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FPL

June 9, 2015

VIA E-Tariff
Kimberly D. Bose, Secretary
Nathaniel J. Davis Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: **Florida Power & Light Company**
Docket No. ER13-104-____
(Order No. 1000 Further Regional Compliance Filings)

Dear Ms. Bose and Mr. Davis:

Yesterday on June 8, 2015, Florida Power & Light Company ("FPL") attempted to make its compliance filing pursuant to Order No. 1000 of the Federal Energy Regulatory Commission ("Commission" or "FERC"),[1] 18 C.F.R. § 35.28(c), the Commission's April 7, 2015 Order on Rehearing and Compliance ("April Order"),[2] and the Commission's April 24, 2015 Notice of Extension of Time in this proceeding,[3]

Due to E-Tariff submittal issues, FPL was not able to make its compliance filing yesterday. After resolving the E-Tariff filing issues, FPL is submitting its compliance filing today.

Respectfully submitted,

/s/ Gunnar Birgisson
Gunnar Birgisson
Senior Attorney
NextEra Energy Inc.
(202) 349-3494

Attorney for Florida Power & Light Company

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[1] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 (2011), order on reh'g and clarification, 139 FERC ¶ 61,132 (2012) ("Order No. 1000-A"), *order on reh'g and clarification*, 141 FERC ¶ 61,044 (2012) ("Order No. 1000-B"), *aff'd sub nom. South Carolina Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (Order Nos. 1000, 1000-A, and 1000-B collectively referred to as "Order No. 1000," "Order," or "Final Rule").

[2] *Tampa Electric Co., et al.*, 151 FERC ¶ 61,013 (2015).

[3] *Tampa Electric Co., et al.*, Notice of Extension of Time, Docket Nos. ER13-80-003 *at al.* (Apr. 24, 2015).

Duke Energy Florida, Inc.
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Florida Power & Light Company
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Washington, D.C. 20004

Orlando Utilities Commission
100 W. Anderson St.
Orlando, Florida 32801

June 8, 2015

Via eTariff
Honorable Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: **Duke Energy Florida, Inc.**
Docket No. ER13-86-____
Florida Power & Light Company
Docket No. ER13-104-____
Orlando Utilities Commission
Docket No. NJ15-04-001
(Order No. 1000 Further Regional Compliance Filings)

Dear Ms. Bose and Mr. Davis:

Pursuant to Order No. 1000 of the Federal Energy Regulatory Commission ("Commission" or "FERC"),[1] 18 C.F.R. § 35.28(c), the Commission's April 7, 2015 Order on Rehearing and Compliance ("April Order"),[2] and the Commission's April 24, 2015 Notice of

[1] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 (2011), *order on reh'g and clarification*, 139 FERC ¶ 61,132 (2012) ("Order No. 1000-A"), *order on reh'g and clarification*, 141 FERC ¶ 61,044 (2012) ("Order No. 1000-B"), *aff'd sub nom. South Carolina Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (Order Nos. 1000, 1000-A, and 1000-B collectively referred to as "Order No. 1000," "Order," or "Final Rule").

[2] *Tampa Electric Co., et al.*, 151 FERC ¶ 61,013 (2015).

Extension of Time in this proceeding,[3] Duke Energy Florida, Inc. ("DEF"),[4] Florida Power & Light Company ("FPL"), and Orlando Utilities Commission ("OUC"), hereby provide further Order No. 1000 regional compliance filings. Tampa Electric Company ("TEC") is simultaneously filing a separate transmittal letter for its compliance filing in response to the April Order, which contains the same explanations of the changes being made in all the compliance filings, but also addresses certain issues unique to TEC's compliance filing.[5] DEF, FPL, OUC, and TEC are collectively the "Florida Sponsors."

The Florida Sponsors are Transmission Providers within the Florida Reliability Coordinating Council, Inc. ("FRCC") transmission planning region, and consist of three investor-owned public utilities in Florida (DEF, FPL, and TEC) and two large municipal utilities (OUC and JEA (formerly Jacksonville Electric Authority)). DEF, FPL, TEC and OUC (referenced as the "Florida Filing TPs" in this letter) are submitting further regional compliance filings under Order No. 1000. Although JEA is not submitting a filing, JEA has a conforming Open Access Transmission Tariff ("OATT").

The common tariff language being filed herein by the Florida Filing TPs, including the identical language filed separately by TEC, is intended to comply with the requirements of the April Order, which addressed the Florida Filing TPs' November 2014 compliance filings. The changes proposed herein were developed through extensive collaborative efforts by the Florida Sponsors, and vetted and reviewed through an interactive and public stakeholder process. As discussed in the filing, the Florida Filing TPs propose tariff revisions best suited to meet the requirements of the April Order and the objectives of Order No. 1000.

While the Florida Filing TPs are submitting this common transmittal letter and certain common attachments, the Florida Filing TPs are individually submitting the relevant revised provisions to their respective OATTs through eTariff to comply with the Commission's filing requirements. Thus, the Clean and Marked Tariffs Attachments will differ slightly for each Florida Filing TP.

I. STRUCTURE OF THIS FILING

The tariff changes proposed by the Florida Filing TPs are described in this transmittal letter and contained in the clean and redline versions of their respective tariffs. Their respective

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[3] *Tampa Electric Co., et al.*, Notice of Extension of Time, Docket Nos. ER13-80-003 *at al.* (Apr. 24, 2015).

[4] DEF shares a single Joint OATT with two of its affiliates, which Joint OATT is found in the eTariff database of Duke Energy Carolinas, LLC ("DEC"). As a result, DEC is identified as a co-applicant by the eTariff software.

[5] TEC's transmittal letter is largely identical to this transmittal letter, and references to "Florida Sponsors" in this letter include TEC although TEC is not a signatory to this letter.

proposed tariff language appears in the OATT Attachment Ks of FPL, OUC, and TEC, and in the OATT Attachment N-2 of DEF (referred to herein as "Attachment Ks").

The purpose of the filing is to comply with the directives of the April Order, which the Florida Sponsors have organized by task categories, consistent with the approach taken in the prior compliance filings for the FRCC transmission planning region.

Section II sets forth the directives of the April Order, organized by task category and paragraph reference(s) in the April Order, followed for each category by a discussion of how the proposed tariff language complies with the April Order. Section II also discusses the stakeholder process undertaken by the Florida Filing TPs in response to the Commission's directives.

