during the mediation process. Therefore, while they provide a useful starting point, my inclusion of the protocols with this Report is not intended to preclude the adoption of different provisions in any final protocol submitted with an RTO proposal.

proposed new Points of Delivery where the SPG RTO will deliver electricity to the LSE. Consistent with Order No. 888, the Transco also would consider expansions or additions to the bulk transmission facilities necessary to satisfy expected load growth.

Section I.C provides that all requests for SPG generation interconnection service ("GIS") should be submitted to the IMA for processing. The IMA will forward requests to the Transco and/or to affected ITCs to perform the necessary studies. The analysis and such requests for GIS should be in accordance with the generator interconnection procedures of the SPG OATT, which, like transmission studies, shall adhere to the single study principle.

3. SPG Transmission Planning Process

The SPG planning process provides for an annual coordinated regional transmission planning process. This process, which is attached as Exhibit 1 to the Planning Protocol, would require the submission of data to the Transco on the expected uses of the system by December 1 of each year. On the following June 1, the Transco would develop a preliminary expansion plan for each of the sub-regions and, after receiving comments and conducting a regional planning conference by October 1, the Transco would post a Final Transmission Expansion Plan on November 15. The development of this plan, however, would not relieve the SPG RTO from its obligation to process requests for transmission service under the SPG OATT pursuant to timelines provided for in Order No. 888.

4. Expansion of Facilities

The Planning Protocol also includes provisions regarding the expansion of facilities under SPG's control. Section II.A of the Planning Protocol sets forth the process whereby the Transco would make the final determination as to the facilities that should be constructed after the planning process identifies the need for new facilities. In making its determination as to the facilities to be constructed, the Transco would be required to consider the estimated costs of the proposed alternatives, impacts on reliability and existing firm service, consistency with the long-term planning for the region, the environmental impacts and availability of permits, and the impact of the alternative on congestion. In determining which alternative to select, the Transco would be required also to consider market solutions, including any proposed merchant or participant-funded expansion and solutions that do not involve the construction of new facilities.

Section II.B of the Planning Protocol addresses the question of responsibility for the construction of facilities. If the Transco owns the facilities being expanded, it would have the obligation to ensure that the construction will be undertaken. If a Participating Owner or ITC owns the facilities being expanded, the Participating Owner or ITC would have the first option of constructing and owning such facilities. However, if the Participating Owner or ITC did not wish to perform the construction or, if it failed to complete construction after being given a reasonable opportunity to do so, then the Transco would perform the construction. In this way a Participating Owner or ITC could not be forced to expend the funds for an expansion. At the same time, Participating Owners and ITCs are prevented from blocking a proposed expansion by refusing to pursue it.

Under Section 1E of the Planning Protocol, a transmission customer may request the SPG to provide and, where applicable, to interconnect, enhanced facilities regardless of whether such facilities have been identified as necessary part of the SPG planning process. The Transco would be obligated to grant the request provided that: (1) the Transco determines that the construction and operation of the facility or enhancement would not adversely affect the reliability of the SPG transmission system; and (2) the transmission customer agrees to pay the entire cost of the difference between what the Transco determines should be constructed or otherwise implemented and what the transmission customer wants to have constructed.

5. <u>Transition Provisions</u>

The Transco may not be able to fully engage in all aspects of planning from the date it goes into operations. Therefore, two planning protocol provisions would allow for a transition from current planning processes to the planning process described above. The first provision relates to Local Area Planning, which requires an extensive knowledge about local area conditions. Section I.B.4 of the Planning Protocol would allow a participating owner to perform the Local Area Planning function for load serving entities served by its transmission facilities during a three-year transition period. The results of the planning performed during this transition period would be subject to the review and approval, or modification, by the Transco. This three-year transition period is consistent with Order No. 2000 which provides that the RTO has three years to assume the planning and expansion function.

The second transition provision is contained in Section I.11 of the Planning Protocol. It would require the Transco, at the commencement of operations, to adopt the most recent 10 year expansion plan of all Participating Owners. This provision would not require the Transco to comply with the existing plans for ten years after it commences operations. Rather, the 10-year plans would operate as the baseline plan for the Transco.

12. INTERREGIONAL COORDINATION (RTO FUNCTION 8)

Order No. 2000 requires the RTO to ensure the integration of reliability practices within an interconnection and market interface practices among regions. See Order No. 2000 at 31,167.

Under the **Collaborative Governance Model**, the RTO will have the authority to coordinate operations with other regions, although this does not preclude other control areas from being part of these coordinating efforts. Even with a single Southeast RTO, seams will exist, and seams issues should be addressed with neighboring regions. The RTO can address these issues, for example, through coordination agreements with adjacent RTOs or transmission owners. These coordination agreements could and should address, *inter alia*: a common set of protocols for ATC/TTC determinations; common TLR and security coordination procedures; coordination of congestion management methods including development of parallel path flow protocols; standardized generation interconnection procedures; coordinated transmission planning and expansion; and coordination of market implementation efforts.

B. The Independent System Administrator Model

This mediation model is sponsored by Georgia Transmission Corporation ("GTC"), MEAG Power, Dalton Utilities, South Mississippi Electric Power Association ("SMEPA"), the City of Tallahassee, Florida ("Tallahassee"), JEA (formerly Jacksonville Electric Authority), South Carolina Public Service Authority ("Santee Cooper"), and Southern Company Services, Inc., acting as agent for Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company and Savannah Electric and Power Company (collectively, "Southern Companies"). These sponsors represent a broad cross-section of transmission owners -- electric cooperatives, municipalities, municipal joint action agencies, state-owned utilities, and investor-owned utilities -- some of which are public utilities subject to the Commission's general jurisdiction, while others are not. Taken together, they own and operate approximately 38,000 miles of transmission assets, of which approximately 11,000 miles are owned by non-jurisdictional entities. These transmission facilities represent a total gross investment of approximately $6 billion. These transmission facilities cover most of Alabama, most of Georgia, portions of northern Florida, a significant portion of Mississippi and much of South Carolina.[25]

The entities joining together to sponsor this model ("the SeTrans Sponsors") have striven to develop a governance model that serves the needs of the competitive market, as well as those of investor-owned utilities and the many public entities whose assets will be subject to the RTO's control. Further, these sponsors have worked diligently and in good faith to modify and develop this model in response to the concerns and goals of the hundreds of other stakeholders actively participating in this meditation process. Nevertheless, for reasons that will be discussed more fully below, I continue to have concerns about the independence and governance aspects of this model in terms of meeting all of the requirements of Order 2000. Because of my continued reservations, and in light of the importance of these issues, I felt that in addition to the discussion of the model contained in this Report it was appropriate to permit the sponsors an opportunity to present their proposal directly to the Commission. The plan sponsors have elected to avail themselves of this opportunity; accordingly, at the request of the SeTrans Sponsors, submitted for the Commission's consideration at Attachment 5 to this Mediation Report, is the "Proposed Mediation Model For A Southeastern Regional Transmission Organization Submitted By The SeTrans Sponsors," (hereinafter referred to as the SeTrans Position Paper).

The Independent System Administrator Model was largely formulated in a unique collaborative effort undertaken by the SeTrans Sponsors that predated this mediation, although the proposal has been modified and developed through the mediation process. The animating concept behind the model reflects an effort to accommodate two very different interests: (1) investor-owned utilities drawn through their experience to a for-profit system operator, and (2) transmission-owning public power entities far more comfortable with a not-for-profit Independent System Operator ("ISO") model. Proponents of both models concur that such an accommodation is critical to optimize competition in the bulk power market and maximize the reliability and efficiency of the regional transmission grid by bringing to the RTO the very substantial transmission systems owned by the public authorities and cooperatives in the Southeast RTO's footprint, but the plan sponsors strongly disagree with each other as to how this accommodation should be realized in the context of a region-wide RTO. While the proponents of the Collaborative Governance Model have attempted to balance these

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25 Fact sheets providing additional detail for each of the SeTrans Sponsors and a summary of pertinent data are included as Attachment A to SeTrans Postition Paper which has been provided as Attachment 5 to this Mediation Report.

different views by modification of their basic "Transco for-profit" model to provide for the formation of, and a role for, an independent, non-profit Market Administrator that will share certain functions with the Transco, the proponents of the Independent System Administrator Model have modified their basic "ISA" model to provide for the formation of, and a role for, a for-profit, Transco that will share certain functions with the ISA. While both models, as modified in this mediation, are therefore "hybrid" models that provide for a division of the RTO functions between a for-profit Transco and an independent market or system administrator, the similarities really end there. In point of fact, the models remain fundamentally different.

Unlike the **Collaborative Governance Model**, which is organized around the key governance concept of an independent, for-profit, transmission owning Transco, the **Independent System Administrator Model** is organized around the key governance concept of an independent, incentive-driven, third party operator (the “System Administrator” or "ISA") that will manage (but will not own) the transmission facilities dedicated to the RTO. The plan sponsors believe that the System Administrator will exhibit the four characteristics identified in Order No. 2000 as critical to an RTO and will be charged with principal responsibility for the essential functions of such an organization identified by the Commission, with the exception of the market monitoring role to be assumed by an independent organization. The public power sponsors of this model feel strongly that this structure, unlike that of the Collaborative Governance Model, has no institutional bias favoring one group of transmission owners over another with respect to decisions affecting all such owners. These plan proponents feel that critical decisions, including decisions related to system planning and expansion, rate design and market design, have a strong potential for bias as long as the RTO simultaneously owns transmission assets and makes decisions affecting its own investment and the investments of others. They argue that having a truly independent third party that does not own transmission assets empowered to make these crucial decisions is also the best way to ensure neutrality of decision-making, which will in turn provide protection and comfort to all other market participants.

This argument is very persuasive, assuming of course that the third party is "truly independent" and meets the other requirements of Order 2000. In this regard, it is important to note that the Independent System Administrator contemplated in this model is **not** the traditional Independent System Operator approved by the Commission in currently operational ISO RTOs. This is evident from a review of the evolution of this model.[26] When the SeTrans Sponsors first began discussing an RTO, they held disparate views regarding a governance structure. For example, some participants wanted to pursue a traditional non-profit independent system operator, while others were strongly opposed to such an arrangement. As a result of the collaborative process among the varying types of transmission owners, a compromise was reached that adopts various aspects of the different governance models. That compromise -- the performance-based, incentive-driven independent operator or System Administrator -- reflects many features of a traditional ISO but, at the same time, addresses the concerns of those that questioned that approach. The competing views of the SeTrans Sponsors were addressed by allowing the System Administrator to earn incentives but only on the "services it provides", unlike a typical Transco which can earn profits on the "assets it operates". Thus, this approach attempts to provide incentives for performance but to prevent the opportunity for discriminatory practices with regard to assets that are "owned" versus "not owned" by the RTO.

The plan proponents submit that the fact that the SeTrans governance model contemplates that an independent, performance-based, incentive-driven organization that will not own transmission within the SPG RTO footprint will be engaged as the System Administrator assures full compliance with the independence requirements of Order 2000 and assures the efficient performance of RTO services. While the sponsoring municipalities and cooperatives are not themselves wedded to institutional profits as the sine qua non of an efficient and effective organization, all the participants believe that financial incentives will provide the System Administrator with the motivation to perform its duties in an appropriate manner.

As a result of compromises made during the mediation, the model described herein departs meaningfully from the format initially contemplated by the SeTrans Sponsors. Specifically, in order to facilitate financing of new investment and divestiture of existing assets, they have added a Transco within the RTO structure that will be invested with certain Order No. 2000 functions inside the Transco's footprint, including the authority to engage in system planning and expansion, interconnection studies and rate design, all subject to the System Administrator's ultimate review and approval. The SeTrans Sponsors have agreed to this significant modification, in the spirit of compromise, out of deference to the view articulated by those supporting a Transco-type model that a degree of autonomy with respect to decision-making on these matters will enhance the financial prospects for private transmission investment. While attempting to accommodate that

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[26] The evolution of this model is described more fully in Section III of SeTrans Position Paper at attachment 5 of this Mediation Report.

view, the SeTrans Sponsors continue to believe that ultimate decisional authority must reside with the System Administrator.

In addition to governance, the SeTrans Sponsors advance below a model that addresses the RTO's remaining characteristics, including its scope, operational authority and control over short-term reliability, as well as the eight RTO functions mandated by Order No. 2000. A few preliminary reflections are made here with respect to those aspects of the model. ***First, it is worth noting that the mediation has demonstrated wide areas of general agreement on some critical functions, including market monitoring, operational authority and short-term reliability.*** Further, with respect to certain functions where disagreement remains, the SeTrans Sponsors observe that decisions need not be made immediately. This is certainly true of "Day 2" market design (congestion management and real-time markets) and proposals for resolving parallel path issues. Finally, the plan sponsors emphasize that the mediation has made plain that these issues are largely severable from one another on the merits, and certainly may be resolved independently of the governance issue.

1. INDEPENDENCE AND GOVERNANCE (RTO CHARACTERISTIC 1)

As previously noted, the modified SeTrans model incorporates a hybrid structure. The RTO will consist of the System Administrator and a Transco, and will include significant input from a Stakeholder Advisory Committee. These entities are discussed briefly below.

- The System Administrator: A performance-based, incentive-driven, independent third party operator that will operate, but will not own, the transmission facilities subject to the RTO's control.

- The Transco: A Transco that will perform several significant functions for the facilities that it owns and will satisfy the independence requirements of Order No. 2000.

- The Stakeholder Advisory Committee ("SAC"): An established committee of stakeholders that will perform significant roles in the formation of the System Administrator, as well as in the on-going operation of the RTO.

a. The Independent System Administrator

The System Administrator is intended to have each of the four characteristics required by Order No. 2000 and will perform all of the eight functions required by the Commission of an RTO, with the exception of Market Monitoring, which will be assigned to another entity. The System Administrator will be a public utility regulated under the Federal Power Act and will be responsible for administering the single RTO-wide Open Access Transmission Tariff ("OATT"). The System Administrator will exclusively exercise the RTO's Section 205 rights. The transmission owners will be responsible for submitting their revenue requirements to the RTO, as well as obtaining any necessary approvals of such revenue requirements. The System Administrator will include those revenue requirements in the OATT rates filed with the Commission.

The System Administrator will be the Security Coordinator for the RTO's region. The System Administrator will be responsible for market design, including the congestion management and real-time balancing models that will be utilized. The System Administrator will also perform the market administration and system operations functions, such as day-ahead resource scheduling and real-time market operations. The latter will include the performance of congestion management, real-time generation dispatch, interchange scheduling, and ancillary services dispatch. In this regard, the System Administrator will determine the settlement prices for purposes of redispatch.

The System Administrator will be responsible for OASIS administration and ATC/TTC calculations. The System Administrator will have ultimate planning authority and perform regional studies and planning. Similarly, the System Administrator will be responsible for the rate design for RTO-wide service and service outside and through the Transco footprint. In addition, the System Administrator will be responsible for all interconnections by generators and will have coordination responsibility, as well as review and approval authority over all interconnections within the Transco's footprint. The System Administrator will also perform any remaining functions required by Order No. 2000.

The System Administrator will be selected using a process that relies heavily on stakeholder input, while at the same time providing transmission owners some comfort that the entity selected to operate their assets will be competent. The selection process will begin with the Stakeholder Advisory Committee ("SAC") developing selection criteria that (at a minimum) will include the following:

- The System Administrator will not be a market participant;

- The System Administrator, its employees, and its directors will be prohibited from maintaining a financial interest in any market participant;

- The System Administrator will not own transmission, generation or distribution facilities in the region served by the RTO; and

- The System Administrator must demonstrate it is capable of operating the transmission system.

Although the precise criteria will be developed through the collaborative process, the SeTrans Sponsors believe that candidates for the System Administrator should be encouraged (either through explicit requirements or positive evaluation factors): (i) to establish a special advisory role for state public service commissions outside of the context of the SAC; (ii) to form a local board of directors that is easily accessible; and (iii) to employ experienced, capable operators.

The SAC will then choose a professional search firm to assist in designating and selecting a pool of viable candidates. The SAC and participating transmission owners will be provided the opportunity to interview candidates in an open forum and to request pertinent information. Following the identification of candidates by the search firm, the SAC and participating transmission owners will also be permitted to add to the list of candidates and comment in writing upon any candidates considered unacceptable. While transmission owners will participate in the SAC process for purposes of developing criteria and interviewing candidates, they will <u>not</u> have a voting interest on the SAC for purposes of nominating a slate of System Administrator candidates. Once a list of at least four viable candidates is developed, the transmission owners that will participate in the RTO (including the Transco if it is formed at that time and owns transmission assets) will select one candidate to act as the System Administrator. Designation of the System Administrator will be submitted to the Commission for comment and approval. Any successor System Administrator will be selected in the same manner as the initial System Administrator, including approval of the Commission. Any such successor System Administrator will be required to comply with all existing agreements of its predecessor.

This selection process provision, whereby transmission owners will participate in the SAC process for purposes of developing criteria and interviewing candidates but will <u>not</u> have a voting interest on the SAC for purposes of nominating a slate of System Administrator candidates, represents a compromise reached during the mediation process in response to market participant concerns that the TO's were too heavily involved in the selection of the System Administrator. While this compromise represents a substantive modification to the selection process, the fact that the TO's will ultimately select the ISA still causes many market participants concern.

The System Administrator's authority and responsibilities will be set forth in a single, multilateral contract between the System Administrator, the Transco and all participating transmission owners (hereinafter "System Administrator Responsibility Agreement" or "SARA"). The form of the SARA will be developed through the collaborative process and will be included in the formation documents that will be filed with the Commission. The System Administrator's method of compensation, including appropriate incentives (both positive and negative) for performance, will be established in the collaborative process and included in the SARA. The SARA will have an initial term of at least five years with annual evergreen extensions. (This feature was well received by the market participants and suggested for the IMA in the Collaborative Governance Model). In addition, that contract will include standards and criteria to gauge the performance of the System Administrator.

The System Administrator will also enter into a Transmission Operating Agreement ("TOA") with each transmission owner (including the Transco) that will be filed with the Commission. The TOA will ensure that the System Administrator exhibits the characteristics and performs the functions required by Order No. 2000. The TOAs will be largely pro forma, but will contain additional provisions, as necessary, to accommodate the requirements of certain transmission owners (such as maintenance of tax exempt status of bonds issued by non-jurisdictional municipal transmission owners). The TOA between the System Administrator and the Transco will be the pro forma TOA revised to accommodate the limited functionality allowed the Transco. As described further below in connection with the RTO's operational authority, the TOAs will assure that the RTO is able to exercise full operational authority under Order No. 2000. The TOAs will also provide for full recovery through the RTO's OATT of the transmission owners' revenue requirements and will provide for the distribution of associated revenues from the RTO's charges to the transmission owners.[27]

SeTrans Sponsors submit that an important element of the model is that, unlike the independent, stakeholder selected board of the Transco in the Collaborative Governance Model, any individual System Administrator can be removed for cause during the term of the SARA and replaced with a new System Administrator. The SARA will provide the

[27] The TOAs will not impede the System Administrator's ability to perform the required functions of an RTO. However, the TOAs will contain terms and conditions that might be needed to honor preexisting agreements and to address any specific requirements of an individual transmission owner.

conditions for any such termination. Such removal would be subject to approval by the Commission and would only be available in the event of serious malfeasance. Since the System Administrator would not own the underlying transmission assets, such a removal should be able to be effectuated with relative ease.[28] In contrast, SeTran Sponsors argue, it would be nearly impossible to remove from service an RTO that consisted of a poorly performing Transco because of its ownership of transmission assets.