Section III contains a general waiver request.

II. COMPLIANCE WITH DIRECTIVES, BY TASK CATEGORY

Task 1 – Consideration of Transmission Needs Driven by Public Policy Requirements—Regional

***Directive* (P 35):**

> While it is reasonable to require a stakeholder proposing a transmission need driven by public policy requirements to submit any information in the four categories that is available to that stakeholder, Florida Parties may not reject a proposed transmission need driven by public policy requirements merely because a stakeholder does not submit all the information. We therefore reject Florida Parties' proposal to revise their Attachment Ks so that a stakeholder "must" rather than "should" identify the four categories of information when proposing a transmission needs driven by public policy requirements. Accordingly, we direct Florida Public Utility Parties . . . to revise their OATTs to state that when a stakeholder proposes a transmission need driven by public policy requirements for consideration, the description of the need "should" include the 4 categories of information.

***Compliance*:**

In compliance with the Commission's directive, the provision addressing stakeholders' opportunity to submit a transmission need driven by a public policy requirement has been amended to state that stakeholders "should" provide the requested four categories of information. As proposed, section 11.1 now specifies that a stakeholder's description of such a transmission need "should" provide the requested information. Thus, a transmission need would not be rejected only because some of the requested information could not be provided.

Task 2 – Consideration of Transmission Needs Driven by Public Policy Requirements—Local

***Directive* (P 39):**

> Florida Parties propose that a stakeholder must identify four categories of information when proposing a transmission need driven by public policy requirements at the local level but, as we discuss in the previous section of this order, requiring a stakeholder to submit information about other entities' potential transmission needs, which may not be available to a particular stakeholder, creates a barrier to stakeholder submissions that is inconsistent with the requirement in Order No. 1000 that public utility transmission providers adopt procedures to "allow all stakeholders to bring forth any transmission needs that they believe are driven by Public Policy Requirements." Therefore, we direct Florida Public Utility Parties to . . . revise their OATTs to state that when a stakeholder proposes a transmission need driven by public policy requirements for consideration in the local transmission planning process, the description of the need "should" include the four categories of information.

***Compliance*:**

In compliance with the Commission's directive, the Florida Filing TPs propose to revise section A of Appendix A to their Attachment Ks to clarify that stakeholders "should" supply the requested information regarding transmission needs driven by a public policy requirement, but are not required to do so. Thus, stakeholders identifying a transmission need driven by public policy requirements are still required to submit a written description of the need, but a transmission need would not be rejected only because the requested information was not available to the stakeholder providing a written description of the need.

Task 3 – Financing through "Any Approved Rates"

***Directive* (P 45):**

> We also accept Florida Public Utility Parties' agreement in response to FMPA/Seminole, to make changes to account for cooperative or municipal utility rates and therefore direct Florida Public Utility Parties to file, within 30 days of the date of issuance of this order, further compliance filings revising their Attachment Ks to allow transmission developers to provide a description of financing through any approved rates.

***Compliance*:**

In response to the Commission's directive, the Florida Filing TPs propose to modify the Project Developer Qualification Criteria in Appendix 3 to account for the financing that cooperative or municipal utility developers may receive for their projects. The proposed language in section 1.A.1 in Appendix 3 states that a project developer must provide a description of any financing obtained for its previously-developed projects through "any approved rates." This is broader than the previous language, which only provided for financing under rates approved by FERC or a state regulatory agency. This change addresses the concern that the developer qualification criteria did not account for cooperative or municipal utilities whose rates are set by their owner-members.

Task 4 – FRCC Board Facilitation of Project Sponsors/Developers Collaboration on a CEERTS Project

***Directive* (P 59):**

> [W]e reject Florida Parties' proposal to delete the provisions in their Attachment Ks that provide for the FRCC Board, upon request, to facilitate an opportunity for project sponsors/transmission developers to collaborate with each other to determine how each of the transmission developers may share responsibility for portions of the CEERTS project. The proposed deletions are outside of the scope of the previous compliance directive. The Commission previously accepted these provisions, and we find that it is not necessary for Florida Parties to remove them to implement their proposal to choose among competing transmission developers for a CEERTS project sponsored by a non-developer. Accordingly, we direct Florida Public Utility Parties to submit . . . further compliance filings to restore the provision.

***Compliance*:**

In the Florida Filing TPs' prior compliance filing, the Florida Filing TPs had removed from section 1.2.10 of their Attachment Ks a process by which the FRCC Board would provide an opportunity for collaboration in the event there were multiple project developers for the same CEERTS project. In compliance with the Commission's directive in the April Order, the Florida Filing Parties have restored that prior language to section 1.2.10.C, thereby providing an opportunity for the various competing project developers of a single CEERTS project to collaborate with each other to determine how each may share responsibility for portions of the CEERTS project(s). This process remains voluntary and the FRCC Board would only facilitate this collaboration between prospective project developers if requested to do so. In the event that the project developers agree on coordinated development of the CEERTS project, the FRCC Board would select those developers to develop the CEERTS project. If the prospective developers cannot agree, the FRCC Board will proceed to select a project developer for the CEERTS project in the manner specified in their Attachment Ks.

Task 5 – Clarify the Timeline for Stakeholder Comments

***Directive* (P 60):**

> We also find that Florida Parties have partially complied with the requirement to clarify the timeline for the evaluation process and final selection of transmission projects in the regional transmission plan for purposes of cost allocation so that it can occur within the proposed two-year transmission planning cycle and to provide more detail about when the referenced FRCC Board meetings will occur. While the proposed changes to the length of time various steps in the process timeline will take would allow the process to be completed by the end of the two-year cycle . . . without a deadline for stakeholder comments on the FRCC Planning Committee's technical analysis report, the proposal would allow the evaluation process to be delayed indefinitely. Thus, without a deadline for stakeholder comments, the proposal does not fully comply with the requirement to clarify the Attachment Ks so that that the process will be completed within the proposed two-year time frame. In particular, Florida Parties propose that the FRCC Board's review of the FRCC Planning Committee's technical analysis report will take two to three months, but they also propose that the FRCC Board's review will not begin until after the FRCC Board receives comments on the technical analysis report from stakeholders. . . . Accordingly, we direct Florida Public Utility Parties to submit . . . further compliance filings to revise their Attachment Ks to provide a deadline for stakeholders to submit comments on the FRCC Planning Committee's technical analysis report. This deadline must provide stakeholders with sufficient time to provide meaningful input on the report for the FRCC Board to consider during the FRCC Board's review and also allow the evaluation process and final selection of transmission projects in the regional transmission plan for purposes of cost allocation to occur within the proposed two-year transmission planning cycle.