Of course, the short answer here is that accountability to the RTO from the independent board of a Transco is typically accomplished by means of performance measures and, if necessary, removal of one or more of the board members. Ownership of transmission assets by the Transco would not appear to impose an impediment to this. In contrast, the "independent board" that is contemplated in the ISA model is the shareholder board of this special interest LLC third party System Administrator, not a stakeholder or shareholder board or even a board selected by stakeholders or shareholders within the SPG RTO footprint. This fact, when considered in the context of the selection and removal process for the System Administrator described above, underscores my continued reservations regarding the issue of independence under this model.

b. The Stakeholder Advisory Committee

A Stakeholder Advisory Committee ("SAC") will perform several important roles both in the formation of the RTO (as discussed above) and after it commences operation.[29] The SAC will consist of representatives of all stakeholder groups. Although the exact composition of the organization's participants will be the subject of further discussion in the collaborative process, the SAC is expected to include:

- Investor-Owned Utilities
- Power Marketers and Brokers
- Generation Owners and Developers
- Transmission Dependent Municipals and Cooperatives
- Transmission-Owning Cooperatives
- Transmission-owning Municipal Joint Action Agencies and Municipals
- State Governmental Agencies/Consumer Advocates

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[28] To the extent that the System Administrator owns or controls any software, hardware, etc., that might be needed for the operation of the RTO, the SARA will establish a procedure by which such assets will be conveyed to the successor System Administrator in the event of termination.

[29] The SAC is modeled after the SAC proposal in the GridFlorida filings

- Industrial End Users
- Federal Utilities
- State-Owned Authorities

The stakeholder groups will each select their representatives and form of representation. Each representative will have one vote, and the SAC will act upon majority rule of the representatives. The transmission owners will not have a majority vote on the SAC, nor will they be able to veto a proposal.

The SAC will have an ongoing role of providing advice to the System Administrator and Transco. That input will be governed by a “Bill of Rights” that will ensure that the SAC has the right to: make presentations to the Board and Management of both the System Administrator and the Transco; make written reports and recommendations to the System Administrator and Transco; and present minority positions to the System Administrator and Transco. The RTO will have an open information policy, which will facilitate the SAC’s ability to participate meaningfully in the RTO’s activities. Participants in the SAC will neither be subject to fees nor provided reimbursement for their expenses.

c. The Transco

In order to accommodate those utilities interested in divesting their transmission assets and to facilitate the financing of the resulting acquisitions, the SeTrans model has been modified in order to provide for the creation of, and a role for, a Transco. The Transco will perform several specified functions for the facilities that it owns. As an initial matter, it will own the existing transmission facilities within the Transco’s footprint and have the option to build new transmission facilities within that area. The Transco will also develop the rate design for load in its footprint, subject to System Administrator review and approval. In addition, the Transco will perform system studies and planning within its footprint, subject to System Administrator review and approval, unless the resulting improvement would cause a change in flows greater than 5% on any constrained facility outside of the Transco’s footprint (in which case the System Administrator will have primary planning responsibility).[30] Customers seeking generator interconnections within the Transco’s footprint will go to the System Administrator for such interconnection. The Transco will perform its generator interconnection studies at the direction of the System Administrator and using standards established by the System Administrator. In order to obtain any of this functionality, however, the Transco must

[30] As discussed below, market participants will be able to provide input into that planning process.

satisfy the Commission's requirements on independence and be unaffiliated with any market participant. (In essence, this mirrors the level of functionality contemplated for an ITC under the Collaborative Governance Model).

d. Procedure for Further Development of Organic Documentation and for Changes to Allocation of Responsibilities to System Administrator.

The RTO's organic documents will be developed in the context of an open collaborative process including all stakeholders who wish to participate.[31] Those documents include: the SARA and the pro forma TOA; the OATT, including rate design, market design, congestion management, and ancillary service schedules incorporated therein; Planning and Operating Protocols; procedures for addressing Parallel Path Flow issues; OASIS Protocols and procedures for calculating ATC/TTC; and Planning and System Expansion Protocols. Following these collaborative efforts, the RTO and transmission owners will make the appropriate filings under Sections 203 and 205 of the Federal Power Act.

In order to ensure that neither the System Administrator nor the Transco can too easily encroach on the functions assigned to the other, the initial division of authority can only be changed by a Section 206 complaint to the Commission. In any such complaint, the proponent of the change will have to demonstrate that the status quo, without the proposed change, is unjust and unreasonable or unduly discriminatory, and that the proposed change is just and reasonable and not unduly discriminatory. It is the intent of the SeTrans Sponsors that the functions remain fixed for at least the first five years after commercial operation of the RTO.

2. SCOPE AND REGIONAL CONFIGURATION (RTO CHARACTERISTIC 2

Order No. 2000 requires the RTO to serve an appropriate region of sufficient scope and configuration to permit the RTO to effectively perform its required characteristics and functions and to support efficient and non-discriminatory power markets. Order No. 2000, slip op. at 246. The Commission in Order No. 2000 declined to establish regional boundaries, but did note that given the characteristics and functions for an RTO set forth in Order No. 2000, the "regional configuration of a proposed RTO should be large in scope." Order No. 2000, slip op. at 254. The Commission also set forth a set of factors that will affect the regional boundaries of the RTO, including:

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[31]Following its selection, the System Administrator will participate in the collaborative process as a consultant and facilitator.

- facilitating essential RTO functions and goals;
- recognizing trading patterns;
- mitigating the exercise of market power by regional transmission entities;
- not unnecessarily splitting existing control areas or existing regional transmission entities; and
- encompassing contiguous geographic areas and highly interconnected portions of the grid while taking into account existing regional boundaries (such as NERC regions) and international boundaries.

Order No. 2000, slip op. at 259-262. In Order No. 2000, the Commission also stated that all transmission facilities within the RTO should be included in and controlled by the RTO, while recognizing that there may be legal or other impediments preventing such inclusion. Particularly important in this regard, the Commission found that a "properly formed RTO should include all transmission owners in a specific region, including municipals, cooperatives, Federal Power Marketing Agencies (PMAs), Tennessee Valley Authority and other state and local entities." Order No. 2000, slip op. at 589. In its Mediation Order, the Commission further clarified that it desired a single RTO for the entire Southeast, while reserving judgment on the inclusion of Florida and the Southwest Power Pool.

In the Southeast, a very large portion of the transmission grid is owned by electric cooperatives, municipal utilities, state agencies, and federal utilities, such as the Tennessee Valley Authority -- all of which are not subject to the Commission's general jurisdiction. For example, non-jurisdictional entities participating in the SeTrans effort own approximately 11,000 miles of transmission facilities. Without the participation of these non-jurisdictional owners, an RTO will be riddled with holes and thus will not be able to maintain reliability, effectively perform its required functions, resolve parallel flow and constraint issues, and support efficient and non-discriminatory power markets.[32] An RTO without these non-jurisdictional entities will fall far short of the Commission's goal of forming an RTO that encompasses the entire Southeast. With the inclusion of

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[32] A clear example of this need for non-jurisdictional participation involves the Integrated Transmission System in Georgia ("Georgia ITS"), which is comprised of the transmission assets of Georgia Power Company, GTC, MEAG Power and Dalton Utilities. Without the assets of all of these owners, the transmission system in the State of Georgia will not function in the way the Commission desires.

these non-jurisdictional entities (and others such as TVA), buyers and sellers will be better able to access broader markets, which in turn promotes competition.

A fundamental tenet of the SeTrans model is that non-jurisdictional owners must be accommodated and encouraged to participate. The SeTrans Sponsors attempt to satisfy this tenet through an RTO that does not own transmission and uses TOAs to address individual owner issues. SeTrans' success in this effort is best demonstrated by the integral involvement in the effort by GTC, MEAG Power, Dalton Utilities, SMEPA, Tallahassee, JEA and Santee Cooper, all of which are non-jurisdictional transmission owners.

The proponents of the ISA model assert that non-jurisdictional entities preferred the SeTrans model because of the independence of, and the concentration of RTO functions in, the System Administrator. And this may very well be true, inasmuch as this model avoids concerns of institutional bias because the System Administrator will be independent of all market participants and will not own generation, transmission or distribution in the RTO area. However, at least as important, if not more so, to the support of these public power sponsors for this model is the commitment, up front, for full recovery of the costs of their assets on day one of RTO operation and grandfathering of existing contracts. These issues will be addressed more fully below.

3. OPERATIONAL AUTHORITY (RTO CHARACTERISTIC 3)

The third minimum characteristic of an RTO is that it must have operational authority for all transmission facilities under its control. To satisfy this requirement, the RTO must ensure that any operational authority shared with a market participant does not adversely affect reliability or provide an unfair competitive advantage. In addition, the RTO must act as Security Coordinator of the facilities under its control. Order No. 2000, slip op. at 277-282.

Under the SeTrans model, the System Administrator will have operational authority for all transmission facilities under its control through the TOAs. The TOAs will be pro forma documents created through the collaborative process. The SeTrans Sponsors expect that the collaborative process will consider transmission operating agreements developed by other RTOs in crafting a pro forma TOA that reflects the best industry practices. The TOAs will, for the most part, be substantially identical, but they will take into account issues of concern for individual transmission owners, such as conditions needed to preserve the tax exempt status of non-jurisdictional entities. The TOAs will ensure transparency such that all the requirements of Order No. 2000 will be satisfied by the RTO. In other words, transmission owners will not be able to exert control that could affect the reliability of the system or provide them with an unfair competitive advantage. Any concerns in this regard should be ameliorated by the development of the pro forma TOA in the collaborative process. Moreover, the System Administrator will file the TOAs, along with other organic documents, when it seeks RTO status from the Commission.

The System Administrator will be the NERC-defined Security Coordinator for the facilities under its control to further ensure its ability to exercise operational authority over regional transmission facilities. As Security Coordinator, the System Administrator will be responsible for all Security Coordinator functions defined in NERC Operating Policy, including specifying ancillary service requirements, performing system studies, conducting security analysis, developing special operating procedures, implementing Transmission Loading Relief ("TLR") procedures, and directing and coordinating system restoration activities.

In Order No. 2000, the Commission made clear that an RTO is not required to operate a single control area. Order No. 2000, slip op. at 279-80. Accordingly, the System Administrator will operate multiple control areas as defined by NERC. This arrangement will minimize cost by using existing facilities under the overall control of the System Administrator. Control areas that are maintained by participants in the RTO will be required to follow the direction of the System Administrator with respect to transmission service and reliability matters through either direct or indirect control. See Carolina Power & Light Co., et al., 94 FERC ¶ 61,273, p. 61,995 (2001) ("GridSouth") (approving the use of multiple control areas). To be clear, the System Administrator will be responsible for directing the operations of the transmission system, monitoring and controlling real and reactive power flows and voltages levels, and scheduling and directing the operation of reactive resources. The control area operators will retain physical control of their systems (e.g., physically switch transmission elements into and out of operation, remove equipment from service, etc.), but they will do so pursuant to operating procedures approved by the System Administrator and subject to the direction of the System Administrator. The Commission has endorsed such a division of responsibility between an RTO and control areas in a number of cases, including the recent decision in PJM Interconnection, LLC and Allegheny Power, 96 FERC ¶ 61,060, p. 61,212 (2001).

The SeTrans Sponsors believe that all load-serving entities ("LSEs") should take responsibility for planning and supplying generation resources to meet their load. This is particularly the case in the Southeast where the States have not adopted retail competition and most utilities continue to have an obligation to serve the public in their service territories. Accordingly, it is a feature of the proposed model that all entities must submit balanced schedules of generation and load to the RTO. Specifically, all market participants must schedule sufficient generation to meet their projected load plus losses. The real-time balancing market will resolve any mismatches between scheduled and actual performance but, in the first instance, the market participants must come forward with plans to serve their load without "leaning" on their neighbors.[33] The resources that can be specified include self-generation, purchases from others, load reductions or other appropriate arrangements that market participants choose to pursue. Regardless of the approach used, all market participants will bear responsibility for serving their own load similar to the way that control areas currently operate.

4. SHORT-TERM RELIABILITY (RTO CHARACTERISTIC 4)

Order No. 2000 requires that an RTO have exclusive authority for maintaining the short-term reliability of the grid it operates. Among the areas identified by the Commission as being associated with short-term reliability are the following: (i) the exclusive authority to receive, confirm and implement interchange schedules; (ii) the right to order redispatch if necessary for reliable operation of the transmission system; and (iii) the authority to approve scheduled transmission outages. In addition, the RTO must perform its functions consistent with established reliability standards, and must notify the Commission if these standards prevent it from providing reliable, non-discriminatory transmission service. Order No. 2000, slip op. at 315-22.

Under the SeTrans model, the System Administrator will ensure the short-term reliability of the integrated transmission system it operates. Consistent with Order No. 2000, the System Administrator will be responsible for receiving, confirming and implementing all interchange schedules, through either direct or indirect control. As noted above, market participants will provide balanced generation and load projections for each hour of the next day. Using this information, the System Administrator will develop an operating plan to determine the amount and location of needed ancillary services, transmission reconfiguration, redispatch options, or must-run reliability generation. At an established time later during the day, the System Administrator will acquire any additional ancillary services (above those acquired on a longer-term basis) from a bid-based market.

[33] To discourage intentional mismatches between scheduled and actual performance, the RTO will impose financial penalties on market participants that consistently mismatch schedules. The exact nature of such penalties has yet to be determined, but the concept is to impose a penalty after a limited number of significant violations.

During current day operations, the market participants will refine their hourly projections to better balance load and generation. As more information is known, the System Administrator will update its original plan and allow the bid-based market to respond. In real-time, moment-to-moment balancing of load and generation will be accomplished by the control areas within the RTO responding to Area Control Error ("ACE"). The System Administrator (by contract) will have the right to order redispatch of generation to alleviate congestion and to ensure that the moment-to-moment reliability requirements of the load and transmission system are met.

In addition, the System Administrator will have the right to order redispatch in emergency conditions. These "emergency" conditions will be limited to reliability situations that require generation adjustments for security problems that cannot be resolved using the ancillary and congestion management markets due to a failure of the market to offer a sufficient quantity of resources at some price or as a result of some catastrophic condition. In other words, the System Administrator will not call on such resources when sufficient resources have been offered through the ancillary markets, even if the price for such resources is high. Moreover, the System Administrator will not call for a reduction in generation resources without supplying appropriate replacement energy to maintain the balance of supply and load. Finally, these emergency redispatch provisions will not prevent generation owners from offering generation services into the wholesale energy market on a firm basis or create a situation in which the generation is significantly devalued as a result of the redispatch obligation. It is currently expected that the limitations on emergency redispatch, as well as the appropriate compensation, will be established in the generators' interconnection agreements with the System Administrator.

The System Administrator will also provide oversight and have final authority over scheduled transmission outages. This responsibility will include reviewing and approving all scheduled transmission outages of the transmission owners to minimize disruptions in transmission service. The System Administrator will also coordinate planned generator outage schedules to ensure reliability of the transmission system. Accordingly, the System Administrator will satisfy the Commission's short-term reliability characteristic. See GridSouth, 94 FERC at p. 61,995 (holding that a similar proposal regarding short-term reliability satisfied the requirements of Order No. 2000).

B. <u>RTO CORE FUNCTIONS</u>

1. <u>Tariff Administration</u>.

In Order No. 2000, the Commission determined that the RTO must be the sole provider of transmission service and sole administrator of its own OATT. The Commission clarified that this authority includes the evaluation and approval of all requests for transmission service, including new interconnections. In addition, the Commission determined that transmission customers must not be charged multiple access charges. Order No. 2000, slip op. at 330-32.

Consistent with the requirements of Order No. 2000, the System Administrator will develop and file a “system-wide” OATT and will be the sole provider of unbundled transmission service over the facilities that it operates. The System Administrator will be the sole tariff administrator of a Commission approved OATT, with the right to file for rate changes under Section 205 of the Federal Power Act. The System Administrator will be responsible for the rate design for RTO-wide service and service outside and through the Transco footprint. The Transco will have authority to develop the rate design for service to load in the Transco’s footprint, subject to System Administrator review and approval. Each transmission owner will have the right at any time, with appropriate regulatory approval, to change its annual revenue requirement (including incentive mechanisms) payable to the transmission owner by the RTO.

Based on current Commission precedent, the SeTrans Sponsors expect that all load would be under the OATT (with appropriate treatment for grandfathered agreements). In this regard, the SeTrans Sponsors anticipate that they would take network transmission service from the RTO for their retail and bundled wholesale customers. Specifically, participating transmission owners would execute a contract with the System Administrator for such service unless an owner is legally prohibited from doing so or faces the loss of eligibility for tax exempt financing by engaging in such a contract, in which case the terms of service must be modified to address such impediments.

The System Administrator will have the sole authority to receive, evaluate, and approve or deny all requests for transmission service (including interconnection service). This approach will provide generators with a “one-stop” approach to obtain interconnection and delivery service. The System Administrator will be responsible for all interconnections by generators and will have coordination responsibility as well as review and approval authority over all interconnections within the Transco’s footprint. Although the Transco will have responsibility for interconnections in its footprint, customers seeking such interconnections will have access to “one-stop shopping” by applying to the System Administrator. The Transco will perform its generator interconnection functions at the direction of the System Administrator and using standards established by the System Administrator.

The RTO tariff rate design will be developed through a stakeholder process, and thus it is premature to try to describe it in great detail. In general terms, it is expected that the rate model will provide full cost recovery for all participating transmission owners and will include incentives for new construction. Some of the key principles of the SeTrans model concerning rate design are outlined below:

1) All facilities rated 40kV and above are eligible for inclusion (subject to the consent of the owner of such facilities) in the RTO from the initial operation of the RTO. Transmission owners desiring to include such facilities will not be subject to any functionality or other test for inclusion.

2) Transmission owners will be entitled to full revenue requirement recovery for any facilities included in the RTO, beginning at initial RTO operation.

3) There will be a "rolled-in," system-wide point-to-point rate.

4) There will be "license plate" rates for network service, based upon the zone where the loads are located. The specific zones will be determined through the collaborative process.

5) Multiple access charges within the RTO area will be eliminated.

It is anticipated that the model will include cost shifting mitigation measures, but it must be emphasized that there are several types of potential cost shifting concerns that have been discussed in the mediation. One type involves cost shifts due to the transition from a license plate rate to a postage stamp rate; a second involves cost shifts arising from the recognition of all transmission facilities within the RTO; and a third involves cost shifts due to the loss of existing transmission revenues resulting from the elimination of rate "pancaking". The SeTrans Sponsors are very concerned about the first because it could have a significant impact on the rates of end users. With respect to the second, the discussions have suggested that the impact would be very small. **Based on that assumption, the SeTrans model does not propose to "phase-in" recognition of investment of participating transmission owners over some multi-year period. Instead, the SeTrans model contemplates recognition of transmission investments**

from the outset of RTO operations. This is a key element of the model for most coops and munis. With respect to the loss of transmission revenues due to the elimination of rate pancaking, such cost shifts will need to be addressed when their magnitude is better understood. All of these issues will be explored in more detail in the collaborative process.

In addition, **the RTO rate design will honor all Existing Transmission Agreements ("ETA"), including transmission service agreements, interconnection agreements, interface agreements and transmission ownership agreements effective as of July 12, 2001 with no generic abrogation of the ETAs**. See Order No. 2000, slip op. at 602 ("it is not appropriate to order generic abrogation of existing transmission contracts."); GridSouth, 94 FERC at 61,999 (allowing the grandfathering of ETAs). This is another key element of this model, particularly for public power entities like Georgia ITSC. However, the System Administrator may, pursuant to Section 206, propose an amendment to any non-rate term or condition of an ETA that has an unduly adverse impact on its ability to administer the Tariff or its operation of the grid. The SeTrans model contemplates that license plate rates will remain in effect at least through December 31, 2012, to coincide with the term of the Georgia ITS Agreements. Any ETA that conveys firm transmission rights will be allocated congestion rights consistent with the congestion management system. Current individual Tariff transmission service agreements ("TSAs") will be converted to RTO TSAs.

2. Congestion Management.

Order No. 2000 requires that an RTO ensure the development and operation of market mechanisms to manage congestion. The Commission determined that responsibility for operating these market mechanisms must reside with the RTO or another entity that is not affiliated with any market participant. The Commission declined to endorse any single model or pricing approach, but instead stated that it "will allow RTOs considerable flexibility to propose a congestion pricing method that is best suited to each RTO's individual circumstances." Order No. 2000, slip op. at 384. With respect to implementation, the Commission allowed RTOs to defer implementation of market mechanisms for managing congestion for a period of one year after start-up. Order No. 2000, slip op. at 380-86.