***Compliance*:**

The Florida Filing TPs' Attachment Ks provide numerous opportunities for stakeholder input, but as noted in the April Order, the proposed tariff language does not specify a deadline for stakeholder comments on the FRCC PC's technical analysis report, which will develop CEERTS project information, validate the CEERTS project information and analysis provided by the sponsor, and provide a recommendation to the FRCC Board. The prior absence of a deadline for stakeholder comments was not likely to lead to an indefinite delay in the decision of the FRCC Board on the FRCC PC's technical analysis report. However, in compliance with the Commission's directive and to avoid any future confusion on this issue, the Florida Filing TPs propose to revise section 1.2.7.C of their Attachment Ks to state that the CEERTS sponsor and any interested stakeholders will have 15 days to provide written comments on the FRCC PC technical analysis report, starting from the date when the FRCC PC report is provided to the FRCC Board. This will provide certainty regarding when comments must be submitted, and ensure that the FRCC Board benefits from those comments and can consider them when reviewing the report and determining whether the CEERTS project should proceed in the evaluation process. In addition, this deadline will not delay the timeline for consideration of proposed CEERTS projects because the 15-day comment period is within the two-to-three month period that the FRCC Board has to consider the FRCC PC report. Thus, the FRCC Board will have anywhere from one and a half to two and a half months to reach a decision following the submission of comments from the CEERTS sponsor and stakeholders.

Task 6 – Evaluation of Transmission Needs Driven by Public Policy

***Directive* (P 71):**

> Florida Parties may not at the evaluation stage determine, after identifying a transmission need driven by public policy requirements for which a transmission solution is required, that potential transmission solutions to address the transmission need will not be evaluated. We therefore reject Florida Parties' verification proposal in its entirety because Florida Parties do not comply with the requirement to describe how the benefits of a CEERTS project to address transmission needs driven by public policy requirements will be verified other than by relying on confirmation of sufficient transmission service commitments and because their verification proposal is inconsistent with the already accepted process to identify transmission needs driven by public policy requirements for which transmission solutions will be evaluated. Accordingly, we direct Florida Public Utility Parties to revise their Attachment Ks to remove in its entirety the proposed language that would require identified project beneficiaries to verify the CEERTS public policy benefits of a transmission project being evaluated for potential selection in the regional transmission plan for purposes of cost allocation.

***Compliance*:**

In compliance with the Commission's directive, the Florida Filing TPs propose to remove in its entirety the language in section 1.2.9.B.2 of their Attachment Ks providing a process in which the FRCC PC would work with the purported beneficiaries of a proposed CEERTS public policy project to verify that the identified needs exist and that the project could satisfy those needs. The Florida Filing TPs have also modified section 1.2.9.B.2 to cross-reference the identification and verification of the transmission needs driven by public policy requirements that is provided for in section 11.1 of their Attachment Ks and was already accepted by the Commission. Under section 11.1, the FRCC PC will use any description of transmission needs driven by public policy requirements provided by stakeholders, as well as additional information collected by the FRCC PC, to make a decision as to whether a public policy requirement is driving a transmission need for which a solution is required. Those verified needs are then incorporated into the FRCC's regional planning efforts. In this manner, the provisions of section 11.1 will provide the means to evaluate the submitted public policy requirements that may be driving transmission needs. The Florida Filing TPs understand that, as specified in P 334 of Order No. 1000-A, during the section 11.1 process for identifying transmission needs driven by public policy requirements, the FRCC is authorized to identify which parties are subject to the public policy requirements and whether such parties need a transmission solution to meet those requirements.[6]

Task 7 – Identification of Consequences of CEERTS Projects on Other Transmission Planning Regions

***Directive* (P 93):**

> [W]e reject Florida Parties' proposed provision to address the directives in the Second Compliance Order with respect to Regional Cost Allocation Principle 4. We direct Florida Public Utility Parties to submit, within 30 days of the date of issuance of this order, further compliance filings to (1) revise their Attachment Ks to provide that the regional transmission planning process will identify the consequences of a transmission facility selected in the regional transmission plan for purposes of cost allocation for other transmission planning regions, such as upgrades that may be required in another region and (2) address whether the FRCC region has agreed to bear the costs associated with any required upgrades in another transmission planning region and, if so, how such costs will be allocated within the FRCC region.

***Compliance*:**

In response to the Commission's directive, the Florida Filing TPs are proposing changes to their Attachment Ks to more closely track the requirements of Regional Cost Allocation Principle 4. Under Cost Allocation Principle 4 (paralleled by P 93 of the April Order) the FRCC transmission planning region must identify the consequences of CEERTS projects on other planning regions, including the need for upgrades.[7] In compliance with these requirements, the Florida Filing TPs propose to revise section 1.2.9.F to explain that if a CEERTS project is selected, the FRCC will identify the potential reliability impacts of that CEERTS project on other transmission planning regions, including possible upgrades in those regions, and then evaluate those impacts with the transmission owners in the neighboring region. Cost Allocation Principle 4 as well as P 93 of the April Order also require that the FRCC transmission planning region state whether it will bear the costs associated with any upgrades that may be necessary in

[6] *See* Order No. 1000-A at P 334 ("[T]he process for identifying transmission needs driven by Public Policy Requirements can identify what parties are subject to the Public Policy Requirements and whether such parties have a need for a transmission solution to meet those requirements.").

[7] Order No. 1000 at P 657 ("[T]he transmission planning process in the original region must identify consequences for other transmission planning regions, such as upgrades that may be required in another region . . . .").

that other planning region.[8] The Florida Filing TPs address this in section 9.4.6 of their Attachment Ks by stating that the FRCC Region will not bear the costs associated with such upgrades and will therefore not include the costs of those upgrades in the CEERTS project costs that are allocated within the FRCC transmission planning region. Because the FRCC Region will not bear these costs, the Florida Filing TPs need not explain how those costs would be allocated in the FRCC Region.