The SeTrans model regarding congestion management is a work-in- progress and is intended to facilitate tradable transmission rights and secondary markets for such rights, promote efficient regional dispatch and maintain system reliability. Expectations are that the "Day 2" congestion management plan ultimately adopted will be the fruit of a full collaborative process. Given this intent for further development and input and recognizing that the specific details of the plan are still under consideration, the congestion management plan concepts will be briefly summarized.

Firm Transmission Rights ("FTRs") will be allocated to firm transmission customers based on the flowgates associated with the transmission service that they have reserved. See GridFlorida LLC, et al., 94 FERC ¶ 61,363, p. 62,353 (2001) (accepting, in theory, the use of a flowgate/physical rights model to manage congestion.) Transmission service will be reserved between specific resources (point(s) of receipt) and specific loads (point(s) of delivery), but the FTRs will be assigned on the specific flowgates impacted by the service request. Since the FTRs are associated with flowgates (instead of specific contract paths), they will be usable for any transmission reservation that involves the affected flowgates. Consequently, an FTR owner that wishes to schedule transmission service along a different contract path than the original reservation will be able to use the FTRs it holds to the extent the new transmission schedule impacts the same flowgates.

After initial assignment to a transmission customer, FTRs can be reassigned by the original owner to any party (subject to registration with the RTO). Unlike some approaches, this model provides that a holder of FTRs will receive no benefit unless it actually uses its rights. Hence, a holder of FTRs will have an incentive to sell any unused FTRs to others. At the same time, a holder of FTRs will not be able to prevent others from using the flowgate. If an FTR is left unused, transmission service will be provided to others on a non-firm basis and the FTR holder will receive no compensation.

Congestion will be managed by the System Administrator using voluntary hourly bids for redispatch. Bids will include both "incremental" prices (prices market participants would be willing to receive to increase generation or to decrease load) and "decremental" prices (prices market participants would be willing to pay to decrease generation or to increase load). The generator must obtain any applicable regulatory approvals associated with the price quotations. Redispatch will occur as necessary to maintain system security and alleviate congestion. The bids will be used to calculate the locational marginal price ("LMP") for the flowgate nodes, which in turn will determine the net congestion cost to be allocated to those entities responsible for the congestion.

Redispatch will be available for all types of transmission customers. Non-firm customers (i.e., customers without FTRs) may choose to pay redispatch costs and avoid curtailment (if a redispatch solution exists) or decline to do so and be physically curtailed when congestion occurs. Similarly, external customers (i.e., those causing unscheduled loop flows) may request transmission service and, to the extent that it is available, pay the transmission service charges and congestion costs associated with the loop flows and thereby avoid physical curtailment during periods of congestion. Prior to redispatch, physical curtailment will be implemented consistent with the NERC TLR procedures to remove non-firm (internal and external) customers preferring physical curtailment over increased transmission cost. If congestion persists after eliminating these flows, the System Administrator will attempt to alleviate the limitations using redispatch based on the incremental and decremental bids submitted by generators. As a last resort, physical curtailment consistent with NERC TLR procedures will be implemented. At settlement, congestion costs will be allocated to those customers causing the congestion. Such costs will be first allocated to the customers without FTRs and then to customers with such rights.

The proposed congestion management concepts provide a feasible approach that will establish clear and tradable transmission rights, promote efficient regional dispatch, facilitate the emergence of secondary markets for transmission rights and provide market participants the opportunity to hedge their exposure to congestion, while maintaining system reliability.

3. Parallel Path Flow.

In Order No. 2000, the Commission determined that an RTO must develop and implement procedures to address parallel path flow issues within the region and in other regions. Recognizing the complexity of the issue and the varying severity of the problem among different areas of the country, the Commission established a three-year period to implement measures to address parallel path flow issues between regions. Order No. 2000, slip op. at 390-93.

Consistent with these requirements, the System Administrator will implement procedures to address parallel path flow issues within its region and with other regions. Since service will be provided under a single OATT, parallel path flows within the region will be internalized. By virtue of the inclusion of substantial non-jurisdictional transmission facilities in the RTO, the System Administrator will be able to internalize many more flows than an RTO without such public power participation. To the extent parallel path flows from other regions can be identified (through the NERC tagging process or another means), their relative transmission priorities can also be determined. Under the SeTrans model, customers causing these external transactions may agree, if there is ATC, to pay any transmission service charges and the congestion costs associated with the parallel path flow they impose and thereby avoid physical curtailment. In addition, a customer imposing a parallel path flow can purchase FTRs to mitigate exposure to such congestion costs. Although this approach should satisfy the requirements of Order No. 2000,[34] the System Administrator will also continue to work with other regions to adopt more comprehensive parallel path flow mechanisms within three years of startup.

4. Ancillary Services.

In Order No. 2000, the Commission determined that an RTO must serve as provider of last resort of all ancillary services required by Order No. 888 (and subsequent orders). The Commission clarified that the RTO could fulfill its ancillary service obligation through a variety of means, including contractual arrangements, control of specified generation facilities or market mechanisms. The Commission found that all market participants must have the option of self-supplying or acquiring ancillary services from third parties, subject to restrictions imposed by the Commission. The Commission ruled that the RTO must have authority to decide the minimum required amounts of each ancillary service and the locations at which these services must be provided. The Commission also concluded that an RTO must ensure that customers have access to a real-time balancing market that is developed and operated by either the RTO or another entity that is not affiliated with any market participant. Order No. 2000, slip op. at 420-26.

Consistent with these requirements, the System Administrator will serve as the provider of last resort for all ancillary services required to be offered to market participants. All market participants will have the option of self-supplying or acquiring ancillary services from third parties consistent with Commission policies. However, the System Administrator will have the authority to decide the minimum required amounts of ancillary services and, if necessary, the locations at which these services will be provided.

The ancillary services that will be provided include the ancillary services required in Order No. 888. The System Administrator will take bids for all of those services, except Scheduling, System Control and Dispatch Service. The cost of that service will be based upon the System Administrator's costs, while all other ancillary services will reflect the cost of acquisition from the market. To the extent that a market participant desires to sell such services to the RTO at market-based rates, it must obtain the

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[34] In this regard, the SeTrans Sponsors submit that this model is superior to that approved by the Commission in GridSouth because it allows the customer causing the loop flows to avoid curtailment by paying the associated redispatch costs or by purchasing FTRs. Compare with GridSouth, 94 FERC at p. 62,002.

appropriate regulatory approval. The details of the ancillary services will be developed as part of the collaborative process.

5. **OASIS/TTC/ATC.**

In Order No. 2000, the Commission found that an RTO must be the single OASIS site administrator for all transmission facilities under its control. The Commission reaffirmed that an RTO should calculate ATC values based on data developed (partially or totally) by the RTO. In the event of a dispute over ATC values, the RTO's values should be used pending the outcome of the dispute. Order No. 2000, slip op. at 432-35.

Consistent with these requirements, the System Administrator will be the single OASIS site administrator for all transmission facilities under its control and will independently calculate TTC and ATC. TTC and ATC will be calculated on individual flowgates of relevant concern. In addition, the System Administrator will post TTC and ATC to reflect contract paths based upon the ATC of all the flowgates involved in the contract path, as is the case today. In the event of a dispute over the appropriate TTC or ATC, the System Administrator's determination will govern pending the resolution of the dispute. See GridSouth at p. 62,004 (accepting a similar proposal regarding this function).

6. **Market Monitoring**.

In Order No. 2000, the Commission determined that market monitoring is needed to ensure that markets do not result in undue discrimination or provide the opportunity for the exercise of market power. At the same time, the Commission recognized the concerns that many have over market monitoring by RTOs. The Commission also acknowledged that different monitoring plans are likely to be appropriate for different RTOs. Order No. 2000, slip op. at 461-66.

The SeTrans model contemplates that the market monitoring function will be performed by a Market Monitoring Corporation ("Market Monitor") with an independent board of directors selected by the Stakeholders Advisory Committee. See GridFlorida, 94 FERC at pp. 62,362-65 (essentially accepting a proposal to use a separate, non-profit corporation to perform the market monitoring role). The System Administrator will contract with the Market Monitor for monitoring services consistent with the following objectives, authority, and obligations.

The primary objectives of the Market Monitor will be: (1) to objectively develop and report information regarding the structure and operations of the markets; (2) to propose actions regarding efficiency improvements, correction of design flaws, market rule violations, the identification of market power and other anti-competitive conduct; and (3) to conduct independent, objective monitoring consistent with safe and reliable operations and minimal interference with competition.

The Market Monitor will have the authority to monitor, investigate (on its own initiative or the request of any person or governmental agency) and report on: (1) market structure and operation, (2) compliance with market rules by all participants and the System Administrator, (3) market power and abuse, and (4) other anti-competitive practices and conduct. The Market Monitor will prepare and submit reports to the System Administrator, the Stakeholder Advisory Committee, interested state agencies, and the Commission.

The System Administrator will be required to provide to the Market Monitor, on request, all pertinent information in its possession. The Market Monitor may seek authority from the Commission to require market participants and the System Administrator to provide specific types of information to the Market Monitor. Appropriate confidentiality protections will apply to all information so provided to the Market Monitor.

In investigating market power abuses, rule violations and other anti-competitive conduct, the Market Monitor can investigate; seek mitigation; require explanations, justification and information; demand the cessation of inappropriate actions; submit FPA section 206 complaints to the Commission or file complaints with or inform other appropriate authorities; consider other enforcement mechanisms; request the System Administrator to submit proposed tariff changes for review 30 days in advance of filing with the Commission, if practicable; and recommend to the System Administrator changes in market rules. The independence of the Market Monitor should not be prejudiced by being subject to ADR review.

The Stakeholder Advisory Committee will review the budget of the Market Monitor and make suggestions prior to its submission to the System Administrator. The System Administrator will include the fee of the Market Monitor in its management charge, subject to Commission approval.

7. Planning and Expansion.

In Order No. 2000, the Commission determined that the RTO must have ultimate responsibility for both transmission planning and expansion within the region. The Commission also concluded that an RTO must encourage market-motivated operating and investment actions for preventing or allocating congestion, and must accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities. If it is unable to perform these functions at its formation, the RTO must file plans with the Commission with specified milestones to ensure that it meets the overall planning and expansion requirement no later than three years after initial operation. Order No. 2000, slip op. at 485-92.

The SeTrans model draws heavily from the GridFlorida planning model with appropriate modifications necessary to accommodate a multi-state region. See GridFlorida, 94 FERC at pp. 62,366-67 (generally accepting GridFlorida's Planning and Expansion proposal). The System Administrator of the RTO will be responsible for performing regional system studies, planning and arranging transmission expansions, additions and upgrades to enable the system to provide efficient, reliable and non-discriminatory transmission service. The System Administrator will have the responsibility to oversee and approve these plans. In general terms, the SeTrans model:

- Provides for the RTO to have ultimate planning authority.
- Encourages market motivated operating and investment actions for preventing or allocating congestion.
- Expects local area planning to be performed by transmission owners and coordinated with the RTO to ensure adequate load serving facilities are planned.
- Allows for enhanced facilities that do not adversely affect grid reliability.
- Utilizes a form of stakeholder planning committee(s) to ensure a forum for stakeholder input into the facilities, operation and reliability aspects of planning.

The Transco will also have authority to perform system studies and planning within the Transco footprint, subject to System Administrator review and approval. There is one significant exception to the Transco's planning authority. If a resulting improvement within the Transco's footprint would cause a change in flows greater than 5% on any constrained facility outside of the Transco's footprint, then the System Administrator will have primary planning responsibility. This limitation ensures that the System Administrator has the requisite authority to make planning and expansion decisions that materially affect the system, while reserving to the Transco those preliminary decisions that are truly within its sphere.

Transmission customers and transmission owners will have the opportunity to provide input into the planning process to ensure that adequate facilities are planned and that local issues (such as cost, right of way limitations and siting concerns) are properly considered. The System Administrator will establish and chair three joint planning committees: (1) Facilities Planning Committee; (2) Operations Planning Committee; and (3) Reliability Planning Committee. The composition of these Committees will consist of representatives from each transmission owner and all market participant classifications, to be determined through the stakeholder advisory process.

The Facilities Planning Committee will have an advisory role that recommends a jointly planned and prioritized list of projects to the System Administrator. The Facilities Planning Committee will have no approval authority; instead, the System Administrator will have approval authority for facilities that are to be included in its rates. The Facilities Planning Committee will be charged with the responsibility of recommending to the System Administrator implementation of a regional transmission expansion plan that fully serves traditional reliability needs and, at the same time, encourages market-motivated actions for preventing and relieving congestion in a way that establishes clear rights to transmission facilities and provides accurate price signals. The Facilities Planning Committee process will provide for meaningful opportunity for all interested parties to participate with the System Administrator, which is ultimately responsible for developing the regional plan and conducting the necessary studies and analysis in connection with such plans.

The Operations Planning Committee will provide a forum for transmission owners and market participants to have input into the operational planning process and be advised of potential operating problems in the next year. The Operations Planning Committee will have an advisory role to review the System Administrator's planned outage list. The Operations Planning Committee will have no approval responsibility. The System Administrator will have sole approval authority for planned outages as well as recommended solutions to extended planned outages.

The Reliability Planning Committee will provide a forum for transmission owners, stakeholders, and market participants to review and provide input to joint reliability planning activities (e.g., interregional studies).

After completion of this process, the System Administrator will communicate the desired improvements to the local transmission owner. Since it will probably be more expedient and less costly for the transmission owner in the area of the desired improvement to acquire necessary rights-of-way and to construct upgrades, that entity will have the option to develop the facilities. If that transmission owner is unable or unwilling to undertake the upgrades (which could be the case for regulatory or financial reasons), then the System Administrator could engage the Transco, another transmission owner or a third party merchant transmission provider to undertake the improvement. The building entity may be subject to the jurisdiction of various State regulatory agencies for such activities and, if so, will be required to obtain all necessary regulatory approvals. In this regard, the System Administrator should also accommodate any efforts that the States may undertake to create multi-state transmission arrangements.

With respect to market-motivated actions, the SeTrans model may include a form of pricing (e.g., LMP) that will provide economic signals concerning the need for transmission in specified locations. This pricing approach will also provide proper locational pricing signals for new generation siting.

8. **Interregional Coordination.**

The final function of an RTO is interregional coordination. The Commission determined that RTOs should coordinate their activities with other regions. The Commission specifically found that this is needed whether or not an RTO exists in those regions. Order No. 2000, slip op. at 494-97.

The coordination of activities among regions is an important element in maintaining a reliable and efficient transmission system. Utilities in the Southeast have worked together for many years to coordinate on reliability and other matters. The Georgia ITS is one very clear example of such an arrangement where transmission owners have worked closely to ensure reliability of the transmission system. Interconnection agreements between neighboring utilities are also indicative of the steps taken in the past to coordinate with other systems and to ensure greater reliability across a large area of the country. Furthermore, bulk power sales, including unit power sales, became extremely important in the Southeast beginning in the early 1980s and required that utilities address interface requirements on more than the historic reliability basis. The System Administrator will continue these types of efforts to enhance system reliability and to establish consistent rules governing the use of the grid.

The SeTrans model expects the System Administrator to continue this historical approach and to develop coordination agreements with all adjacent RTOs. Such negotiations should be given a high priority and should include the following concepts:

- Inter-RTO stakeholder conferences held several times a year to discuss issues affecting inter-regional transmission;
- A common set of protocols for TTC/ATC determinations to ensure consistent postings on interfaces;
- Common TLR and security coordination procedures;

- Coordination of congestion management methods including development of parallel path flow protocols;
- A standard generation interconnection procedure;
- Coordinated transmission planning and expansion; and
- Coordination of inter-regional transmission planning and other market implementation efforts between RTOs.

The SeTrans Sponsors commit to continue to work with other utilities and RTOs to coordinate these details where possible. In this regard, a memorandum of understanding between Southern Companies and TVA has been developed to facilitate this effort. With the express permission of TVA, a copy of this memorandum is being provided to the Commission as Attachment 6 of this Mediation Report.

While this MOU with TVA represents a significant accomplishment which should be applauded, it is also important to note that the MOU is essentially a coordination agreement that TVA acknowledges it would have entered into with either group of plan sponsors. In fact, Entergy is also a signatory to this agreement and Entergy is now a participating sponsor of the Collaborative Governance Model as a result of partnerships and coalitions formed during the course of this mediation.

III. MARKET PARTICIPANT RESPONSES TO THE MODELS

Market participant response to the mediation process was very positive. Approximately 200 market participants representing diverse stakeholder interests throughout the Southeast RTO footprint attended and fully engaged in this intense forty-five day mediation effort.

To enable us to "cluster" similarly situated interests for purposes of capturing market participant responses to the evolving models, and to assert "market based" mediation influence on the development of the models through this collaborative process, owner classification sectors were identified as follows: Investor Owned Utilities or "IOU"s, Cooperatives or "Coops", Municipals or "Munis", Federal entities such as SEPA and TVA, IPP/Generators, Power Marketers, Consumer/Industrials, and in an effort to facilitate their active involvement in the mediation process a separate sector was created for State Commissions. These eight sector groupings were used throughout the mediation process for such things as participating in "preference polling," smaller work group break out sessions and the like.

As previously mentioned, the plan sponsors were directed to submit to the market participants the first written draft of their "Straw Man" proposals on August 20th outlining the key aspects of their respective models with respect to each of the four RTO characteristics and eight core functions required by Order 2000. The market participants were then provided an opportunity to submit individual written comments to each of the Straw Man proposals. Individual responses were important to identify issues and concerns that may have been unique to a particular market participant; however, many market participants shared a number of common issues and concerns which were captured in a more powerful and effective way as a group. Accordingly, individual responses were submitted by sectors classification. Each "sector" self-selected three representatives and these sector representatives were tasked with the responsibility of collating the individual responses to create a "sector summary" for the purpose of capturing the market participant responses of their sector members for use in this Mediation Report. These same sector representatives also comprised the diverse "Stakeholder" workgroup, representing the individual members of each owner classification sector, for continued market participant involvement in mediation negotiations with the plan sponsors during the last two weeks of this collaborative effort. The Stakeholder workgroup proved to be an invaluable resource in facilitating continued communications with the full group of market participants and in ensuring that the market participants were fully represented in continued negotiations with the plan sponsors during these last two weeks. As a result, both models continued to evolve in significant and material ways in direct response to this market participant feedback right up to the very last day of the mediation.

This same procedural protocol was used to collate market participant responses to the final iterations of the models which were directed to be submitted on August 31st. The final iteration of the Sector Summaries were submitted to the mediation team on September 5, 2001 and form the basis for the market participant responses reflected in this Mediation Report. Accordingly, the market participant responses are submitted herein by RTO characteristics and core functions utilizing these same sector groups.

Characteristic 1 Independence and Governance

1. <u>IOUs</u>

The majority of participating investor-owned utilities (the IOU sector) support the Collaborative Governance Model, believing that it

- places all market issues, tariff design and rate decisions under the authority of an independent Transco board, and

- provides meaningful stakeholder input.

The majority of the IOU sector does not support the SeTrans Model, which creates a dual governance approach, where the System Administrator (SA) has its own board of directors, raising serious concerns about how decisions would in fact be made. However, one IOU does support the SeTrans model because it wants an independent operator that is the highest authority, is independent of all market participants, and does not own transmission assets. This IOU believes the SA in the SeTrans model fulfills these requirements, and has attracted the most support from non-jurisdictional participants. This IOU is concerned that an RTO that owns assets would naturally favor its own assets on issues such as transmission expansion, revenue allocation, market design and security coordination.

2. Coops

Issue: Reassignment of Functions and Replacement of Independent Market Administrator

The Cooperative Sector believes that the Independent Market Administrator (IMA) (proposed in the Collaborative Governance Model) must stay in place at least until there is an IPO for the Transco, and that any party (including the Transco) seeking to eliminate or reduce the role of the IMA at that time must file a complaint under FPA Section 206 and receive the Commission's authorization before such change can be implemented. The Cooperative Sector states that the IMA cannot work and be perceived as providing sufficient protection against the Transco's self-bias as a Transmission Owner if the IMA exists at the sufferance of the Transco. Commission scrutiny under Section 206 of the Federal Power Act, in addition to the Market Monitor review and notice periods proposed by the Grid Group, will ensure that if and when the IMA's responsibilities revert to the Transco, it is for the right reasons. (It should be noted that the sponsors of the Collaborative Governance Model have already responded to this concern by modifying the model accordingly.)

Issue: Selection of Independent System Administrator (ISA)

SeTrans' process for selecting the Independent System Administrator ("ISA") would have a slate of candidates selected entirely by the Stakeholder Advisory

Committee (SAC), without the TOs sitting as members,[35] which the Cooperatives support. However, the Cooperatives believe that, to be fully compliant with Order No. 2000, the TOs should have no decisional role in selecting the ISA, and only the SAC should determine the final slate of ISA candidates and select the ISA[36] Cooperatives also argue that the TOs should have no separate role in the termination of the ISA. If the TOs are not removed from this process, Cooperatives argue, they will exercise, or be perceived as exercising, undue influence over the ISA.

Issue: Elimination of Not-for-Profit Utility Representation on the Board of Directors

The Cooperative Sector notes that the Collaborative Governance Model does not meet the requirement in the *GridSouth* July 12, 2001 order that at least one member of the initial Board of the Transco and subsequent Boards be from the not-for-profit utility sector.[37] The Cooperative Sector submits that the Commission-mandated seat on the Board of Directors for individuals with not-for-profit utility experience should be reinstated.

Pricing

i. Full Revenue Requirement Recovery on Day 1

The Cooperative Sector has made clear that its members will not turn over control of their transmission facilities to the SPG RTO unless they are assured full cost recovery from Day 1, as they say IOUs are. As a compromise, the Cooperative Sector has

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[35] (SeTrans Model at 15.) The Cooperatives are giving the SeTrans proponents the benefit of the doubt as to their language at page 15, as that language could be read to allow the TOs to add candidates to the final slate selected by the SAC. They are assuming that this was poor draftsmanship, rather than an attempt to empower TOs to nominate candidates through the "back door."

[36] In this context, the Cooperative Sector would not object to the TOs having voting representation on the SAC, like other stakeholder groups.

[37] In that order, the GridSouth applicants were directed to modify section 6.1(b) of the LLC Agreement such that "at least one member of the Board will have experience in the non-profit sector. . ." The Commission determined that if GridSouth were to downsize its Board, it could not eliminate the seat for a Board member with not-for-profit utility experience. *GridSouth Transco, LLC,* 96 FERC ¶ 61,067 at 61,305 (2001).

proposed that if the cost shift impact (*i.e.*, the impact on retail rates) of including transmission dependent utility ("TDU") transmission facilities in the RTO rates is greater than 3%,[38] then the recovery could be phased in over two years.[39]

The Cooperative Sector says that the SeTrans Model recognizes the propriety of giving non-jurisdictional TOs full and immediate rate recognition for their facilities. In contrast, the Collaborative Governance Model, which the Cooperatives claim is discriminatory, would phase in the revenue requirements of certain not-for-profit entities (namely, transmission-dependent utilities, or TDUs) over five years. The Sector argues that the phase-in is contrary to the acknowledged need to include non-jurisdictional utilities in the RTO in the Southeast. The Cooperative Sector argues that this position is justified based on its assertions that the cost shift mitigation impact of full cost recovery on Day 1 would be less than half of one percent.[40]

Pricing by Region

The Cooperative Sector opposes the Collaborative Governance Model's new pricing concepts, i.e., that pricing be by region, that there be a Regional Charge to recover the cost of "new Non-Bulk Transmission Facilities" and that each region be free to determine "which facilities are under the control of the SPG RTO and included in rates" (Pricing Protocol, Attachment 2, p. 2). The Sector argues that these represent regional balkanization and bulk versus non-bulk transmission concepts, which it calls "significant steps away from the unitary approach envisioned by the Commission in Order No. 2000." The Cooperative Sector believes that the Commission wants regional

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[38] The Cooperative Sector bases its 3% standard on Chairman Wood's partial dissent in *PJM Interconnection, L.L.C. and Allegheny Power*, 96 FERC ¶ 61,060 (July 12, 2001) ("total retail customer bill shifts greater than 3 percent may warrant use of a transitional device such as continuation of license plate rates, but any shift smaller than that would not.").

[39] The Cooperative Sector wants any phase-in to also consider cost shifting caused by congestion management; the Cooperative Sector says neither of the Plan Applicants addressed this.

[40] The Cooperative Sector claims that in the *GridFlorida* proceeding, the unrebutted numbers showed that inclusion in rates of the revenue requirements of the TDU facilities on Day 1 in Florida would increase retail rates by 0.3%. The East Texas Cooperatives estimate that including their facilities in rates on Day 1 would increase retail rates by about 0.4%.

RTOs with system-wide rates for the use of all transmission facilities within the RTO (and argues that the facilities properly within the RTO's control should be identified by a uniform “bright line” standard, i.e., by a defined voltage level).[41]

Planning

SeTrans' proposal lacks a fully developed Planning Protocol. The majority of the Cooperative Sector is concerned that TOs may be able to retain more control of the planning function under the SeTrans model than may be appropriate under Order No. 2000.[42] Additionally, TOs (and ITCs, if permitted) should execute the *pro forma* agreements (like the GridFlorida Participating Owner Management Agreement, or POMA) without modifications, so that planning and other important RTO functions may not revert to the incumbent TOs.[43]

Splitting of RTO Functions

The Cooperative Sector notes that both models would, to some degree, split RTO functions among more than one entity (e.g., the Transco, the IMA, and one or more ITCs under the Collaborative Governance Model, and the ISA and the TO's in the SeTrans model). The Cooperatives argue this is contrary to Order No. 2000 and will undermine the efficiency of the RTO, detract from the RTO’s independence, and create opportunities for competitive advantages and discrimination. Those Cooperatives that support divestiture also believe that the dispersion of RTO functions among entities may discourage TOs from divesting their assets to the Transco and thus frustrate the ultimate objectives of (i) separating generation from transmission and (ii) encouraging new transmission projects. As to the SeTrans model, divestiture to the Transco appears even

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[41] Citing *Cf. Entergy, Inc.*, 85 FERC ¶ 61,163 at 61,144 (1998) (affirming Initial Decision on whether rates for network integration service should be determined on a single-system or sub-functionalized basis); 91 FERC ¶ 61,153 (2000), Order Granting Clarification and Denying Rehearing.

[42] Citing *Carolina Power & Light Co., et al.*, 95 FERC ¶ 61,282, at 61,995-96 (2001) (“We expect that transmission owners will identify their transmission needs due to growth in native load or other changing circumstances, and submit those needs to GridSouth.... However, it is GridSouth that will make the determination as to what transmission investment satisfies the need of the affected Transmission Owner....”)

[43] Clearly defined exceptions to the TOA/POMA should be permitted to accommodate inclusion of facilities in the RTO’s scope, *e.g.*, tax issues.

more remote. Cooperatives also argue that the delegation and sub-delegation of authority between and among the various entities under the SeTrans model will, for all practical purposes, replicate the decentralized situation that exists today.[44] They argue that ITC(s), if permitted, should not be treated any differently from other Participating TOs, should not be assigned any RTO functionality, and should be required to sign an ITC-Transco agreement modeled on the GridFlorida POMA. Cooperatives argue that ITC proponents have not explained why they cannot achieve the same goal through divestiture to the Transco.

Loads That Must Be under the RTO's OATT

Cooperatives argue that the RTO must be the sole transmission provider of all transmission service rendered across the facilities under its control, fully subject to the rates, terms and conditions of the RTO's OATT, and that neither model meets this test. They note that the ISA under the SeTrans model "will be the sole provider of *unbundled* transmission service over the facilities that it operates" (SeTrans Model, p. 37; emphasis added,) and express their concern that other language (that "the SeTrans Sponsors expect that all load would be under the OATT (with appropriate treatment for grandfathered agreements)" and that "[i]n this regard, the SeTrans Sponsors anticipate that they would take network transmission service from the RTO for their retail and bundled wholesale customers" (*Id*.)) is not an unequivocal commitment to put all loads under the RTO's OATT (except where it might violate state law or imperil the not-for-profit tax status of the affected TO). The Collaborative Governance Model places all loads under the OATT as to terms and conditions, but the rates for transmission for bundled retail sales in each TO's area would be set by the relevant state public service commission, and each region (which in some cases would be a single entity, *e.g.*, Entergy) is free to determine "which facilities are under the control of the SPG RTO and included in rates." Pricing Protocol (Attachment 2, p. 2). The Cooperative Sector urges that all loads using the RTO

[44] Two cooperatives support delegating responsibilities like local area planning to the ITC. In their experience, the incumbent TOs, when engaged in joint transmission planning of load-serving transmission lines and substations in areas where both the TOs and the Cooperatives have retail customers, have shown favoritism towards the TOs' own projects. (The Cooperative majority shares this concern.) These Cooperatives, unlike the majority of the Cooperative Sector, believe that they will obtain unbiased planning analysis and decisionmaking, based on the merits, from an ITC, because of its independent professional staff, management, and board.

transmission facilities must do so under the RTO OATT's rates, terms, and conditions,[45] and that to do otherwise would upset the competitive equilibrium at the retail level and permit continued discriminatory treatment.

3. Munis

Every participating Municipal prefers SeTrans' governance, with an Independent System Administrator having ultimate authority over a single Transco, to the Collaborative Governance Model, in which a Transco delegates certain functions to an IMA for five years, subject to earlier retrieval if exigent circumstances occur, and multiple ITCs are assigned special roles.

The Munis prefer SeTrans' process for selecting the ISA. The Collaborative Governance Model gives the TOs the critical role of nominating the slate of candidates and another bite of the apple through their votes on the SAC. The Munis believe the nominating role is more controlling than the selection role; they recommend a unicameral process like the Collaborative Governance Model's Transco board selection process for ISA selection.

The Munis also feel that the Collaborative Governance Model gives the market-participant-dominated Advisory Committee control over Transco Board succession, at least until the IPO occurs, and violates Order No. 2000's independence in that it lets market participant TOs control line ratings in ATC calculations.

This sector believes that SeTrans has provided a structural solution to the problem of a Transco favoring its transmission facilities over (other) facilities it manages. In contrast, they submit that the Collaborative Governance Model IMA's functions are too narrow and can be too easily repossessed by the Transco. In particular, they argue, the IMA, not the Transco, should be responsible for designing markets because 1) design and operation responsibilities should be united, 2) market design will be most critical during the pre-IPO period, when the Transco will be governed by a self-perpetuating board with no independent constituency, 3) the provision that the Transco may not re-posses Administrator functions without Commission approval under either section 203 or 205 of the Federal Power Act offers limited comfort; the Transco should be required to show

[45] By this request, the Cooperative Sector is not urging the unilateral abrogation of existing contracts. *See GridFlorida*, 94 FERC ¶ 61,363 (2001), citing Order No. 2000 at 31,204.

that the recapture of Administrator functions will enhance RTO functionality, 4) the Board's ability to remove the IMA intra-term for exigent circumstances threatens to gut the Administrator's functionality by other means, and 5) since the Transco's ownership area will probably be much smaller than the RTO, especially at first, the Transco will be too geographically parochial to properly have market design responsibility for the entire region.

The Munis doubt that the Transco under either model will yield independent transmission ownership, especially if, as anticipated, state commissions are reluctant to permit divestiture. They argue that the Transco's ownership area will likely be a few disconnected patches, stitched together with more extensive areas in which the TOs retain ownership.

The Collaborative Governance Model insists that virtually all Transco Board members have investor-owned corporate experience, but retreats from a prior commitment to include a Board seat for someone with public power experience, as ordered in GridSouth. This sector urges that a Board seat should be reserved for an independent person with substantial experience working on behalf of public power, but the Collaborative Governance Model only reserves a nomination slot for a candidate experienced in "working with" public power, which Munis fear could be interpreted to include someone who has worked against public power on behalf of an IOU.

Several Munis oppose the Collaborative Governance Model 's 3-way split of planning authority among the IMA, Transco, and ITCs. In particular they object that an ITC that owns no facilities, but merely operates them under a TOA, could receive special powers in planning and studying service requests that are not warranted (the ITC is not the entity that performs grid expansion). Munis do not believe that this proposal helps public power entities create a non-profit company, and calls it "a pointless additional layer of delegated authority that can only undercut the RTO's functionality."

Munis argue that the Collaborative Governance Model "singles out TDUs for confiscatory rate treatment (even where the 'cost-shifting' impact of equal rate treatment would be de minimus)" and thereby discourages public power participation in the RTO.

Collaborative process

The Munis believe that the SeTrans model promises better pre-operational governance and collaboration.; the ISA is brought in early and public power participates in the collaboration. They argue that the Collaborative Governance Model would have Applicants control the drafts and adopt others' suggestions only when they agree.

Stakeholder Advisory Committee (SAC)

Munis argue that the Collaborative Governance Model dilutes their influence on the SAC by combining them with federal and state-owned systems; municipals therefore recommend creating a new category. Munis support SeTrans' neutral determination of the revenue requirements of non-jurisdictional transmission owners, by the ISA and dispute resolution, without directly submitting the non-jurisdictional utilities like Munis.

TOAs and POMAs

Munis believe SeTrans' Administrator-Owner TOA will better accommodate the non-jurisdictional transmission owners than the Collaborative Governance Model's POMA, because the TOA includes bilateral architecture that allows variations which meet individual systems' legal needs without affecting RTO functioning.

Independence of Grids' Transco from passive owners

Munis feel that the Collaborative Governance Model's Transco is not clearly independent from its passive owners; passive voting rights over Transco corporate actions should be clearly transcribed and no broader than the Commission allowed in GridFlorida.

4. Fed/State (Southeast Power Administration and TVA)
TVA

TVA has elected not to file individual responses to the final iterations of the two models; however, a memorandum of understanding between Southern Companies, Entergy, and TVA has been developed to facilitate this RTO effort. With the express permission of TVA, a copy of this memorandum is being provided to the Commission as Attachment 6 of this Mediation Report. While this MOU with TVA represents a significant accomplishment which should be applauded, it is also important to note that the MOU is essentially a coordination agreement that TVA acknowledges it would have entered into with either group of plan sponsors. Further, as previously indicated, TVPPA has indicated that while they would have preferred the creation of a not-for-profit Southeast RTO structure, regardless of the RTO structure TVPPA supports TVA's proposal to enter into coordination agreements that could eliminate pancaked transmission rates, achieve a coordinated OASIS for reserving transmission services, develop a framework for coordinated transmission planning and expansion, and result in further similar benefits, that would facilitate the creation of a seamless transmission market within the region.

SEPA

SEPA has elected to submit responses to both of the mediation models on certain key issues as follows.

Encouraging participation by non-jurisdictional TOs/public power

SEPA very strongly believes that it is vitally important that non-jurisdictional public power entities be participants in the region-wide RTO. Without the public power utilities (PPUs), the Southeast RTO will not address the needs of SEPA and the region.[46]

SEPA believes that an Independent System Administrator that does not own transmission or generation assets, as proposed by SeTrans model, appeals to the TO PPUs' concern that their assets will be treated equally by the RTO with the assets of the TO IOUs.

Splitting of RTO Functions

SEPA contends that the functions that should be included in the System Administrator include: (1) Administration of all markets administered by the RTO; (2) Exercise of operational authority over the system; (3) Administration of the OASIS and calculation of TTCs and ATCs; (4) Processing and approval of requests for transmission service and interconnection; (5) Assumption of the Security Coordinator function; (6) Tariff administration and rate design; (7) Transmission planning; and (8) Market Design. The SeTrans model has a System Administrator, which has these eight responsibilities. The Collaborative Governance Model gives functions 6, 7, and 8, as well as performance of system impact and other studies for transmission and interconnection service requests, to the Transco.

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[46] SEPA has transmission arrangements with five of the eight Plan Participants that are IOUs, and with four of the seven Plan Participants that are PPUs. Also, SEPA has transmission arrangements with two transmission-owning public power utilities (TO PPUs) that have not become Plan Participants. SEPA believes that all of these TO PPUs should join the Southeastern RTO, as finally configured, and notes that the SeTrans model has TO PPUs that are Plan Participants.

SEPA is also concerned that the authorities given to a particular Independent Transmission Company (ITC) may place it in a superior position compared with other transmission owners. The SeTrans model allows the participation of ITCs, but places the control in the System Administrator's area ; the ITC will be treated as any other TO. The Collaborative Governance Model would give the ITCs more autonomy than SEPA desires.

Stakeholder Advisory Committee (SAC)

SEPA believes SeTrans' proposal recognizes the uniqueness of Federally-owned generation and transmission facilities by allowing a representative of the Federal sector to sit on its Advisory Committee. The Collaborative Governance Model does not, nor does it provide for equal participation by PPUs, which would either have to compete with IOU generation/distribution companies for a seat on the SAC, or represent the wholesaler sector, which would limit their participation.

Selection of Independent System Administrator (ISA)

SEPA prefers the SeTrans model on this issue as well, under which the Stakeholder Advisory Committee, with the Transmission Owners not voting, selects a list of candidates, and the Transmission Owners select the System Administrator from the list. In contrast, the Collaborative Governance Model proposes that the TOs select the qualified entities and the Advisory Committee selects one of those entities, and future IMAs are selected by the Transco with the approval of the Advisory Committee.

TOAs and POMAs

SEPA also notes that the SeTrans model clearly defined that the Transmission Operating Agreement for all transmission owners will be *pro forma*.

Cost shifting/pricing

SEPA asserts that the SeTrans model has more clearly defined the cost shift issues. The prior proposal created a misunderstanding regarding full revenue requirement recovery on day one and the need for cost shift mitigation. The present proposal limits cost shift mitigation to the elimination of rate pancaking, and the transition from license plate to postage stamp rate, which has increased SEPA's support of the model.

5. <u>IPPs/generators</u>

The IPP sector supports the Collaborative Governance Model, arguing that it is the only one whose governance structure fulfills Order No. 2000's specific independence criteria while also creating an RTO model that will ensure efficient system operations, timely and appropriate expansion of the transmission grid, and promote transparent, efficient, competitive bulk power markets. The Sector asserts that the SPG model places all market issues, tariff design and rate decisions under the authority of the independent Transco board and provides for appropriate stakeholder representation and meaningful stakeholder input with respect to board selection, IMA selection, and access to the board and RTO staff.

Selection of ISA/ISA compensation

IPPs object that the SeTrans model lets transmission owners (TOs) directly control the selection of the "independent" system administrator (SA) by directly controlling the hiring/firing of the SA and, through their authority over the SA's contract (and the SA's compensation), which allows at least indirect control over all of the SA's actions post-contract.[47] Consequently, the TOs will be able to exert undue influence over the SA.

TOAs and POMAs

In addition, while the SeTrans proposal refers to starting with a *pro-forma* TOA, it contemplates the negotiation of customized terms with each transmission owner under terms which have not been defined, let alone reviewed, thereby creating the likelihood that RTO authorities will be delegated back to individual transmission owners.

Dual governance under SeTrans

The SeTrans proposal also creates a dual governance approach, where the SA has its own board of directors, raising serious concerns about how decisions would in fact be made. The Commission and IPPs' experience with dueling governance boards (*e.g.*,

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47 SeTrans proposes to change the SA selection process to eliminate the right of the Transmission Owners ("TOs") on the Stakeholder Advisory Committee to vote on the selection of the slate of SA candidates. However, because the TOs will vote to select the SA and will be the sole counterparties to the SA contract, the SA's independence will not be assured. Therefore, they argue, this change does not represent movement on the part of SeTrans to address the market participants' concerns.