The Florida Filing TPs believe this approach is not only compliant with the two directives in the April Order, but also provides the most flexibility for resolving the impacts of CEERTS projects on other regions within the limitations of Cost Allocation Principle 4, which neither permits the FRCC transmission planning region to involuntarily allocate the costs of such upgrades to the applicable external region nor requires the FRCC transmission planning region to assume the costs of such upgrades. To make clear that nothing in the proposed tariff language limits how beneficiaries of a CEERTS project in the FRCC region, the CEERTS project sponsor or developer, the FRCC itself, or the transmission owners in the external region may choose to resolve the identified impacts, the Florida Filing TPs have included a sentence in section 9.4.6 stating that "However, nothing in this Attachment K prevents the beneficiaries or project sponsor of a CEERTS project that causes the need for upgrades in another region from voluntarily negotiating a resolution of the project impacts with the transmission owner(s) in the other region." Accordingly, sections 1.2.9.F and 9.4.6 allow these parties to address those impacts in a variety of ways, including, for example: the external transmission owners voluntarily paying for the upgrades, the CEERTS project sponsor paying for the upgrades, the external transmission owners mitigating the impact so as to avoid the need for upgrades, the project sponsor mitigating the impact to avoid the need for upgrades, or the parties proposing the regional project as an interregional project. In short, the proposed language provides the maximum flexibility in addressing the issue of possible upgrades needed in neighboring transmission planning regions as a result of CEERTS projects in the FRCC transmission planning region without limiting who can resolve those impacts or how those impacts should be resolved.

Task 8 – New CEERTS Project Replacing an Existing CEERTS Project

***Directive* (P 117):**

> However, we find that Florida Parties have not complied with the requirement to specify that, if a regional transmission project displaces a different regional transmission project that was previously selected in the regional transmission plan for purposes of cost allocation, the portion of the costs of the newly proposed more efficient or cost-effective regional transmission project associated with the benefits calculated using the costs of the displaced regional project will be allocated to the enrolled transmission providers that were allocated costs for the

[8] *Id.* ("[I]f the original region agrees to bear costs associated with such upgrades, then the original region's cost allocation method or methods must include provisions for allocating the costs of the upgrades among the beneficiaries in the original region . . . .") (emphasis added).

> displaced regional transmission project in accordance with the regional cost allocation method. . . . Therefore, we direct Florida Public Utility Parties to submit . . . further compliance filings to specify in their Attachment Ks that, if a regional transmission project displaces a different regional transmission project that was previously selected in the regional transmission plan for purposes of cost allocation, the portion of the costs of the newly proposed more efficient or cost-effective regional transmission project associated with the benefits calculated using the costs of the displaced regional project will be allocated to the enrolled transmission providers that were allocated costs for the displaced regional transmission project in accordance with the regional cost allocation method. We also accept Florida Parties' offer to include in their Attachment Ks a hypothetical example of the cost allocation process for displaced transmission projects and direct them to include those revisions in the further compliance filings.

***Compliance*:**

In compliance with the Commission's directive, the Florida Filing TPs have clarified the provisions of section 1.2.9.C.1 of their Attachment Ks to explain the process by which CEERTS costs will be allocated when a newly-proposed CEERTS project would replace a CEERTS project that was included in the most recent FRCC Board-approved transmission plan. As explained in the revised section, "[i]f a newly-proposed CEERTS project would displace a previously-approved CEERTS project, the portion of the costs of the newly-proposed CEERTS project associated with the benefits calculated using the costs of the displaced previously-approved CEERTS project would be allocated to the enrolled transmission providers that were allocated the costs for the previously-approved CEERTS project."

In addition, the Florida Filing TPs have also included an additional hypothetical example (Example 4) in Appendix 4 to their Attachment Ks, to provide additional clarity regarding the cost allocation process followed when an enrolled transmission provider has a CEERTS project displaced by a CEERTS project.

Task 9 – Clean-Up Revisions

***Directive* (P 144-45):**

> We share FMPA/Seminole's concerns regarding errors in the individual tariffs, such as the misplaced comma in section 1.2.9.B.2 and failing to insert the word enrolled before "transmission provider" in every instance. In addition to the errors FMPA/Seminole point out, we note that Tampa Electric's Attachment K as filed in eTariff is missing numerous sections . . . Additionally, Florida Power & Light's eTariff filing includes some mislabeled sections, misaligned margins resulting in the first few words in each section to be missing, and a "K" that was marked for deletion in the redline version, but still legible in the eTariff version. Finally, Florida Power & Light's eTariff is also missing several sections in which the section numbers have changed or other ministerial changes . . . Therefore, we

> direct Florida Public Utility Parties to . . . correct these errors. . . . Additionally, we note there are several other errors in the Florida Parties' clean and redline versions of the tariffs attached to their respective filings, such as language being missing, mis-marked accepted as the filed rate, or mis-marked as newly proposed language. While these issues are not present in the versions filed in eTariff, which are considered the rate on file, we note that Florida Parties should be careful to ensure that their next set of compliance filings do not have these types of ministerial errors in the redline and clean versions.

***Compliance*:**

In compliance with these directives, the Florida Filing TPs have adopted appropriate minor revisions throughout their Attachment Ks, including the addition of "enrolled" before "transmission provider" whenever the reference to the enrollment status of a transmission provider is appropriate. The Florida Filing TPs have also introduced various minor, non-substantive corrections, including punctuation and formatting changes, in order to address the concerns in the April Order, including the stakeholder concerns on this issue in the April Order.

The Florida Filing TPs note that TEC is filing a separate transmittal letter to address in greater detail the eTariff concerns identified in P 144 of the Commission's order that apply to it specifically.

Task 10 – Stakeholder Input on Proposed Changes

***Directive* (P 146):**

> We are also concerned by Florida Public Utility Parties' apparent objection to allowing stakeholders to provide input on proposed changes to their Attachment Ks to comply with Order No. 1000 prior to the changes being filed. The Commission expected public utilities to work with stakeholders to develop their proposals to comply with Order No. 1000. Thus, Florida Parties should allow stakeholders to provide input into any proposed changes prior to those changes being filed in the next compliance filings.