NEPOOL) has proven that this model can paralyze, rather than advance, the market process. IPPS believe the governance flaws in the SeTrans proposal would only serve to protect the status quo rather than promote better markets.

Level of detail

IPPs argue that the SeTrans proposal lacks sufficient detail and/or is simply unclear in most critical areas including, but not limited to, the manner by which stakeholder advice is considered and whether the TOs will have a superior role in RTO decisions and filings, particularly prior to their hiring the SA. Since the SA Board would be the section 205 authority, presumably the TOs contemplate their having that authority prior to their hiring the SA, on their schedule.

Splitting of functions/further proceedings/collaborative process/timely start-up

Some IPP sector representatives, while expressing strong support for the Collaborative Governance Model, are concerned about the delineation of functions between the Transco, the IMA and any ITCs. Unfortunately, they acknowledge, the precise separation of functions and the consequences, if any, of such a separation on the development of a competitive market is difficult to address without some practical experience – and certainly not without further detail – and should thus be the subject of a continued stakeholder process.[48] But, even in the absence of this detail, the Collaborative Governance Model clearly creates the best opportunity for the timely development of a viable, stand-alone transmission business(es) to serve the needs of all market participants in the Southeast region.

6. <u>Marketers</u>

The Marketer Sector strongly supports the Collaborative Governance Model with respect to Independence. Only one participant in the Marketer Sector initially expressed support for the SeTrans model (and that participant now partially accepts the Collaborative Governance Model). However, as noted below, some Marketers express concerns with respect to the Independence of the current model and have proposed some specific modifications to address these concerns as follows.

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[48] SeTrans proposes to transfer some RTO functions from the SA to the Transco. However, because such transfer of functions would require the approval of the SA, it is unlikely that the proposed SeTrans Transco would be able to attract investors.

Divestiture/SAC/Selection of IMA

Most of the Marketer Sector believes that divestiture of transmission assets into a Transco with an independent Board and strong Stakeholder Advisory Committee (SAC) is key to ensuring non-discriminatory access to the transmission system and comparable treatment for all market participants. Most of the Marketer Sector believes that the Collaborative Governance Model is best structured to achieve this goal.[49] Another advantage to this model is that the SAC selects the Independent Market Administrator (IMA).

Splitting of functions/5-year term of IMA/ITC as a not-for-profit/SAC composition

The most recent iteration of the Collaborative Governance Model has changed the process for the Transco to reclaim functions from the IMA to require that the Transco make a filing under Section 203 and/or 205 of the Federal Power Act, whichever is applicable to the change being made. In addition, they have clarified that an Independent Transmission Company (ITC) can be a non-profit company that public power entities (or any other transmission owner) can create, and that such an entity can either own divested transmission facilities or exercise operational authority over transmission facilities pursuant to transmission operating agreements (TOAs). Finally, they have changed the SAC composition to make sure that there is at least one representative from the end-user sector. Most Marketers believe that these modifications strengthen the model. Notwithstanding, one Marketer continues to express concern with the Collaborative Governance Model for the following reasons:

> 1. In Order No. 2000 the Commission determined that the RTO must have the operational authority for all transmission facilities under its control and also must be the security coordinator for its region. Under the Transco is the SPG RTO and, yet, the operational and security coordinator authority is vested in the IMA. Based on Order No. 2000, it appears that the IMA should be the RTO.
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> 2. The IMA is not completely independent from Transco (asset ownership) control as currently structured under the Grid model. Some examples include: (I) the IMA candidates are selected by the Transco; (ii) the Transco is authorized to delegate via contract "certain operating responsibilities" to the IMA; (iii) the Transco has the authority to reclaim functions from the IMA after five years or

[49] Some modifications may need to be added pre-divestiture to the Transco to the extent that the independent Transco has certain functions and responsibilities.

sooner in the event of exigent circumstances; and (iv) the Independent Board is selected by a Board Selection Committee that is comprised of 7 transmission-owning members and 6 members from the non-transmission owning sectors, thereby ensuring dominance by the transmission owners.

3. While the SAC is authorized to provide advice to the Transco and the IMA, the SAC is weighted in favor of the IOU sector, which provides IOU sector voting dominance.

In order to insure compliance with Order No. 2000, and establish a truly independent and non-discriminatory RTO with no commercial interest in market outcomes, some entities within the Marketer Sector recommend specific modifications that they believe will strengthen the Collaborative Governance Model, including:

-Augment the IMA with its own independent Board of Directors,

-Strengthen the IMA by transferring all RTO functions except Rate Design to the IMA

- Modify the Board Selection Committee by replacing one member of the divesting IOU sector and adding a representative to one of the non-transmission owning sectors,

-Modify the SAC by replacing one representative from the transmission-owning sector and adding one additional representative to one of the non- transmission owning sectors.

7. <u>Consumers/End users</u>

Consumers believe that both models, SeTrans and Collaborative Governance Model contain desirable and undesirable features.

Composition of Stakeholder Advisory Committee/collaborative process

All sector members are concerned with establishing a strong Stakeholder Advisory Committee ("SAC") and believe industrial end users are entitled to a separate slot on the SAC. The SeTrans Model would apparently make industrial customers, that represent approximately a third of the total load in the Southeast, a stand-alone sector. The Collaborative Governance Model would force all end-users into a sector that also includes governmental entities and non-governmental organizations (NGOs) such as environmental groups – entities with little or no affinity with large corporate energy buyers.

However, Consumers assert that a collaborative process has been controlled by some of the current plan proponents, with less than satisfactory results, and argue that neither model currently affords them the recognition they deserve. They believe that they should be classified as an independent sector with its own voice because neither some other sector nor a shared sector can adequately represent their interests. They argue that Consumers must be granted representation in the form of a separate sector for purposes of: (I) Board selection, (ii) selection of the Market Monitor, (iii) selection of the Administrator (IMA/SA), and (iv) the entire "collaborative process."

Viability of Transco on Top

The Collaborative Governance Model is premised on the divestiture of significant portions of the transmission assets in ten states. Certainly the viability of the Transco is in doubt if the Transco footprint does not include -- at a minimum -- all the major congestion points in the Southeast. Yet, this sector notes concern that there is apparently little interest among state commissions to allow such divestiture. Absent a stronger public commitment from the states to allow divestiture into the Transco, Industrial Consumers strongly question the merits of going forward with the Collaborative Governance Model. Industrial Consumers recommend that the Model "take the Transco off the top" until the state commissions have made such a commitment.

Splitting of RTO Functions

Consumers believe the responsibilities of the Independent Market Administrator under the Collaborative Governance Model should include all the functions of the SeTrans System Administrator until a viable Transco has been formed, then the Transco may share certain functions consistent with Order 2000.

Consumers observe further that the Collaborative Governance Model continues to allow a significant role for ITCs, i.e., the option for ITCs to share functions (including system impact studies). They believe that centralization of RTO functions is very important, and the reassignment of any functions to the Transco after five years should not be allowed.

Selection of Independent System Administrator (ISA) or Independent Market Administrator(IMA)

The SAC must play a significant and meaningful role in selection of all of the following: the Board, Market Monitor, and Administrator (IMA/SA). Consumers prefer SeTrans' process for selecting the System Administrator to the Collaborative Governance Model process for the selection of its IMA because under the SeTrans proposal, the SAC can veto any candidate; under the Collaborative Governance Model, the SAC can approve only candidates that were previously approved by the TOs. The SAC in the SeTrans process has more influence over the ultimate choice of the SA than the SAC has over the ultimate choice of the IMA in the Collaborative Governance Model process.

Selection of SA's Independent Board

Industrial Consumers support the manner in which the independent board is established by the third-party System Administrator. Under the SeTrans proposal, all candidates for the System Administrator role must be approved by the Stakeholder Advisory Committee, including approval of the SA's independent board. This is a strength absent from the Collaborative Governance Model.

Compensation of independent administrator

Industrial Consumers support the incentive-driven, performance-based method of compensation for the SeTrans' System Administrator.

8. State Commissions

While several of the state commissions did participate in this mediation process at various levels of involvement as discussed more fully herein below, only one elected to submit comments on the proposals in this mediation proceeding and these comments were submitted confidentially, under the provisions of Commission Rule 606, 18 C.F.R. § 385.606. Because the comments can not be shared here without revealing the identity of the participant, they will not be included in this Report. However, in accordance with Rule 606, the comments have been shared with the plan sponsors and the market participants engaged in this mediation effort.

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C2. Scope and Regional Configuration

1. <u>IOUs</u>

Participation by non-jurisdictional entities/public power

Both the Collaborative Governance Model and SeTrans model adopt the same geographic scope and configuration as their objective. The IOU sector believes the scope and configuration issue boils down to which model will better attract participation by non-jurisdictional participants. The majority of the IOU participants support the Collaborative Governance Model on the grounds that it offers viable options for participation by non-jurisdictional entities. One IOU disagreed, believing that SeTrans' will be able to better draw in non-jurisdictional participants and achieve that scope and configuration.

Pricing/revenue recovery

Another IOU is concerned that provisions in each model affecting its ability to recover its revenue requirement might affect the ultimate scope of the RTO.

2. <u>Coops</u>

No specific comments on scope/regional configuration.

3. <u>Munis</u>

Participation by non-jurisdictional entities/public power

Every voting Muni believes SeTrans' proposal will produce a broad, contiguous RTO because it is better designed to bring in public power.

Entergy and SPP a natural market

One muni objects to both models on the basis that Entergy and the rest of SPP form a natural market that should stay within one RTO.

4. <u>Fed/State (SEPA)</u>

Participation by non-jurisdictional entities/public power

The scope of the RTO, as established by the mediation order, is one RTO in the entire Southeast. SEPA believes that the Southeastern RTO needs full participation by all TOs, and the scope will be too small if organizations such as TVA, Santee Cooper, JEA, SMEPA, GTC, MEAG, Tallahassee, Dalton, and AEC, are not involved. The SeTrans model has many of the TO PPUs as participants and has a “seams” agreement with TVA. SEPA hopes TVA will join the SeTrans group. The Collaborative Governance Model appears to have no support from TO PPUs at this time.

5. IPPs/generators

Participation by non-jurisdictional entities/public power

While both the Collaborative Governance Model and SeTrans model adopt the same geographic footprint and configuration as their objective, the IPP sector supports the Collaborative Governance Model as most likely to achieve a scope consistent with that footprint. Many IPPs note that this model was supported by all but one (*e.g.*, Southern) of the jurisdictional transmission owners and nearly unanimously supported by IPPs and Marketers. Many indicate that this model offers viable options for participation by non-jurisdictional entities and disagree with SeTrans’ claim that its proposal ultimately will be able to better achieve that scope and configuration.

Physical rights/balanced schedules/control areas/load under RTO control

This sector believes that the SeTrans physical rights-based congestion management preserves what they term its "balkanized" control area authority within the RTO footprint,[50] and its balanced schedule requirements, would compromise the effective scope of the RTO.[51] They refer to support for the SeTrans proposal as support for

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[50] SeTrans proposes to restrict economic scheduling between local control areas to periods in advance of real time and to maintain real time balancing authority at the local control area level. Beyond the conflict of interest inherent in having their staff, an affiliate of a market participant, have access to confidential data of other market participants and to unilaterally exercise control over real time market outcomes, such an approach requires contract path scheduling within the RTO and associated requirements for internal point-to-point transmission reservations, NERC tagging and other procedures that further would impede economic system operation.

[51] Furthermore, in addition to the reasons previously mentioned, preserving

(continued...)

maintaining the status quo. They argue that SeTrans' model preserves the existing control area boundaries while Collaborative Governance Model is willing to transition away from individual control areas, with the result that the Collaborative Governance Model proposal will offer far greater scope to the RTO. Also, they assert that the Collaborative Governance Model model is superior in scope and configuration to the SeTrans model[52] because all eligible customer load would be placed under the RTO tariff[53] -- an essential element of any successful RTO.

6. Marketers

Viability of Transco on top

The Marketer Sector generally prefers the Collaborative Governance Model because IOUs over a large scope are more likely to structurally separate through divestiture.

Participation by non-jurisdictional entities/public power

One marketer finds either model acceptable as long as it encompasses substantially all types of entities in the Southeast.

7. Consumers/End users

Participation by non-jurisdictional entities/public power

Sector members believe that RTOs should be established with the largest possible

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(...continued)
existing control areas also would frustrate the development of a competitive market because the regulation needs of the RTO required to manage each local control area's specific Area Control Error (ACE) and to sustain inter-LCA interchange schedules would likely be higher than that needed to manage an RTO-wide ACE.

[52] One market participant notes that the current lack of support by non-jurisdictionals and the alleged ability of non-jurisdictionals to leave the RTO may reduce its scope.

[53] While SeTrans purports to include all load under the RTO tariff, additional modifying language provides for grandfathering exceptions associated with ITS which raises the concern that this shift may be more virtual than real.

"footprint." The SeTrans model will apparently guarantee that more non-divesting and non-jurisdictional TOs will participate in the RTO and therefore ensure adequate scope and configuration. Clearly, the SeTrans proposal is more accommodating to non-divesting and non-jurisdictional TOs by the fact that many of these entities are already SeTrans Model plan applicants.

C3. Operational Authority

1. <u>IOUs</u>

Level of detail

Generally, the IOU sector favored the Collaborative Governance Model. The SeTrans report contemplates further collaborative development of *pro forma* documents, but details are lacking.

2. <u>Coops</u>

Coops did not address Operational Authority.

3. <u>Munis</u>

No Muni sees a major difference between the models, and several abstained for this reason. Several Munis supported SeTrans for reasons such as the long-term unified Administrator will better support operational efficiency, the Muni supports balanced scheduling requirements, and SeTrans will not own facilities that could be favored. Two Munis prefer the Collaborative Governance Model because it appears more open to considering control area consolidation.

4. <u>Fed/State</u>

Balanced schedules

SEPA understands that the congestion management financial model does not require balanced schedules. SEPA is very concerned with transmission users not being required to have balanced schedules, believes that both models at this time are expected to have balanced schedules, and would support having balanced schedules, even if they are not required.

5. <u>IPPs/generators</u>

Control areas/balancing market

Generally, the IPP Sector favored the Collaborative Governance Model because the IMA would be clearly in charge of directing the actions implemented by local control center[54] operations staff. The SeTrans proposal lacked clear definition of the actual split of authority between the SA and local control areas, although it implied a delegation of real time balancing functions to the existing control area operators. The IPP Sector notes that SeTrans proponents have not adequately responded to the FERC's concerns in its July 12, 2001 GridSouth order with respect to a local control area balancing authority dueling with RTO real time redispatch authority.[55]

IPPs believe that, in response to market stakeholder feedback, the Collaborative Governance Model produced a workable, substantive approach that is consistent with Order 2000 and which, unlike the SeTrans proposal, does not appear to be intended principally to maintain the status quo on operational issues. Indeed, many IPP sector representatives noted that the whole purpose of the RTO would be frustrated by this trend and that the RTO should strive to improve upon the Order Nos. 888 and 2000 constructs.

Splitting of functions/control areas

While generally supporting the Collaborative Governance Model, some generators were concerned that the exact authority between the Transco, IMA, and ITC needs further clarification and development to avoid potential problems with multiple layers of control. Most generators liked the Collaborative Governance Model objective of collapsing the

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[54] IPPs argue that the Collaborative Governance Model's use of the term "local control area" is somewhat of a misnomer since in most circumstances the operations staff at the local control center is merely implementing IMA directed dispatch instructions. That function is more aptly referred to as "local control center" function to avoid confusion. The authority of the IMA over operations must be confirmed. *But cf.* Collaborative Governance Model does suggest that ITCs and control area operators might retain some operational authority.

[55] Despite two years time and opportunity for meaningful stakeholder dialogue, SeTrans has deferred submission of sufficient detail in favor of dealing with what it characterizes as "Day 2" market design issues in a subsequent, still to-be-defined process where they and other TOs would assume control (since there would be no SA in place at that point).

multiple control area into a single control areas with a workable transition that might utilize the communications and control infrastructures at those control centers under an RTO dispatch direction.[56]

6. Marketers

Balanced schedules

The Marketer Sector generally prefers the Collaborative Governance Model for Operational Authority, although one marketer prefers the SeTrans model, unless the Marketer Sector recommendations, particularly regarding governance, are implemented in the Collaborative Governance Model.[57]

Control areas

Marketers fully support the Collaborative Governance Model proposal to consider collapsing the control areas in order to establish a clear hierarchical separation to the RTO; the RTO must be independent and have the authority for control. In this model, Control area operators will continue to physically control the system, but they will do so pursuant to operating procedures approved by the IMA. While the Collaborative Governance Model RTO Operating Protocol Summary (Op. Prot.) generally provides many of the details of this separation, several modifications are needed to fully eliminate

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[56] The staffing at local control centers must be independent of market participants who today operate those control areas. Control center operators in the normal course of business would have access to the competitive information regarding other market participants, and these operators plainly would derive a competitive advantage if allowed to monitor their competitors' generation. Hence, these issues should be addressed further through the stakeholder process.

[57] Marketers oppose the SeTrans model's requirement for day-ahead balanced schedules and financial penalty for imbalances. They argue there is no empirical evidence that such requirements improve the reliability of the transmission grid, while the PJM market design that allows unbalanced schedules is the only market that has reduced the number of TLR events in order to maintain reliability.

the discriminatory aspects of control areas.[58]

Real-time markets/financial rights

Finally, Marketers are concerned that the RTO should not favor any one participant, or a particular generation/transmission solution, to reliably operate the transmission system in real time. The adoption of the an LMP/financial rights model (with the transparent real time spot energy market where generators get dispatched and paid based on their offer curve) greatly assists in eliminating such discrimination.

7. <u>Consumers/End users</u>

Splitting of functions

One sector member opines that operational authority will more likely be cleaner under the SeTrans proposal because of the greater centralization of functional authorities under the System Administrator. The separation of functions between the Collaborative Governance Model's Transco and IMA (and potentially, ITCs) may create potential problems akin to the adage "too many cooks in the kitchen." Another Consumer submits that "the proposed allocation of authority to the IMA is appropriate."

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58 First, the RTO IMA "approves all inter-control area schedules" and the Control Area Operators "perform control area validation of all tags and schedules." (Op. Prot. at 11 and 12). Clearly, the RTO IMA must have the final authority for approval of all tags and schedules in order to avoid situations in which a control area operator could deny a tag of an IPP located within its control area in a discriminatory fashion. This explanation is consistent with the Commission's Order No. 2000 requirement that an RTO have "operational authority" over all transmission facilities under its control. Order No. 2000 at 31,090. Second, a clarification is necessary that IPPs or municipal/coop entities located inside another party's control area will provide information directly to the IMA, not through the control area. Finally, rather than control areas providing contingencies as input into the RTO IMA market system, the control area should provide system status to the RTO IMA and the RTO IMA should run the contingency analysis and provide it back to the control area (so that the RTO IMA has the full operational authority over the contingency events)(Op. Prot. at 5).

C4. Short-Term Reliability

1. IOUs

Generally, the IOU sector found the two models similar, but favored the Collaborative Governance Model primarily because more detail has been provided during the mediation.

2. Coops

Local Area Reliability

The Cooperative Sector wants whatever model is adopted to include the GridFlorida Operating Protocol sections that require the RTO to address reliability issues on a proactive basis. (This does not appear in either of the two models.) The Sector argues that TDUs for years have experienced inferior reliability at the hands of the overlying investor-owned utilities.

3. Munis

TO control of line ratings

Three Munis see no significant difference between the two models and abstained. Four Munis oppose the Grids' proposal to let market participant TOs control line ratings in ATC calculations, which they say violates Order No. 2000. One wants the Administrator to have long-term unitary control over reliability.

4. Fed/State (SEPA)

SEPA states that the responsibility for short-term reliability should be in the hands of the System Administrator.

5. IPPs/generators

Level of detail/generators' capacity services

The IPP Sector favored the Collaborative Governance Model primarily because it provided more detail during the presentations, as well as an expressed acknowledgment of the capacity services that could be provided by generators.[59] Many of the same issues mentioned in Characteristic 3 above were identified as reasons.

Control areas/compensation to generators for reliability redispatch

In the SeTrans model, the issue of local control versus the authority of the SA was a primary concern. More specifically, local control areas might exert too much control in the name of reliability. Both proposals need to address the financial relationship between the SA/IMA and generators with regard to exerting control over independent generators for reliability purposes. For example, the Collaborative Governance Model needs to clarify what rights, if any, the RTO will have to call upon a generator for reliability reasons, how such rights would be reflected in individual interconnection agreements and how generators would be compensated for such services. Others noted that the decisions related to this function in the SeTrans model are not transparent to the market. Transparency is also required to ascertain the rationale of decision-making behind actions taken for short-term reliability purposes. Finally, concerns were raised that the RTO vs. local control area issue in the SeTrans model will artificially restrict supply alternatives available to LSEs, leading to a higher cost for the same level of reliability.[60]

6. Marketers

The Marketer Sector supports the Collaborative Governance Model for the LMP/Financial Rights model. The RTO must have full operational authority over all transmission assets and resources offered to it and manage reliability in real time. Marketers fully support the use of the centrally coordinated Real Time Spot energy

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59 While the SeTrans proposal indicated that the RTO should review (and presumably approve) generator maintenance schedules, it failed to acknowledge capacity service (willingness to modify a schedule to assure supply adequacy) or any associated compensation.

60 Under SeTrans' approach, merchant generation could not be scheduled on-line to create an option for energy balancing or other ancillary services unless the owner pre-sold generation equal to its minimum loading level for its minimum run period. Given that such an approach would place control over market access in the hands of a few market participants, it is expected that less supply would be available than if the market access were truly open, as is proposed under the Collaborative Governance Model. This balanced schedule requirement concern would be further compounded by a physical rights-based congestion management.

market, run by the IMA, to support dispatch. Marketers agree that this market should be based on a single optimization program that uses collected bids. This coordinated dispatch function would also manage congestion and provide balancing energy service (Operating Protocol at 5). An RTO-conducted spot energy market is a natural concomitant of the RTO's balancing and generation redispatch functions, which are universally recognized as being necessary for reliable RTO operations. In contrast, the SeTrans proposal for the physical rights model allows lost efficiencies if the nodal price signals (obtained by running the unconstrained schedule) indicate that it would be more economical for a particular generator or load to increase or decrease output, but it cannot as it does not have the required physical transmission right.

7. <u>Consumers/End users</u>

Consumers are concerned that the Collaborative Governance Model's intention to require the redispatch of generation in emergency conditions would cause irreparable harm (including risk to public health and safety) to industrial cogeneration and the associated steam host. As proposed by SeTrans, emergency dispatch of such units is to be negotiated and subject to the terms and conditions of a contract. The RTO's short-term reliability protocols should recognize that such restrictions include those resulting from the integrated nature of industrial on-site generation and the manufacturing process. They suggest that Texas's electric restructuring legislation, S.B. 7, may provide a suitable model: "No operational criteria, protocols, or other requirement established by an independent organization, including the ERCOT independent system operator, may adversely affect or impede any manufacturing or other internal process operation associated with an industrial generation facility, except to the minimum extent necessary to assure reliability of the transmission network." Public Utility Regulatory Act, § 39.151(l).

One Consumer member opines that short-term reliability is more likely to be maintained and enhanced under the SeTrans Model because of the stronger, top-down authority of the System Administrator.

RTO-Wide Roll-In of New Investment

Another Consumer member argues that, consistent with the objectives of Order No. 2000, RTO protocols should promote the development of generation, make available additional supplies of power to the grid, and enhance the reliability of the grid. Because new generation provides benefits to the *entire* system (such as additional power supplies and enhanced system reliability), costs associated with and necessitated by interconnecting new generation to the grid (including interconnection facilities and system upgrades) should be rolled into system costs, not directly assigned. Rolling in these costs will reduce a significant impediment to the development of generation (the financing by a single entity of interconnection facilities and system upgrades, which benefit all users). Rolling those costs in will help eliminate lengthy battles between generators and transmission providers over allocation of interconnection costs, which tend to unduly delay the completion of needed generation.

RTO Core Functions

F1. Tariff Administration and Design

1. IOUs

The majority of the IOUs support the Collaborative Governance Model primarily because it provides detailed plans to deal with cost shifting (e.g., by proposing that certain facilities be phased into rates over a five year period) and also has detailed plans to promote the conversion of existing transmission arrangements to the RTO OATT, as well as the phasing out of zonal rates and costs. The SeTrans proposal lacks any detailed plan at this time for any of these items.[61] The Collaborative Governance Model also offers detailed plans providing options for incorporating public power facilities into the RTO rate on terms that are more favorable than those required under Order No. 2000. There was division among the IOU Sector about "bright-line" tests for including public power facilities: one supports 90KV and above; while another does not support bright line tests.

2. Coops

Cost Shifting

See discussion of pricing under independence and governance, above.

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[61] The SeTrans proposal acknowledges that tariff and rate design will be further developed through a collaborative stakeholder process; therefore, detailed proposals at this time are premature.

Market Power

The Cooperative Sector argues that market power mitigation is a critical issue which neither Plan addresses. Market power must be fully addressed in the context of the market design.

3. Munis

TDU cost coverage

Munis object to the Collaborative Governance Model's proposal to deny full coverage of TDU revenue requirements for the first five years, which they point out will reach further into the future if the RTO start-up date slips. SeTrans responded favorably during mediation to a proffered compromise of full coverage within 2 years if granting it and eliminating pancaking would not raise the average retail rate by 3% or more (Commissioner Wood's threshold in his partial dissent in PJM.) Munis ask that if the Collaborative Governance Model is adopted, this proposed compromise also be adopted to make the Collaborative Governance Model "less toxic to at least some municipals." Like the Coops, Munis contend that the Collaborative Governance Model's rationale for rejecting it is disingenuous. They argue that fully recognizing TDU investment would affect only a few zones (including the Entergy zone, where an agreement already provides for full recognition for one cooperative), and even there at well under 3% of delivered power costs.

Pancaking

Municipals that addressed rate pancaking consistently oppose the Collaborative Governance Model's proposal for pancaking to continue under grandfathered agreements until the five-year phase-out during years 6-10. They prefer an immediate end to pancaked charges, while honoring grandfathered agreements in other respects. The also note that SeTrans has not ruled out the possibility of immediately eliminating pancaking, which it is willing to evaluate collaboratively with information on the magnitude of affected amounts. One Muni and one Muni group recommend that (a) the 3% test for two-year phase-out, as discussed above, be applied to this issue as well, and (b) at the very least, all pancaked charges end by a proximate date certain.

One group of Munis notes the importance of eliminating pancaking for new transactions (which they understand both models provide), by converting service agreements under individual-company tariffs to unified, non-pancaked service under the RTO tariff.

On several other rate design issues where it is not clear that the two proposals diverge, there is no obvious disagreement among Municipals, although not all Municipals have addressed each issue.

Transmission to Bundled Load Should Flow Under Tariff

One Muni is concerned that under the SeTrans model bundled deliveries to retail load will not be provided under the RTO tariff. The SeTrans Supporters' apparent new commitment to take network transmission service for their retail load remains equivocal and qualified. No municipal has disagreed with the position that all load should take RTO transmission.

Zonal Boundaries

One Muni fears that under the SeTrans model, Southern's retail load will pay for transmission by intra-company zone while wholesale load pays for a company-wide zone, creating price squeezes. No municipal has supported that inequitable result.

Obligation to Transfer Transmission-Voltage Facilities

One set of Munis wants transmission owners to have an option to retain control of facilities that function as localized distribution, and believes that only SeTrans may offer that option.

RTO-Wide Roll-In of New Investment

Three Munis support roll-in, which the Collaborative Governance Model partially provides for and SeTrans does not address; no municipal has opposed it.

Point-to-Point vs. Network

One group of Munis fears either model might favor Network Service over Point-to-Point.

4. Fed/State (SEPA)

SEPA believes that a system-wide rate should be established within a relatively short time; the three years recommended by the Tariff Administration and Design working group seems adequate and appropriate. The analysis of cost shifting should be completed quickly, and mitigation should be established as soon as possible.

The SeTrans model anticipates that the proposed zonal rates will be in effect until December 31, 2012. SEPA believes this accords with the expiration in present ITS contracts. SEPA would support an RTO system-wide transmission rate that allows separate treatment for the ITS. SEPA favors a "bright line test" for transmission assets to be included in the rates; SeTrans uses one.

The Collaborative Governance Model's rate design includes regional rates and zonal rates within regions. They propose a time frame of 10+ years to put in place an RTO system-wide rate. The Collaborative Governance Model proposal has a "bright line test" for some transmission assets, and the assets are phased in over a five-year period. It has a functional test for assets to be included in the rate base at inception.

5. IPPs/generators

The overwhelming majority of generators support the Collaborative Governance Model for a number of reasons. In short, the Collaborative Governance Model places all loads, including service on behalf of retail and bundled existing agreements, under the RTO OATT.

The IPP Sector argues that while SeTrans purports to include all load under the RTO tariff, it includes ambiguous language regarding grandfathering of ITS arrangements as well as a general disclaimer to any provisions it can convince its state regulators to later oppose (*see* SeTrans proposal at n.2). IPPs argue that only under the Collaborative Governance Model are all loads subject to the same terms and conditions, and able to rely on an independent RTO to treat all transmission users comparably. Having all load subject to the same terms and conditions and subject to the same pricing provisions ensures that all parties are treated in a comparable fashion and avoids the perception that some customers will be treated differently. IPPs contrast this with the SeTrans model, which states that it will be the "sole provider of *unbundled* transmission service over the facilities that it operates," and which IPPs argue perpetuates the status quo.

The Collaborative Governance Model proposal provides detailed plans to deal with cost shifting (*e.g.*, by proposing that certain facilities be phased into rates over a five-year period) and also has detailed plans to promote the conversion of existing transmission arrangements to the RTO OATT, as well as the phasing out of zonal rates and costs. The SeTrans proposal lacks any detailed plan on any of these items. However, while supportive, some generators suggest that the Collaborative Governance Model proposal should actually commit to transitioning immediately to an SPG RTO region-wide rate rather than after 10 years of RTO operation. The Collaborative Governance Model also offers similar detailed options for incorporating public power facilities into the RTO on terms that are more favorable than those required under Order No. 2000, while imposing no penalties on those parties that are unable to participate.

While the Collaborative Governance Model simplifies intra-RTO generation scheduling and bilateral transactions by presumably (although this should be clarified) eliminating internal point-to-point transmission reservation requirements and related NERC tagging procedures, the SeTrans design would perpetuate those administratively burdensome practices. An effective open access RTO tariff, such as Collaborative Governance Model's, would eliminate the need for scheduled interchange between sub-areas of the RTO (and hence eliminate the need for internal point-to-point reservations and related procedures).

The IPP Sector applauds the Collaborative Governance Model proposal to settle all schedules and bilateral transactions based on the least cost, RTO-wide economic dispatch, and resulting locational prices. They argue that only that approach achieves the increased market scope and open access to the market which FERC intended in Order No. 2000. They consider the SeTrans approach an outdated model built upon an insufficiently defined, unproven and inefficient physical rights-based congestion management platform.

6. <u>Marketers</u>

All Marketers generally, and in some cases strongly, support the Collaborative Governance Model proposal for all load to take service under the IMA-administered RTO Open Access Transmission Tariff ("OATT"). The Marketers also support the conversion of existing transmission agreements ("ETAs") to service under the RTO OATT, on the grounds that a viable Southeastern power market will be valid where all contracts are subject to the same rates, terms and conditions as specified in the RTO OATT.

One Marketer recommended that, while the Collaborative Governance Model proposal to roll in rates for new transmission appears workable for the initial operation of the RTO, the proponents of the model continue to explore innovative methods of recovering the costs of new transmission as access to real time pricing information increases, e.g., incentive returns for new investment in a particular zone.

7. <u>Consumers/end users</u>

Consumers believe neither model is well enough developed to evaluate the impact of their Tariff Administration and Design.

F2. Congestion Management

1. <u>IOUs</u>

The IOU Sector favors the Collaborative Governance Model congestion management proposal, arguing that the financial rights model is the preferable platform for developing a congestion management model. Some favor the financial rights model because it promotes a more efficient dispatch and results in more flexibility for participants. They believe physical rights models bias participants towards managing risk through bilateral contracts. The financial rights model lets participants use the energy imbalance market for spot market purchases; under the physical-based rights markets proposed, balanced schedules must be submitted and any significant reliance on the spot market will be penalized. These penalties are unnecessary and inhibit alternative risk management options. One sector member, while initially expressing reservations about the financial rights model, supports the Collaborative Governance Model's revised congestion management proposal. They contend that this proposal should provide certainty of delivery and price, options to hedge transmission risks, and liquidity to the marketplace.

2. <u>Coops</u>

The Cooperative Sector has varied opinions on this complicated issue. Some favor a financial model, while others prefer a physical model. All agree that existing firm transmission customers must be allocated congestion rights (in a financially neutral manner) consistent with their current and future requirements for serving native load. They note that the Collaborative Governance Model indicates that "to effect a fair conversion from today's tariffs to an RTO tariff, existing long-term load commitments must be taken into account." As the sponsors explain, an allocation of initial auction **revenues** to existing firm transmission customers is insufficient, because of the immaturity of the marketplace for such rights, and the attendant risk and uncertainty. To avoid imposing substantial new transmission-related costs on entities (like the

Cooperatives) that currently serve firm loads, an allocation of rights to existing firm transmission customers must be part of any changeover to a new congestion management regime. Auctioning these rights may be in the best interests of marketers and IPPs, but it may increase costs to consumers, without concomitant benefits.

3. Munis

Most municipals prefer the financial/LMP model that is now the Collaborative Governance Model's platform to the SeTrans physical rights model. One Muni abstained. One group of Munis is not inherently opposed to the financial model, but sees it as a further evolution that should be deferred, with one of the physical models implemented as the start-up method. One Muni supports the SeTrans model. Another sees substantial similarities between the models, but prefers SeTrans'.

Municipals emphasize that under either proposal, congestion rights should be assigned to load and that market power issues must be resolved well before any charges based on markets take effect.

4. Fed/State

SEPA prefers SeTrans' Hybrid model, because it appears to take the best features of both the physical model and the financial model. The SeTrans proposal uses the Physical or Flowgate model, but provides prices using the LMP method.

SEPA believes that, given the early stage of this process, much more discussion will be needed to implement the ultimate proposal, no matter which model is chosen. Therefore, it is important to continue a meaningful, ongoing, collaborative process to discuss and work out the differences. SeTrans recognizes that a comprehensive collaborative process with stakeholders and participants will be necessary to complete the congestion management function.

5. IPPs/generators

The IPP Sector favored the Collaborative Governance Model LMP/FCH congestion management platform because it allowed for economic efficiency, liquidity, and flexibility, certainty of pricing and delivery, and congestion "buy through." Also, many argued that this model has been proven in other forums. Moreover, during the mediation discussions, the IPP Sector articulated many reasons why the alternative physical rights based congestion management approach was unworkable. SeTrans proponents failed to provide adequate responses to those concerns and fell far short of demonstrating that the physical approach is superior to the best practices (financial rights-based CMS) as FERC required of GridSouth in its July 12th RTO Order on a similar congestion management approach.

Many generators prefer auctioning congestion rights instead of allocating or "grandfathering" those rights. Some generators would accept an interim allocation of rights, provided those rights were financial (Collaborative Governance Model) and a firm date was established for determining whether it is appropriate to continue such an allocation or for transitioning altogether to auctioning such rights. Many generators like the features of the proposals that allowed for and encouraged secondary markets for congestion rights. One argued that a variety of financial instruments, including options and obligations, should be available to meet the needs of market participants.

6. <u>Marketers</u>

The Marketer Sector strongly supports the Collaborative Governance Model' s LMP/Financial Rights platform because it facilitates congestion management in real time and will realize the Commission's Order No. 2000 directives that "ensure truly non-discriminatory transmission service". (See *GridSouth Transco, LLC, et al*, 96 FERC ¶ 61,067 at 61,287 (2001)). It also supports and will promote many of the other characteristics and functions, including Independence, Operational Authority, Short Term Reliability, Ancillary Services, Interregional Coordination, and Planning and Expansion. Perpetuation of current discriminatory practices will continue without the open and transparent real time spot market that is accessible to all market participants – not just incumbent control areas.

For the market "that will support the billions of dollars of capital investment in generation and demand side projects necessary to support a robust, reliable and competitive electricity marketplace" (id.) to be established, participants need flexibility. For example, participants may choose to buy or sell energy to the spot market, (or alternatively, decide to interrupt, or sell distributed or on-site generation, etc.), enter into bilateral contracts, buy through congestion; and self provide. Moreover, a robust spot market (without a day-ahead balanced schedule provision with penalties as found in the SeTrans model) provides market transparency with visible real-time pricing upon which to base an active market in providing hedging tools with a wide variety of energy products for utilities and end users.

Accurate real-time nodal prices (that are set by the participation of all market participants) will provide the essential price signals to best determine the location and necessity of new investment in generation, transmission, and demand side management products, as well as new innovation, which facilitates the Planning and Expansion Function.

The LMP/Financial Rights model also provides the most flexibility to participants for developing a variety of forward market instruments to manage real-time price risk (for example, options/obligations/FTRs/Flowgates, etc.). In addition, the LMP/Financial Rights model is consistent with the Commission's directive to look to best practices in other regions.

While Marketers fully support the basic LMP/Financial Rights model, two elements are now proposed that warrant further mediated discussion: (1) the balanced resource requirement (and more fully the day-ahead process) and (2) the allocation of transmission rights without an auction. The Collaborative Governance Model does appropriately recognize that these are issues that warrant further discussion in a mediation-type process. The mediation participants spent approximately a week working on congestion management, with the result that most participants favored the LMP/Financial Rights model (with many initially favoring the physical rights model). Because the participants did not have adequate time to fully discuss the day-ahead scheduling process (including the balanced resource issue) and allocation/auction, Marketers suggest further mediated discussions.

Marketers are concerned that the "Balanced Resource" requirement, as drafted, could be interpreted to require day-ahead balanced schedules.[62] The stated purpose of "resources", "ICAP", "reserves" (or any of the other names/procedures used across the country) is security – to ensure that there are enough resources built on a forward time frame that can be called upon to run in real time if necessary.[63] Some of these markets, such as PJM, include a day-ahead reliability assessment, but do not include a day-ahead

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[62] Marketers oppose the SeTrans congestion management model for the primary reason that it perpetuates the current discriminatory process of requiring "day-ahead balanced schedules" that preclude the use of much of the market to participants other than generation and load owning utilities.

[63] However, these capacity products can be a double-edged sword in that the more customers pay for capacity, the less incentive a resource has to run to recover its operating and capital costs. In addition, the Grid model appears to be drafted with mandatory bidding of load, but voluntary bidding by generation. This can create inefficiencies and should be further discussed.

balanced schedule requirement.[64] A workable solution should be attainable with some further discussion among the participants.

Marketers agree that "allocation" must be dealt with; however, there are two ways to think of allocation. Participants (including end users) can be allocated financial transmission rights instruments (as proposed by the Grid) or allocated the cash proceeds that result from auctioning the financial transmission rights instrument. Marketers prefer allocating the cash proceeds because this provides a method to determine the market value of the instrument. If the instruments themselves are allocated, there is no way for those who receive them to know whether they are truly valuable or not.[65]

Because of the importance of these two issues and the variety of ways to address them, it is important for the Southeast to fully discuss the benefits and negatives of the various proposals before finalizing a procedure.

7. Consumers/End users

Consumers believe that selecting the Day Two congestion management model should be left to further discussion in a collaborative effort. Consumers believe that either the financial or physical rights approach will work depending upon how a liquid and transparent forward market for transmission rights is structured and guaranteed. Congestion management efforts need to be worked out in a credible, inclusive collaborative process regardless of which Model is ultimately selected. Any financial model must include financial rights that lend themselves to establishing a liquid and transparent forward market for transmission rights.