***Compliance*:**

In developing the instant compliance filing, the Florida Filing TPs conducted an interactive stakeholder process to provide an opportunity for interested stakeholders to review and comment on the proposed tariff language of the Florida Filing TPs and for the Florida Filing TPs to consider those comments.

On May 6, 2015, each of the Florida Filing TPs posted to the public FRCC website their proposed tariff changes, as well as a matrix identifying the compliance directives from the April Order and the corresponding tariff sections where the changes were proposed. Interested stakeholders were invited to provide written comments by May 18th. Written comments were received from two stakeholders, and both sets of comments were publicly posted on the FRCC website. On May 6, 2015, the Florida Filing TPs also invited interested stakeholders to participate by WebEx in a May 27, 2015 meeting to discuss the proposed tariff changes and stakeholder comments. The stakeholder meeting was conducted as scheduled and attended by representatives from four stakeholders: Seminole Electric Cooperative, Inc., the Florida Municipal Power Agency, Lakeland Electric and Calpine Corporation. The tariff changes proposed in this filing reflect many of the written comments received from the stakeholders in the FRCC transmission planning region, as well as the discussion during the May 27th stakeholder meeting.

III. REQUEST FOR WAIVER

The Florida Filing TPs are making this filing in compliance with the Commission's regional directives in Order No. 1000. By making this filing in compliance with that Order, the Florida Filing TPs believe that they have hereby satisfied the applicable Commission requirements. The Florida Filing TPs respectfully request waiver of any Commission regulations (including filing regulations) or requirements that are not specifically addressed in this filing. Additionally, the Florida Filing TPs recognize that some of the proposed changes, particularly language clean-ups, clarifications, and changes responsive to previously unidentified stakeholder concerns with accepted language, could be construed to fall under section 205 of the FPA. They thus seek waiver of eTariff and other filing requirements, to have this filing also treated as a section 205 filing to the extent necessary. Because the requested effective date is January 1, 2015, a waiver of the 60-day notice period is requested.

IV. LIST OF ATTACHMENTS

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

(a) A Clean Tariff Attachment for posting in eLibrary (Attachment A)

(b) A Marked Tariff Attachment for posting in eLibrary (Attachment B)

V. CONCLUSION

For the foregoing reasons the Florida Filing TPs respectfully request that the Commission accept the filed tariff provisions.

Sincerely,

Duke Energy Florida, Inc.
/s/ Jennifer L. Key
Jennifer L. Key
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Florida Power & Light Company

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Orlando Utilities Commission
/s/Derek A. Dyson
Derek A. Dyson
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Attachments

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document and attachments to be served on those parties on the official service lists compiled by the Secretary in these proceedings.

Dated at Washington, D.C. this 8th day of June, 2015.

/s/ *Gunnar Birgisson*
Gunnar Birgisson
Senior Attorney
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ATTACHMENT B

ATTACHMENT K

TRANSMISSION PLANNING PROCESS

Transmission Provider plans for the existing and future requirements of all customers of Transmission Provider's transmission system in a coordinated, open, comparable, non-discriminatory and transparent manner both at the local and regional level. The Transmission Planning Process described herein includes Transmission Service for Transmission Provider's Native Load Customers, Network Customers, Firm Point-to-Point Transmission Customers, and Generator Interconnection Service for Interconnection Customers. The Transmission Planning Process is intended to provide transmission customers the opportunity to interact with the transmission planning personnel of the Transmission Provider in order for transmission customers to provide timely and meaningful input into the development of the transmission plan. Transmission Provider's Transmission Planning Process works in conjunction with and is an integral part of the *Florida Reliability Coordinating Council's ("FRCC") Regional Transmission Planning Process* (reference the FRCC website for this document[1]) which facilitates coordinated planning by all transmission providers, owners and stakeholders within the FRCC Region.

The FRCC is one of the North American Electric Reliability Corporation ("NERC") Regional Reliability Organizations, with responsibility for maintaining grid reliability in Peninsular Florida, east of the Apalachicola River. This region is electrically unique because it is a peninsula and is tied to the Eastern Interconnection only on one side. FRCC's members include investor owned utilities, cooperative utilities, municipal utilities, a federal power agency, power marketers, and independent power producers. The FRCC Board of Directors has the responsibility to ensure that the *FRCC Regional Transmission Planning Process* is fully implemented. The FRCC Planning Committee ("FRCC PC"), which includes representation by all FRCC members, directs the FRCC Transmission Working Group and any other supporting group, in conjunction with the FRCC Staff, to conduct the necessary studies to fully implement the *FRCC Regional Transmission Planning Process*. The descriptions of the *FRCC Regional Transmission Planning Process* set forth herein summarize the elements of that process as they relate to Transmission Provider and the principles of the Final Rule in Docket No. RM05-25-000.

The Florida Public Service Commission ("FPSC") is an integral part of the planning process by providing input, guidance, regulatory oversight and decision-making under this process. Additionally, the FPSC conducts workshops on an annual basis to review the transmission and generation expansion plans for Florida. The FPSC, under Florida law, has the authority to ensure an adequate and reliable electric system for Florida. As set forth below, Transmission Provider's Transmission Planning Process is a seamless process that fully integrates both the local and regional transmission planning and is designed to satisfy the following principles, as defined in the FERC Final Rule in Docket No. RM05-25-000: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects. Descriptions of the *FRCC Regional Transmission Planning Process* are contained herein as they relate to Transmission Provider's Transmission Planning Process.

End Notes:

1. The FRCC posts on its website at https://www.frcc.com all of the FRCC documents referenced in this Attachment K. This provides flexibility for the FRCC to change the URL addresses for individual FRCC documents without requiring the modification of tariff language.

Section 1 Coordination

1.1 Transmission Provider consults and interacts directly with its customers in providing transmission service and generator interconnection service as well as with its neighboring transmission providers, on a regular basis. A transmission customer may request and/or schedule a meeting with Transmission Provider to discuss any issue related to the provision of transmission service at any time. Transmission Provider consults and interacts with its customers any time during the study process that either the transmission customer or the Transmission Provider deem necessary and/or at various stages of the planning process (e.g., Scoping Meeting, Feasibility, System Impact and Facilities Studies). An open dialogue between the transmission customer and the Transmission Provider takes place regarding customer needs. This interaction and dialogue between the customer and Transmission Provider are further described under the Local Transmission Network Planning Process as set forth in Appendix 1 to this Attachment K. Topics such as load growth projections, planned generation resource additions/deletions, new delivery points and possible transmission alternatives are discussed. This dialogue is intended to provide timely and meaningful input and participation of customers during the early stages of development of the transmission plan. Additionally, the transmission customer shall have an opportunity to comment at any time during the evaluation process and/or when study findings (Feasibility, System Impact and Facilities Studies) are communicated by the Transmission Provider to the customer. Transmission Provider communicates with its neighboring transmission providers on a regular basis, and Transmission Provider facilitates communication and consultation between its customers and its neighboring transmission service providers/owners, specifically, if during the transmission service study process, a neighboring system's facilities are identified as being affected. This coordination process continues in a seamless manner at the local as well as the regional level, leading to each Transmission Provider providing an initial transmission plan which, when consolidated, becomes the initial regional transmission plan. The initial transmission plan submitted to the FRCC by the Transmission Provider, which results from the Local Transmission Network Planning Process as set forth in Appendix 1 to this Attachment K, will be posted by the FRCC in accordance with the FRCC Regional Transmission Planning Process (reference link to Initial Plans on the FRCC website). This initial transmission plan is reviewed by the FRCC as well as all interested transmission customers/users. The Transmission Provider relies on the FRCC Committee process to finalize its initial transmission plan as submitted to the FRCC. In addition to transmission customers/users being provided timely and meaningful input and participation during the planning process with the Transmission Provider, the transmission customers/users are also given an additional opportunity to raise any issues, concerns or minority opinions that they believe have not been adequately addressed by any Transmission Providers' initial transmission plan submittal during the FRCC review process. This FRCC review process normally commences shortly after the submittal of the Ten Year Site Plans to the FPSC on April 1 of each year. Once issues raised by interested stakeholders are addressed, including consideration of proposed "Cost Effective or Efficient Regional Transmission Solutions" ("CEERTS") projects as set forth in section 1.2 below, the FRCC PC approves the proposed regional transmission plan and presents it to the FRCC Board for approval. Upon approval by the Board, which is expected in February of each year, the FRCC sends the final regional transmission plan to the FPSC. Unresolved issues may be resolved under the Dispute Resolution Procedures in Appendix 5.

1.2 CEERTS Projects

1.2.1 This section 1.2 sets forth provisions for consideration of proposed CEERTS projects in the regional transmission planning process in which Transmission Provider participates and applies to reliability, economic and public policy regional transmission projects. As discussed above, the FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The process results in a Board-approved regional plan. The biennial transmission planning process, in which CEERTS projects are identified, evaluated, and considered for regional cost allocation, contains several steps in which the FRCC Board is kept informed and must act in order to keep the process moving forward. The FRCC Board typically meets at least four times per year. If a regular meeting of the Board is not scheduled within the timeframes specified for the evaluation of a CEERTS project, special meetings of the Board will be called by the Chair, as needed, in order to meet the scheduled milestones for CEERTS project evaluation within the biennial transmission planning process timeline.

As set forth herein, the Transmission Provider, in collaboration with other transmission providers, FRCC staff, and other FRCC members, shall identify and evaluate whether there are more efficient or cost-effective regional transmission solutions to regional transmission needs relative to the transmission facilities in the initial regional transmission plan. The regional analysis shall utilize the standards, criteria, rules, tools, data, models, methods and studies of the local transmission plans, as delineated in Appendix 1, supplemented as necessary for the regional analysis as set forth herein. The regional analysis shall determine if there is a solution meeting CEERTS project criteria under section 1.2.3.

The regional analysis shall include consideration of potential transmission solutions to transmission needs driven by public policy requirements, as such needs are identified pursuant to section 11. The provisions for stakeholder involvement and input in the regional transmission plan, and ability to propose CEERTS projects on their own initiative, as set forth in this section 1.2, are fully applicable to potential transmission solutions to transmission public policy needs driven by public policy requirements.

1.2.2 Any entity desiring to propose a CEERTS project for regional cost allocation must submit such a CEERTS project to the FRCC no later than June 1st of the first year of the biennial regional projects planning cycle. The entity proposing a CEERTS project is referred to herein as the project sponsor. The project sponsor for a CEERTS project need not be the project developer for that project.

In addition to the right of individual entities to submit potential CEERTS projects, Transmission Provider shall participate with other transmission providers and other interested entities, through the FRCC PC, in the identification and evaluation of potential CEERTS projects for submission. The FRCC PC, or a designated subcommittee thereof, shall proactively seek out potential CEERTS projects from its analysis of the most recent Board-approved plan. This will occur during the period February through April of the first year of the biennial regional projects planning cycle. The general steps of the process are as follows:

A. Gather all relevant information relating to the most recent Board-approved plan (e.g., Final Project Information Form, approved Long Range Study, early project suggestions from interested entities); and request and collect all necessary supplemental information from transmission providers and other entities (e.g., project details and cost estimates for projects identified for potential displacement, list of potentially feasible projects not selected in the initial regional transmission plan).

B. Analyze the current plan information to identify potential opportunities for CEERTS projects. Seek justification for remedies that do not have projects planned, and synergies with the planned projects that potentially could be modified, combined, or accelerated for a more cost effective or efficient regional transmission solution. The analysis will include comparative load flow studies to evaluate various potential transmission CEERTS projects. For example, comparative load flow studies will be run to identify and evaluate potential CEERTS projects that could displace transmission projects in the initial regional transmission plan.

   1. If a potential CEERTS project is identified that addresses a regional reliability or economic transmission need(s) for which no transmission projects are currently planned, an analysis will be performed to identify local and/or regional alternative transmission project(s) which would also fully and appropriately address the same transmission need(s). These local and/or regional alternative transmission project(s) will be identified through comparative load flow studies. The alternative project(s) will be used to determine the Total Estimated Alternative Project Cost Benefit in the CEERTS Project Cost-Benefit Analysis described in section 1.2.9.C.

   2. If a potential regional public policy transmission need has been identified for which no transmission projects are currently planned and for which no CEERTS project has otherwise been submitted for evaluation, an analysis will be performed to identify a potential

CEERTS project that would satisfy that regional public policy transmission need in a least-cost manner by evaluating various potential transmission project alternatives.