Neither model addresses whether loads will be eligible to participate in the congestion management market. Whether a physical rights model or a financial rights model is adopted, loads should be eligible to participate in the congestion management market as resources, and they should be fairly compensated for their contribution.

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[64] A day-ahead balanced schedule requirement is a barrier to entry in that it restricts the ability of participants to fully respond to the LMP-based real-time price signals.

[65] There have been ongoing discussions in PJM (where instruments were initially "perpetually allocated") that the allocation of the instrument has led to the lack of liquidity in the PJM FTRs.

Two Consumers members believe if the Financial Transmission Rights proposal of the Collaborative Governance Model is adopted, it must include all of the features of the SPP Hybrid Congestion Management System, because only the complete SPP Hybrid Congestion Management System was developed through a collaborative process. The SPP collaborative process did not adopt Locational Marginal Pricing with Financial Transmission Rights, but rather it adopted a congestion management system that includes a flexible set of financial transmission rights known as Financial Congestion Hedges (FCHs), which are designed to promote a liquid and transparent forward market for transmission rights. The SPP Hybrid Congestion Management System includes not only LMP and point-to-point financial transmission rights that are obligations, but also many other types of financial rights with characteristics that better lend themselves toward establishing a liquid and transparent forward market for transmission rights.

These two sector members also believe that without a liquid and transparent forward market for transmission rights, electricity markets will be unstable with prolonged periods of severe generation deficiencies and surpluses. Such an unnecessarily unstable market is not conducive to workable competition and would be highly inefficient. Market participants will be making generation and transmission infrastructure investment decisions based on their perception of future electricity prices at particular locations on the Southeastern power grid. Only a liquid and transparent forward market for transmission rights will provide accurate price signals to those market participants that will help ensure sufficient infrastructure is constructed "just in time" to meet the demand of consumers.

F3. Parallel Path Flow

1. <u>IOUs</u>

The IOU sector generally agreed that both models largely avoid consideration of parallel path flows. Both plans contend that a larger RTO encompassing the Southeast as a whole will mean little to no uncompensated flows. Two members of this sector disagree, believing that they are very likely to be on or adjacent to an RTO seam. One favors the Collaborative Governance Model because the scope of its RTO would internalize parallel path flow, and congestion management and transmission rights would alleviate some parallel path flow problems.

2. <u>Coops</u>

The Coops did not comment on Parallel Path Flow.

3. Munis

Every voting municipal prefers the SeTrans model. Many assert that SeTrans is better designed to accommodate and attract public power participation — thereby achieving a broad and contiguous Southeast RTO that will internalize parallel path flows.

4. Fed/State (SEPA)

SEPA is most concerned that all TOs in the region become participants to reduce parallel path flow impact. SeTrans has participation from TO PPUs; the Collaborative Governance Model, at this time, does not.

5. IPPs/generators

The IPP Sector recognizes that a large region would minimize any internalized parallel path flows, and only the Collaborative Governance Model would actually achieve the ability to manage such flows in real time operations. Another key point raised by several generators on this issue was that the financial rights congestion management model will lead to less parallel path flow and resulting TLRs when compared to the SeTrans physical rights model.

6. Marketers

All Marketers agree that it is appropriate to authorize the RTO to develop specific parallel path flow procedures in the future. The Marketers concur that the Collaborative Governance Model's proposed FCH/LMP Financial Rights congestion management model will help to minimize inter-RTO parallel path problems and provide a solid foundation upon which to develop and implement procedures to address parallel path flow issues within the Southeast and its neighboring regions.

7. Consumers/End users

Parallel path flow issues will be reduced if a single RTO is established for the entire Southeast. To the extent the SeTrans proposal is more successful in attracting non-divesting and non-jurisdictional TOs to participate in this RTO, the SeTrans proposal will more effectively and efficiently meet the requirements of this function.

F4. Ancillary Services

1. <u>IOUs</u>

The IOU sector generally noted that both models need more detail on this function. Nearly all IOUs supported the Collaborative Governance Model, perceiving a commitment to move toward bid-based mechanisms for ancillary services. Nearly all expressed support for the option to self-supply ancillary services.

2. <u>Coops</u>

Market Power

The Cooperative Sector argues that market power mitigation is a critical issue which neither Plan addresses. Market power must be fully addressed in the context of the market design, including markets for ancillary services.

3. <u>Munis</u>

Every voting municipal prefers the SeTrans model. Many find SeTrans' largely blank slate and promise of collaborative development superior to the known, and perhaps discriminatory provisions of the Collaborative Governance Model balancing proposal (*e.g.*, the load forecast penalty and "settlement zone" provisions). Also, as discussed under C1, Municipals believe that the Administrator, not the Transco, should be the market designer.

4. <u>Fed/State (SEPA)</u>

SEPA can find no significant differences between the two models.

5. <u>IPPs/generators</u>

While the IPP sector generally noted that the Collaborative Governance Model needed more detail on this function, SeTrans presented virtually no detail. Nearly all generators supported the Collaborative Governance Model because of a perceived commitment to moving toward bid-based mechanisms for ancillary services on a relatively quick time frame, particularly when compared to SeTrans. Nearly all expressed support for the option to self-supply ancillary services, and most generators strongly supported the development of a capacity market as mentioned in the Collaborative Governance Model, which, in many respects, incorporated GridFlorida's initially proposed Installed Capacity and Energy obligation. While not expressly acknowledged as a service under the SeTrans proposal, it would require generators to submit maintenance schedule requests to the SA in order for the SA to assure supply adequacy. While IPP/Generators are willing to provide capacity services in return for fair and reasonable compensation, SeTrans proponents required the provision of the service without any explicit acknowledgment of that capacity service or mention of its compensation. The Collaborative Governance Model proponents must also clarify that generators will be compensated if required to provide ancillary services.

6. <u>Marketers</u>

The Marketer Sector generally prefers the Collaborative Governance Model because it uses nodal pricing for congestion and imbalance. One prefers the SeTrans Model. While the Collaborative Governance Model does not initially use a market-based approach for ancillaries, use of this type of LMP/Financial Rights model should facilitate establishment of a market for ancillary services. Such an ancillary market is considered necessary in order to provide numerous services to customers located in another party's control area (including wholesale customers, such as municipals and coops.) For example, the ability of energy and service providers, such as marketers, IPPs, and utilities, to compete to serve these entities is hindered when the control area controls the ancillary services.

7. <u>Consumers/End users</u>

Consumers note that neither model offers any detail about a proposed energy imbalance market or any other ancillary services, and both models anticipate developing a real-time balancing market and other ancillary services markets later in the RTO development process.

Neither model discusses the role of industrial loads in the provision of ancillary services. Loads such as those of Steel Manufacturers and many members of Industrial Consumers are large and price responsive. These loads can be interrupted or curtailed very quickly, on short notice, and curtailment is easily verified.

Utilities use their ability to interrupt large industrial loads as *spinning* and *non-spinning reserves*. Similar loads have agreed to interruption on short notice to assist their utilities with *frequency control* in the event that a generating resource trips. Regardless of which RTO model is adopted, loads should be eligible to provide, and should receive compensation for providing, ancillary services such as frequency control and operating reserve. Also, the *energy imbalance* market and all other ancillary service markets that are developed should be structured so as to facilitate the participation of industrial loads.

Consumers believe that the Collaborative Governance Model's congestion management proposal, to the extent it is actually based on the SPP financial rights hybrid model, may provide a good ancillary services market for supporting the retail access needs of large industrial customers. Thus, they submit, both functions 2 and 4 need to be resolved in a collaborative process – as proposed by the SeTrans model. However, they submit that the SeTrans proposal, which adopts a balancing energy market based on some arbitrary system of penalties, must be rejected.

F5. OASIS/TTC/ATC

1. <u>IOUs</u>

While the IOU Sector indicated that both models are essentially identical on this RTO function, one IOU supports the Collaborative Governance Model because it contains detailed protocols.

2. <u>Coops</u>

The Coops did not comment on OASIS/TTC/ATC.

3. <u>Munis</u>

Every voting municipal prefers the SeTrans model because SeTrans places transmission gatekeeping in a single, permanent, and market-independent institution, the ISA. Municipals oppose the Collaborative Governance Model's proposals to:

- empower market participants (control area operators) to control line rating inputs to ATC:
- deputize multiple ITCs as the entities responsible for system impact and interconnection studies, thus giving them a transmission gatekeeping role; and,
- potentially have the Transco re-possess Administrator functions, thereby undercutting from the outset the Administrator's ability to become an efficient gatekeeper.

4. <u>Fed/State</u>

SEPA can find no significant differences between the two models.

5. <u>IPPs/generators</u>

While both models are essentially identical on this RTO function, the IPP Sector favored the Collaborative Governance Model because the RTO, as OASIS administrator, will independently calculate TTC/ATC. Some respondents also stated that the Collaborative Governance Model LMP/FCH congestion proposal was more appropriately aligned with the Collaborative Governance Model's proposed OASIS TTC/ATC functions. The SeTrans model, on the other hand, was viewed as inferior because the proposed role of the TOs and existing CAOs in determining TTC/ATC undermines the independence of the RTO's operational authority.

6. <u>Marketers</u>

The Marketers strongly support the Collaborative Governance Model proposal to place responsibility for the OASIS administration and calculation of ATCs and TTCs as described in the Operating Protocol with the IMA, provided the IMA is truly independent.

7. <u>Consumers/End users</u>

Consumers feel the Collaborative Governance Model RTO platform is less preferable, because after five years, the Transco could assume responsibility for OASIS/ATC/TTC, compromising the IMA's independence to administer these functions.

F6. Market Monitoring

1. <u>IOUs</u>

While the IOU Sector indicated that both models are essentially identical on this RTO function, two supported the Collaborative Governance Model, while one slightly prefers the SeTrans market monitor because it is selected by the Stakeholder Advisory Committee.

2. <u>Coops</u>

The Cooperative Sector argues that market power mitigation is a critical issue which neither Plan addresses. Market power must be fully addressed in the context of the market design, including markets for ancillary services, as well as the market monitor.

3. Munis

Almost every municipal that addressed market monitor selection and governance prefers the Collaborative Governance Model GridFlorida-based method. Two Munis prefer the SeTrans method under which the Advisory Committee selects the Monitor. Several Munis note that by solving structurally the problem of the Transco favoring its owned facilities, SeTrans obviates monitoring for such bias; one group of Munis supports SeTrans on that basis.

4. Fed/State (SEPA)

Both models base their Market Monitor on Grid Florida's. The major difference SEPA sees is that the Market Board of Directors selects the Market Monitor in the Collaborative Governance Model's proposal, while the Stakeholder Advisory Committee selects the Market Monitor in the SeTrans proposal. SEPA prefers that the Stakeholder Advisory Committee select the Market Monitor, as in the SeTrans proposal.

5. IPPs/generators

All IPP Sector representatives support the Collaborative Governance Model market-monitoring proposal, in part because, although SeTrans has indicated it will largely adopt the GridFlorida model, which serves as the platform for the Collaborative Governance Model, the SeTrans model lacks the detail and provides only a promise to implement such a model. IPPs argue that the SeTrans proposal that the Stakeholders elect all directors to the Market Monitor Co. seems unwise given the SeTrans proposal to allow market participants to retain local control area dispatch authority. IPPs believe that the Commission-approved Grid Florida model, underlying the Collaborative Governance Model, contains sufficient detail upon which to base a decision. Benefits of the proposed model include: (1) an independent and separate market monitoring entity ("MonitorCo"), (2) an independent MonitorCo board selected by the Advisory Committee and the Transco, (3) monitoring authority over both the energy and ancillary service product markets including compliance by the Transco with the RTO OATT, (4) independent budget authority, and (5) increased authority to review tariff changes. These protections provide an added level of comfort to all market participants subject to the RTO OATT and further exemplify the Collaborative Governance Model's superior commitment to assuring overall RTO independence.

6. <u>Marketers</u>

The Marketer Sector generally supports the Collaborative Governance Model proposal (with only one exception). Marketers do not support allowing the Market Monitor to impose mitigation measures, unless approval by the Commission is required before the measures can be imposed.

7. <u>Consumers/End users</u>

Under the Collaborative Governance Model RTO platform, the Market Monitor would have the power to review proposed RTO tariff changes. It is unclear whether the Market Monitor would have this power under the SeTrans Model.

In the SeTrans Model, the SAC selects the Market Monitor while in the Collaborative Governance Model, both the SAC and the Transco have input into selecting the Market Monitor. These sector members believe that the SeTrans Model is preferable in this respect because allowing the Transco to have input into selecting the Market Monitor could compromise the independence of the Market Monitor.

F7. Planning & Expansion

1. <u>IOUs</u>

The majority of the IOU Sector supports the Collaborative Governance Model. However, one does not, believing that planning for assets owned by other entities should not be performed by an asset owner.

2. <u>Coops</u>

Coops did not comment on Planning and Expansion.

3. <u>Munis</u>

Every municipal prefers the SeTrans model because SeTrans centralizes the RTO's planning authority and responsibility in the Administrator (a single institution not biased by owning some of the transmission in its footprint), rather than giving a Transco the lead role and dispersing some of the RTO's planning authority among possible multiple ITCs. One group of Munis also believes that (a) Order 2000 did not seek to push municipals towards divesting ownership rather than divesting control, and accordingly ITCs should not have greater localized planning rights than other participating owners, and (b)

SeTrans properly allows transmission owners more planning authority over facilities that may have a transmission voltage but function as localized distribution. Several municipals note that contrary to the Commission's ruling in *GridSouth*, both models give non-divesting transmission owners a first refusal right to build new facilities in their areas (*see, e.g.*, Grid Group Planning Protocol §§ II.B.1-2), rather than letting the RTO select the most efficient builder.

4. <u>Fed/State</u>

SEPA believes that it is important that the organization responsible for planning not be, or appear to be, biased in executing its planning responsibilities. SEPA feels that it is critical that the System Administrator have the responsibility for planning and expansion. Allowing the Transco to be responsible for planning may result in its favoring its own transmission system. Both models have one-stop planning; but SeTrans gives responsibility for planning and expansion to the System Administrator, while the Collaborative Governance Model gives responsibility for planning and expansion to the Transco.

5. <u>IPPs/generators</u>

Planning is the one issue where the comments of the IPP sector were most mixed. While the Collaborative Governance Model was preferred, many generators expressed concerns about the potential for the for-profit Transco to favor transmission solutions compared to generation solutions in the planning process. Also, many noted that the exact delineation of functions to the ITC were a concern. The primary reasons for favoring the Collaborative Governance Model was that the Commission had already approved a similar structure in GridFlorida, and the Transco was clearly the ultimate authority in the Collaborative Governance Model, but the SeTrans proposal made it unclear what exact authority would be ceded to the TOs in their contracts with the SA. Finally, many generators recognized the need for the Transco to have strong authority in order to stimulate investment.

6. <u>Marketers</u>

The Marketer Sector generally prefers the Collaborative Governance Model, although one prefers the SeTrans model. In general, the Marketer Sector believes that adopting a market design similar to that used in neighboring RTOs (the FCH/LMP Financial Rights model) will facilitate Planning and Expansion. The Collaborative Governance Model plan proponents have embraced the FCH/LMP congestion management methodology as the single platform on which to design the Southeast RTO markets --- further enhancing support for this model among the Marketer Sector.

The Marketers call the Collaborative Governance Model's requirement that the Transco consider market solutions, including any proposed merchant- or participant-funded expansion projects, a positive aspect. Some Marketers believe that this model would be improved if the ultimate planning process resided with the IMA, rather than the Transco, to assure that the planning decisions are made by an entity with no commercial interest in the outcome. If the planning process remains with the Transco, they submit that a clearer protocol should be developed to allow for meaningful and substantive input from the IMA and SAC.

7. Consumers/End users

The SeTrans Model advances a more centralized planning structure that Consumers believe is more efficient. The Collaborative Governance Model could split essential planning functions among two or more entities. While the GridFlorida protocol attempts to address this hierarchical relationship, under the Collaborative Governance Model, the "ultimate planning authority" resides with the RTO (i.e., may be split among multiple entities). They believe this problem could well become unworkable if the Transco's assets account for only a portion of the total transmission assets under the RTO's footprint.

The SeTrans Model vests planning and expansion authority in the Independent System Administrator, which would not own assets, and, therefore, would have no incentive to discriminate in favor of its own facilities. In this respect, the SeTrans Model is preferable. However, under the Collaborative Governance Model, once the Transco is independent, it may be more successful in securing investment for expansion than the Independent System Administrator might be in the SeTrans Model.

F8. Interregional Coordination

1. IOUs

The IOU sector concludes that neither model addresses the issues of interregional coordination. Two believe they are very likely to be on or adjacent to an SPG RTO seam and feel that this issue needs to be addressed.

2. Coops

Coops did not comment on Interregional Cooperation.

3. Munis

Every voting municipal but one prefers the SeTrans model. Many assert that because SeTrans is better designed to accommodate and attract public power participation, it will better achieve a broad and contiguous Southeast RTO that will make inter-regional issues less important. However, one set of Munis states that while neither model addresses this function, it votes for the Collaborative Governance Model because Entergy and the rest of SPP form a natural market area that should remain within one RTO.

4. Fed/State (SEPA)

SEPA has "seams" (or pancaking) issues at this time between Alliance RTO (Virginia Power) and the Southeast RTO (Carolina Power & Light). Additionally, "seams" issues will result if TVA is not a participant in the Southeast RTO. SEPA believes that an aggressive approach to this issue is important, and endorses the SeTrans model.

5. IPPs/generators

As a group, the IPP sector favored the Collaborative Governance Model, although several feel that both models need more development in this regard. The primary reasons for supporting the Collaborative Governance Model are that the Collaborative Governance Model appears to have a larger geographic scope, the authority of local control areas in the SeTrans model would likely lead to more seams issues, and the financial congestion management model would smooth or eliminate seams to the north. One dissented from this view because of its concern that under the Collaborative Governance Model the Transco would have the authority to resolve seams issues, whereas under the SeTrans model, the SA would have such responsibility.

6. Marketers

Recognizing that inconsistency among markets will only create seams issues, the Marketers strongly support adoption of the Collaborative Governance Model's proposed FCH/LMP Financial Rights congestion management platform as a means of minimizing interregional coordination problems. Also, the Marketers urge the Commission to continue its Interregional Coordination initiative, which it launched earlier this year in the Commission's technical conferences.

7. <u>Consumers/End users</u>

Members of this sector felt that the discussion of this function is better articulated in the SeTrans Model, which would have the ISA run this function. They feel the SeTrans plan proponents seem more aware of the problem, though lacking in answers. The Collaborative Governance Model's response was minimal and implied that this function was not important. However, they feel that neither model addresses Consumers' need for one-stop-shopping and the elimination of rate pancaking throughout each interconnection, which is what function eight is all about.

IV. STATE and LOCAL COMMISSIONS

The Commission initiated mediation for the purpose of facilitating the formation of a single RTO for the Southeastern United States. To aid the parties in this goal, the Commission directed the undersigned Administrative Law Judge and former Chairman Herb Tate, an independent consultant with a high level of familiarity with and knowledge of the electric industry, to convene a meeting and to mediate settlement discussions for a period of 45 days with all of the parties in the Southeast Dockets referenced herein above. Among others, the State Commissions, were also invited to be present and to engage as full participants in the mediation.

Consistent with the goals of Order No. 2000, the Commission's July 12th Order for the formation of a single RTO for the Southeast contemplates an RTO of sufficient scope and configuration to permit the RTO to maintain reliability, effectively perform its required functions, and support efficient and non-discriminatory power markets. <u>See</u> Order No. 2000 at 31,079. Accordingly, both models presented for the Commission's consideration in this Mediation Report envision an RTO that comprises the entire Southeast region. Such an RTO would be larger than any RTO that has been formed or proposed to date. Participation by all eligible transmission owners (excepting members of the Southwest Power Pool who have the option to join a Midwestern RTO), in the Southeast Power Grid RTO would include transmission facilities in ten states: North Carolina, South Carolina, Georgia, Florida, Alabama, Tennessee, Mississippi, Arkansas, Louisiana, and Texas. Accordingly, these State Commissions were invited to be present and to engage as full participants in the mediation.