C. Develop potential CEERTS project alternatives and solicit project sponsorship from enrolled transmission providers and other entities which may have an interest in sponsoring potential CEERTS projects.

1. A potential CEERTS project developed by this process will contain the following minimum set of transmission project information:

a) General description of the transmission facilities being proposed;

b) General path of the transmission lines; and

c) Transmission systems that would interconnect with the potential CEERTS project.

2. The FRCC shall post a notice on its website of any potential CEERTS projects identified through this process. Notice would be posted by May 1 of the first year of the biennial regional projects planning cycle to provide time for meeting sponsorship requirements by June 1.

3. Each identified potential CEERTS project will require at least one sponsor in order to be submitted to the FRCC for consideration. Multiple sponsors of the same project will be considered joint sponsors and shall equally share the required $100,000 deposit unless the sponsors otherwise mutually agree to a different sharing of the deposit. Potential CEERTS projects identified in this process shall not have competing sponsors for the same project. An entity that is not a sponsor or joint sponsor of a potential CEERTS project shall not be eligible to be a developer of that project unless the sponsors discontinue development of that project.

4. The sponsor or joint sponsors shall submit the potential CEERTS project for consideration in the first year of the biennial regional projects planning cycle.

1.2.3 To be eligible for approval by the FRCC Board for inclusion in the regional plan, a proposed CEERTS project must meet these threshold criteria:

A. Be a transmission line 230 kV or higher and 15 miles or longer; or be a substation flexible AC transmission system ("FACTS") device, e.g., series compensation or static var compensator, designed to operate at 230 kV or more; and

B. Be materially different from~~than~~ projects already in the regional plan. For purposes of this section, the FRCC will consider a CEERTS project to be materially different from another CEERTS project if it displaces a different local project or projects or is not considered a minor adjustment to an existing local or CEERTS project that it is displacing. Minor adjustments could include changes in equipment size, different terminal bus arrangement, or a slight change in route.

Local transmission facilities located solely within a T~~t~~ransmission P~~p~~rovider's footprint (e.g. Control Area) that are not selected in the regional transmission plan for purposes of cost allocation cannot qualify as CEERTS projects. Such facilities are the responsibility of the Transmission Provider to meet reliability needs and/or other obligations within its retail distribution service territory or footprint.

1.2.4 A CEERTS project submittal must include the following elements (to be provided in the context of the most current FRCC Board-approved regional transmission plan):

A. Those project sponsors that do not also intend to be a project developer must submit sufficient information related to the proposed CEERTS project that will permit the potential CEERTS project to be adequately considered within the FRCC regional transmission planning process. Below is the minimum set of information that must be submitted:

1. General description of the transmission facilities being proposed;

2. General path of the transmission lines; and

3. Transmission systems that would interconnect with the proposed CEERTS project.

B. Those project sponsors that intend to be the project developer shall so indicate and shall submit the following information:

1. Transmission project technical information:

a) Description of the transmission facilities being proposed (*e.g.*, voltage levels);

b) General path of the transmission lines; and

c) Interconnection points with the existing transmission system.

2. A cost estimate and a recommended in-service date for the project. A project developer may also submit a demonstration of its cost containment capabilities, including any binding agreement to accept a cost cap for the developer's cost of the transmission project if it is selected as a CEERTS project.

3. If the project sponsor is an incumbent, it must indicate which funding option set forth in section 9.4.5.A it intends to select.

4. A high-level summary of who will own, operate and maintain the CEERTS project, to the extent available.

C. A project sponsor may also submit any studies and analysis it performed to support its proposed CEERTS project, including the below:

1. Reliability impact assessment.

2. Load flow analysis that demonstrates performance utilizing the FRCC load flow model. The sponsor, if not an FRCC member, may obtain this model upon request from the FRCC ("Request for Florida Reliability Coordinating Council (FRCC) Transmission Information" document is posted on the FRCC website).

3. Identification of projects in the regional transmission plan that would be affected or avoided as well as any additional projects that may be required. A demonstration through a technical evaluation process that the CEERTS project is equal to or superior to avoided projects from the current regional transmission plan.

D. A deposit of $100,000 shall be submitted by the project sponsor at the time the project is submitted (*e.g.*, June 1st of the biennial regional projects planning cycle) for each CEERTS project. This deposit will be used for FRCC internal labor costs for analysis of the project as well as any out-of-pocket expenses such as for independent consultants (unexpended amounts shall be refunded, with interest, to the project sponsor). The actual costs incurred by the FRCC to analyze the CEERTS project will be borne by the project sponsor and the deposit will be trued up based on the documented cost of the analysis. An accounting of the actual costs of the CEERTS project analysis including an explanation of how the costs were calculated will be provided to the project sponsor after the analysis has been completed. Any disputes regarding the accounting for specific deposits will be addressed through the Dispute Resolution Procedures in Appendix 5.

1.2.5 During the 30-45 days following the submittals under section 1.2.2, the FRCC PC shall review the project sponsor submittals and ensure that they meet the threshold criteria in section 1.2.3 and the minimum requirements in section 1.2.4. If a submittal is incomplete, the FRCC PC shall inform the CEERTS sponsor in writing within 15 days after the next regularly scheduled FRCC PC meeting of the specific deficiency(ies), and the CEERTS sponsor shall be given an opportunity, within 30 days, to submit the information required for a complete submittal. This may be referred to as Step 1.

1.2.6 At the next FRCC Board meeting following the review in section 1.2.5, the FRCC PC shall provide an update to the FRCC Board related to all projects that have been submitted and deemed complete. The FRCC PC shall post this information on the FRCC website (subject to any posting restrictions to protect CEII or other confidential information). This may be referred to as Step 2. At that time, the FRCC PC shall also post on the FRCC website (subject to any posting restrictions to protect CEII or other confidential information) any determination that a proposed CEERTS project is not materially different from a project or projects already in the regional plan. Such posting will include an explanation of the basis for the determination that the proposed CEERTS project is not materially different.

1.2.7 During the succeeding three to five months following the FRCC Board meeting in section 1.2.6, for those CEERTS projects that cleared sections 1.2.3 through 1.2.5 above, the FRCC PC, together with an independent consultant, will conduct a technical analysis for the purpose of either developing CEERTS project information or validating CEERTS project information and analysis provided by the sponsor. Such analysis will be performed in a manner consistent with other technical analyses performed by the FRCC PC. This may be referred to as Step 3.