The Commission's July 12, 2001, Orders may have taken many State Commissions by surprise. Prior to this Order the various State Commissions had been involved in

"Stakeholder" processes which were forming the RTO platforms known as "Grid South" (for the Carolinas), "Grid Florida" (for Florida), "SeTrans", (primarily for Georgia and Southern Company's other operating territories in the States of Alabama, Mississippi, and Florida) and SPP/Entergy taking in Entergy's territories in Louisiana, Mississippi, Arkansas, and SPP's members in Arkansas, Tennessee, and Oklahoma. Through these "Stakeholders" processes some State Commissions were at least familiar with each RTO's governance structure and operational model. The Florida Commission, despite FERC's approval of the "Grid Florida" model, still initiated "prudency proceedings" regarding the formation of an RTO, for Florida, as well as a rate case proceeding to determine the cost impacts of the RTO on transmission rates. Through these proceedings, Florida is attempting to determine the costs versus benefits to its retail ratepayers. Florida in fact conducted an 18-month Stakeholder process to develop its GridFlorida model before presenting that platform to the FERC for its approval. Similarly, "GridSouth" conducted stakeholder processes with the South Carolina and North Carolina Commissions as well as other Stakeholders before filing the its RTO model with the Commission.

The SeTrans RTO model had a more limited stakeholder process through discussions with public power entities and the Georgia Commission prior to its filing with the FERC. Entergy had discussions with its State Commissions in Alabama, Arkansas, and Mississippi but it is unclear of the extent of any Stakeholder process prior to or after their RTO filing.

As previously stated, the State Commissions were invited to actively participate with the mediation team and the nearly 200 Stakeholders and participants in this intense, forty-five day mediation process. At the beginning of the process, several State Commissions attended the first few mediation hearings to voice their objection to the Commission's July 12th Orders on both procedural and substantive grounds. The State Commissions indicated that they viewed these Orders as a departure from Order 2000. At the early mediation meeting, most Commission representatives expressed apprehension about being too actively involved in the mediation process, since they wanted to preserve their option to challenge the process at a later time and to avoid the appearance of a conflict of interest with ongoing or potential State Commission proceedings. However some Commissions continued to send State Commission representatives, or Commissioners intermittently to "monitor" the mediation process. The Arkansas State Commission was the only State Commission to fully attend and participate in the 45-day mediation process. The Arkansas Commission was fully and actively engaged in each step of the process.

The mediation team issued written communications within the first ten days of the mediation process, and oral communications several times thereafter, inviting all State

Commissioners in the Southeastern RTO Region "footprint" to meet with the mediation team. These meetings were designed to give Commissions an opportunity to discuss substantive issues and concerns about the RTO models being debated in the mediation process. Several meetings were established between State Commissioners and the Mediation team.

The first meetings were held during the weeks of July 23 and July 30, 2001, where the mediation team held separate meetings with either groups or individual State Commissioners. For instance meetings were held in groups with Mississippi and Georgia Commissioners together, Louisiana, City of New Orleans, Florida, South Carolina together while individual meetings were held between the mediation team with South Carolina, North Carolina (conference call) Arkansas, Florida, Louisiana, and the City of New Orleans. These meetings allowed the Mediation team to share with the State Commissions the progress in the Mediation discussions as well as to hear Commissioner comments and concerns. Shortly after the meetings had concluded, the mediation team sent a written communication to the State Commissioners inviting their continued involvement in the mediation process and inviting them to future meetings with the mediation team.

Through these various communications, the mediation team informed the State Commissions that the mediation efforts would focus on the basic issues of governance and independence in the context of the four RTO models which had been submitted to the Commission for consideration in the various filings for the Southeast to date, and to develop a business plan for the remaining characteristics and core functions required from an RTO under Order 2000. How those functions would be administered on a day to day basis, methodology for calculation for ATC, TTC, Congestion Pricing, the allocation of FTR's Actual Tariff Design, Calculation of Revenue requirement including whether to "grandfather" existing contracts agreements recovery for transfer of transmission pricing within the Region, dispatchability of generation units, load and voltage balancing and coordination, establishing of energy, capacity, and ancillary services markets, interconnection rules, transmission expansion and planning protocols, and other operational issues, would all be issues addressed by the RTO models that were evolving and developing during the course of this mediation process. The goal of the mediation team in working with the State Commissions was to afford them the level of involvement in the details of the formation of the RTO models that would be necessary to address their specific concerns regarding these issues in the context of impact reliability on rate, native load and transfer of Transmission assets.

On August 13, 2001, the State Commissions of Alabama, Georgia, Mississippi Louisiana, City of New Orleans, North Carolina, South Carolina filed requests for rehearing of the Commission's July 12, 2001, Order in Docket No. RT01-100 as well as other related Orders to the previous RTO filings. The mediation team continued to reach out to State Commissions by phone and by written correspondence and e-mail, inviting them to future meetings with the mediation team, to participate in the mediation process and to ensure that they would be included on the "Restricted Service List" in order to receive mediation documents in accordance with Rule 606 confidentiality protections.

During the final week of mediation, August 27 to August 31, the Mediation Team scheduled two meetings for a final briefing with Southeastern State Commissioners. Two separate days were set up; Tuesday, August 28, and Thursday, August 30, to accommodate State Commissioners schedules. On August 28, the Mediation Team met with Commissioners from North Carolina and Florida, and on August 30 with Commissioners from Mississippi, Arkansas and Oklahoma.

State Commissions have expressed several areas of concern regarding the Commission's July 12, 2001, Order establishing a mediation process for the formation of a single regional Southeastern RTO which Mr. Tate has attempted to summarize for us as follows:

- First, a vast majority of State Commissions felt that the Commission had not conducted a "cost-benefit" analysis to justify the formation of a single RTO for the Southeastern region. Florida, which was the only State Commission not to file a Motion for Rehearing, is currently in the process of conducting its own "prudency" review on the Grid Florida RTO and its impact on retail rates. The conduct of such a cost analysis for establishing, and operating a single Regional RTO for the Southeastern may serve to allay State Commissions fears about speculative, substantial costs to establish an RTO which could raise transmission rates to rate payers within their jurisdiction. The Mississippi Commission mentioned in its Motion for Rehearing that "Grid South" had projected significant costs to construct and operate an RTO just for the Carolinas. The Mississippi Commission expressed concern that by extrapolating these costs into an eight State Southeastern Regional those potential significant costs would cause an unwarranted increase in transmission rates for certain low cost energy States such as Mississippi. Extrapolation of these RTO costs for the entire Southeastern Region seems unwarranted because it ignores for one, "economies of scale" and the elimination of duplication of functions and second, it ignores the RTO's initial reliance on existing control centers and its infrastructure to perform many of the day to day operations for an RTO. The costs for these Control centers are already being recovered in current Transmission rates charged to Customers. If costs were found to be "significant" and had the potential to raise both transmission and retail rates and bills to customers, a "benefits analysis" for retail customers may be necessary. Either way, the Commission could explore the feasibility of a rate setting process for the recovery of the revenue requirement for the RTO which would involve State Commission participation with FERC.

- Second, certain State Commissions are concerned that FERC's goal of establishing a region-wide "postage stamp rate" within the RTO, will produce "cost shifting" and thereby create "winners" and "losers" among and between State retail customers. During the various "Stakeholder processes" that had occurred leading up to the filings of the four Southeastern RTO's, some State Commissions had gained a level of comfort for the amount of "cost shifting" which might occur within those smaller RTO region proposals. However, they were very apprehensive as to the immediate and near term "cost shifting" that might impact their retail rates if a "postage stamp" rate is determined to be the appropriate approach at the onset of the Southeastern RTO. Of course, the Commission has recognized many of these issues, including the fact that cost shifting has been an important concern of state commissions, as well as one of the major issues associated with establishing independent system operators and RTOs to date. See, e.g., Order No. 2000, FERC Stats & Regs. ¶ 31,089 at 31,176 ("Each ISO approved by the Commission has struggled with the problem of cost shifting among the various individual transmission owners that make up the ISO."); Midwest Indep. Transmission Sys. Operator, Inc., 84 FERC ¶ 61,230 at 62,151 (1998) (Commission recognizing that cost shifting and cost recovery mechanisms are of "paramount concern" to transmission owners). The Mediation Team has discussed with the State Commissions the recent Order in Alliance where the Commission allowed the RTO a five-year "phase-in" period to adjust current transmission rates to a "single postage" stamp rate and eliminate "pancaking" due to existing contracts and wires arrangements between transmission owners and load serving utilities.

- Third, certain Commissions have expressed concerns that the Commission's call for a single RTO for the Southeast Region may have unintended preemptive implications binding or impairing State Commissions ability to approve or disapprove the transfer assets from the regulated utilities to the RTO particularly to a Transco. The North Carolina Public Utilities

Commission asserts that the Commission's July 12, 2001, Order calls into question States approval or disapproval rights for the proposed transfer of assets. The City of New Orleans request for rehearing and clarification asserts that the City of New Orleans has jurisdiction to approve or disapprove Entergy's transfer of assets. The City of New Orleans request was filed base upon Entergy's earlier submitted Transco proposal, which has been rejected by FERC. However, the City of New Orleans claim will still be relevant for the new SPG RTO platform model which Entergy has joined in with "Grid South", and "Grid Florida". The City of New Orleans, in its filings, believes that the Commission's July 12th Order calling for a single RTO raises the issue of limiting the ability of the state and local regulators to take certain actions regarding Transfer of assets to an RTO. The Council feels that Entergy and other RTO participants could argue to the Commission, that the "federal mandate" (to form a single RTO through July 12, 2001, Order) preempts any state or local authority's ability to approve or disapprove there proposed Transfers. The City of New Orleans, therefore, asks FERC for clarification on the issue of preemption of State and local regulators authority due to the FERC issuance of the July 12, 2001, Order. Further, as previously mentioned, the State of Florida, which did not file a request for rehearing regarding FERC's July 12, 2001, Order, is presently conducting "prudency hearings" regarding the transfer of utility transmission assets into the "Grid Florida" Transco, along with conducting an attendant rate case. These prudency hearings are restricted to the transfer of these assets into the "Grid Florida" Transco alone and not into a larger Southeastern RTO model. Since most State and local Commissions are unsure of the value of the transmission assets in a future competitive wholesale market structure under a system-wide RTO, they feel it is necessary to conduct proceedings to insure that retail customers receive "full" or "optimum" value for their assets upon their transfer.

- Fourth, almost all of the Southeastern States have held hearings and decided that restructuring or "retail competition" at this time is not in the public interest in their respective States. This present opposition to retail competition has been "hardened" by the recent market problems with retail competition in California. This Southeastern philosophy regarding restructuring is quite different from the Northeast and Midwest regions where the overwhelming majority of States in those regions either have or plan to have retail competition in the next one to two years. In their Motions for Rehearing most of the Southeastern State either believe or suspect that the Commission's call for a single Southeastern Regional RTO will usurp their state jurisdiction over retail transmission rates and force the States into "restructuring". The North Carolina Commission in their motion for rehearing specifically ask FERC for clarification whether: "[It] intends to assert jurisdiction over the transmission component of (North Carolinas) bundled electric service and [whether] ... the Applicants would retain authority over planning service to native load customers". is purporting to unbundle wholesale and retail transmission rates and truly force States into retail restructuring.[66] The Alabama Commission asserted:

> "[A]n RTO can lead to retail access by stripping away the efficiencies and advantages of a well run integrated system. Having lost the efficiencies for integrated system, Alabama might prematurely be faced into retail competition ... in order to attempt to regain a portion of these lost efficiencies through a competitive market. It is not at all clear perhaps even doubtful that the overall efficiency gain due to competition would outweigh the offset of losses from removing our current regulated system. The APSC believes that retail choice in any form is a State prerogative and the Commission should not undertake any actions that would infringe on a States jurisdiction to make this decision.[67]

Other State Commission's such as Georgia, North Carolina, South Carolina, and Mississippi have also voiced concerns that the Commission's attempt to identify separate transmission costs will unbundle retail rates and "force" States to retail competition.

Recognizing that the resolution of these critical issues, as with the process of forming a single RTO in the Southeast, will extend well beyond the 45 days allocated for this mediation process, the mediation team urged the plan proponents of both the Collaborative Governance and the SeTrans models to ensure that State Commissions would be provided an opportunity for meaningful input in the day-to-day decision making process or governance structure of the RTO platform. The Mediation Team, following

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[66] See North Carolina PUC (NCPUC) Motion for Rehearing, August 13, 2001. Docket # 0108150423-1 Mississippi PSC (MPSC), Motion for Rehearing August 13, 2001, Docket #0108150423-1 Alabama PSC (APSC), Motion for Rehearing, August 13, 2001, Docket #0108150423-1.

[67] APSC, Motion for Rehearing, p.5.

discussions with a number of State Commissioners and mediation participants, suggested to the plan sponsors that the State Commissions be given consideration of a direct advisory role to the Independent Board of the Southeastern RTO, through a separate State Commission Advisory Group. These suggestions for Advisory Group participation, as well as State Commission involvement with the "Stakeholder process," will allow the State Commissions to have meaningful involvement and an ability to protect the interests of rate payers regarding rates and reliability. Further, because of the importance of ensuring that state regulatory commissions of the affected states continue to have the opportunity to have input into the process, I am recommending that regardless of the RTO model adopted by the Commission as the platform for the Southeast Power Grid RTO that the Commission continue to encourage and utilize a collaborative process which accommodates both stakeholder and state utility commission input.

V. FINAL RECOMMENDATIONS

In an effort to provide the Commission with the most complete and accurate information possible from this intense forty-five day mediation effort, both the **Collaborative Governance Model** (representing a consolidation and evolution of some of the best aspects of the GridFlorida, GridSouth and Entergy models) and the **Independent Systems Administrator Model** (representing a convergence and evolution of some of the best aspects of the model proposed in Southern's filings), along with the comments of the more than 200 market participants who actively participated in this mediation effort (captured by owner classification "sector summaries" as noted herein above) have been presented to the Commission for consideration in this report.

As previously explained, while both models are a "work in progress" and require further Commission attention with respect to key aspects of Order 2000 RTO characteristics and core functions; it is the opinion of the undersigned Administrative Law Judge that of the two models the **Collaborative Governance Model** is better developed and more clearly in compliance with the requirements of Order 2000 based on a "best practices" analysis of other RTOs which have received Commission approval and prior Commission precedent with respect to the current filings. In response to the Commission’s direction, and in order to achieve the broadest general support not only from generators and marketers, but from other market participants as well, the proponents of the **Collaborative Governance Model** have compromised on a number of points initially contested in their respective RTO proceedings, notwithstanding the fact that many of their initial positions already have been sustained in prior Commission orders. For the reasons discussed in the body of this Report, this Administrative Law Judge recommends that the Commission consider adoption of the **Collaborative Governance Model** to the fullest extent possible consistent with the requirements of Order 2000 and the public interest in order to completely capture the many benefits going forward that this model has to offer. In this regard, it is important to note that the model represents a delicate balance of compromise and is presented as a fully integrated proposal. This delicate balance of compromise could be jeopardized were one or more of its constituent elements to be materially changed. Instead, it is recommended that the Commission consider adoption of the **Collaborative Governance Model** to the fullest extent possible consistent with the requirements of Order 2000 and the public interest, and order that any remaining unresolved issues be addressed through a continued stakeholder process.

While it is the opinion of this Administrative Law Judge that the **Collaborative Governance Model** represents a reasonable compromise that attempts to address the sometimes conflicting needs and desires of the market participants and other regional stakeholders, because a complete consensus among the plan sponsors and the more than 200 stakeholders that participated in this mediation effort was not reached, it will be incumbent upon the Commission to provide the parties with further guidance with respect to its determination of which of the two models best meets the Commission's expectations as a platform for the Southeast Power Grid RTO. In point of fact, one of the things that the parties did reach consensus on was the need to have the Commission make this critical determination as soon as practicable, using the negotiated product of this collaborative process to the fullest extent possible consistent with the requirements of Order 2000 and the best interests of the public. Absent clear Commission endorsement of its preferred model, impasse will continue with the parties polarized to their respective models, the progress of the parties in reaching the significant coalition compromises reflected in this Mediation Report will not be recognized, and a significant window of opportunity for reaching a sustainable RTO model will have been closed. Simply put, the public interest will not be served by further delay in building the infrastructure necessary for an effective Southeast RTO.

Participant response to this mediation, although often described as "arduous" and "intense", was very positive. As previously noted, approximately 200 market participants representing diverse stakeholder interests throughout the Southeast RTO footprint attended and fully engaged in this collaborative effort for the full forty-five days provided for by the Commission's July 112th Orders. Their comments and feedback included:

"It was a refreshing break to have a disciplined forum which not only allowed everyone's voice to be heard, but encouraged everyone to listen, consider other stakeholder's perspectives and push for solutions. This is how all market policy discussions should ideally work. "

"We have seen more progress in the last month than in the previous 10 years."

The parties in this mediation have worked in good faith to understand and accommodate each other’s concerns and goal, as a result, this mediation has led to many broad compromises on a wide range of issues in a very short period of time which have not been fully developed; accordingly, both models represent a "work in progress" with many issues that remain to be addressed. Because of the importance of ensuring that all stakeholders, including state regulatory commissions of the affected states, continue to have the opportunity to have input into the process, I am recommending that regardless of the model adopted by the Commission as the Southeast Power Grid RTO platform that the Commission continue to encourage and utilize a collaborative process which accommodates both stakeholder and state utility commission input.

Many market participants want the Commission to continue to play a substantial role in further collaborative processes urging that the Commission, through appropriate decisional Staff or an assigned Administrative Law Judge, should provide the venue for meetings, assist in setting the timetables and agendas, supervise drafting assignments, and ensure full participation of all interested parties (including state regulatory authorities) and market sectors to assure an effective and meaningful collaborative process which is inclusive for all stakeholders. I feel that the parties can, and should, continue this collaborative effort without Commission intervention except to the extent that it may be necessary and appropriate in response to specific Commission Orders.

This Mediation Report is submitted to ensure the timely accomplishment of the Commission's directives and, more specifically, to obtain Commission review of the two proposed models or "outlines" for the formation of the single Southeast Power Grid ("SPG") platform which have resulted from this collaborative mediation process to date. It is recommended that the parties be directed to reconvene within fifteen (15) days of the Commission's Order adopting its preferred model or "outline" for the Southeast Power Grid RTO and directed to submit within forty-five (45) days thereafter a joint proposal for implementation of that model with respect to all of the characteristics and core functions mandated by Order 2000.

VI. CONCLUSION

The highly sensitive information contained in this Mediation Report is being submitted to the Commission in accordance with the provisions of Rule 606 (g) and/or the agreement of the parties. It is my recommendation that this information be treated in accordance with the provisions of Rule 606 (e) for the purpose of ensuring that comments filed in response to the Mediation Report will not be admissible in evidence against any participant who objects to its admission and to ensure that any discussion of the parties with respect to the information contained in this Mediation Report is not subject to discovery or admissible in evidence.

I also recommend that the Commission adopt the provisions of Rule 602 (f) for the purpose of permitting the parties who have been actively engaged in this mediation proceeding an opportunity to file comments to this Mediation Report. While I have made every effort to the summarize the mediation process, the substance of both the Collaborative Governance and Independent Systems Administrator models, and the essence of the market participant responses to the models, we covered many highly complicated and sensitive issues in a short period of time. Permitting the parties to file comments to the Mediation Report not later than 20 days after the filing of this Report will ensure that every participant has had a full opportunity to be heard by the

Commission on these important issues without undue delay to the process. However, I recommend against permitting the filing of reply comments as this may prove counterproductive to the collaborative nature of this mediation process.

Bobbie J. McCartney
Administrative Law Judge/Mediator