A. The development/validation process will either develop the needed CEERTS project parameters or validate the information and analysis provided by the sponsor. This analysis will examine the following:

1. Transmission project technical information:

a) Description of the transmission facilities being proposed (*e.g.*, voltage levels);

b) General path of the transmission lines; and

c) Interconnection points with the existing transmission system.

2. Load flow analysis that demonstrates adequate NERC Reliability Standards performance utilizing the FRCC load flow model;

3. Whether it can be demonstrated through a technical evaluation process that the CEERTS project is equal to or superior to avoided projects from the current regional transmission plan or equal to or superior to the alternative transmission project(s) that address(es) the same transmission need(s), which alternative must be identified

if there are no transmission projects currently planned for the relevant transmission need(s) (see section 1.2.2.B);

a) The FRCC PC shall verify that the proposed CEERTS project addresses transmission need(s) for which there are no transmission projects currently planned, and that the alternative project(s) to the CEERTS project could also meet such need(s). After the alternative project(s) are verified to meet such needs, the FRCC PC shall request that the entities responsible for the alternative project(s) provide cost information to the FRCC PC to be used in the FRCC PC's analysis;

4. Identification of projects in the regional transmission plan that would be affected or avoided as well as any additional projects that may be required.

a) The FRCC PC shall request that the entities responsible for the existing project(s) that could be impacted by the proposed CEERTS project, or entities who would be required to implement additional local projects provide cost information to the FRCC PC to be used in their analysis;

5. Cost estimate for the proposed CEERTS project; and

6. In-service date for the project.

B. The FRCC PC will also consider any proposed non-transmission alternatives on a comparable basis with the CEERTS project, as described in section 5.

C. The FRCC PC will provide the CEERTS sponsor ~~-~~and stakeholders an opportunity to review and provide input on a report that includes its findings from the technical analysis performed, and then the report will be provided to the FRCC Board with a recommendation as to whether the proposed CEERTS project should proceed to the next evaluation step in section 1.2.8 below. The CEERTS sponsor and stakeholders shall be given 15 days to ~~an opportunity to also~~ provide written comments on the report to the FRCC Board following the date on which the FRCC PC provides the report and its recommendations to the Board.

1.2.8 Over a period of two to three months from receipt of the FRCC PC report and any comments on the report provided by the CEERTS sponsor and stakeholders pursuant to section 1.2.7.C, the FRCC Board will review the FRCC PC report and any comments received and determine if the CEERTS project should proceed to the next evaluation step as described in section 1.2.9 below. The CEERTS sponsor shall be invited to be present and participate in any FRCC Board meeting that addresses the FRCC PC report in order to answer questions and to present its views regarding the CEERTS project and the FRCC PC report. If a CEERTS sponsor does not agree with the FRCC Board's determination, then the Dispute Resolution Procedures in Appendix 5 are available for use by the CEERTS sponsor. This may be referred to as Step 4.

1.2.9 Over a period of two to four months from FRCC Board approval of the continuation of the CEERTS project evaluation in section 1.2.8, the process described below will be performed by the FRCC PC under the direction of the FRCC Board. This may be referred to as Step 5.

A. A meeting will be organized by the FRCC PC to provide the CEERTS sponsor an opportunity to fully describe its proposed CEERTS project. This meeting is the venue to fully discuss the CEERTS project, taking into account the technical analysis performed by the FRCC PC, as well as any potential revisions, including transmission technical aspects, transmission project costs, and affected projects. This meeting also provides the opportunity for potentially affected transmission providers to discuss these matters. If no developer is a sponsor of the proposed project, then this meeting also provides an opportunity for potential developers to express interest in being considered as the developer of the CEERTS project (if no entity expresses interest as the project developer then the project will not move forward and the projects in the regional plan that would have been avoided by the CEERTS project will remain in the regional plan). If multiple qualified project developers express an interest in developing a CEERTS project for which the sponsor does not plan to be the developer, then such developers must each submit, within the 30 days following the meeting held pursuant to this section 1.2.9.A, the project information identified in section 1.2.4.B.2 through 1.2.4.B.4 and these project developer proposals will be evaluated in the remainder of the steps identified in sections 1.2.9 and 1.2.10. This forum will enable the CEERTS project to be fully reviewed by all affected parties.

B. The FRCC PC will consider the proposed project in light of the criteria set forth in sections 1.2.7.A. and 1.2.7.B above and as set forth below.

1. A cost-benefit analysis must be performed in accordance with section 1.2.9.C for reliability/economic projects by an independent consultant. If the result of this analysis is a benefit-to-cost ratio of greater than 1.00, the CEERTS project will move forward in the process.

2. For a ~~proposed public policy~~ project proposed to meet a public policy transmission need that requires a solution, as verified by the FRCC PC under~~identified through the process set forth in~~ section 11~~ of Attachment K~~, the FRCC PC will determine whether the proposed CEERTS project meets the public policy transmission needs identified. There is no cost-benefit analysis performed,

except for the validation of the CEERTS project being the least-cost solution. The CEERTS project may be the only solution proposed, in which case it would be accepted in accordance with the project sponsorship model being used within the FRCC. However, in the event there are equally effective alternative CEERTS project solutions that have been proposed to satisfy the public policy transmission needs, then the least-cost CEERTS project would be selected.

~~The FRCC PC will work with the identified project beneficiaries to verify the CEERTS public policy project benefits by confirming: that the identified needs exist, the level (in MW) of such needs, and that such needs could be satisfied by the project. The FRCC PC and the project beneficiaries, who are enrolled transmission providers, will consult with the retail and/or wholesale customers to determine if the proposed CEERTS public policy project provides an opportunity to access resources that fulfill their state, federal, or local laws or regulation related to their public policy requirements and to confirm the quantity of megawatts of such access that is needed by such customers. The FRCC PC will then make a final determination and provide an explanation of why the CEERTS project does or does not provide an opportunity to satisfy the public policy needs based on an analysis of the information provided by the customers. If the benefits of the CEERTS public policy transmission project cannot be verified, then the public policy transmission needs may be resubmitted and reassessed in the next FRCC biennial planning cycle, if such needs remain. If the benefit of a CEERTS public policy project has been verified, then t~~The total estimated cost of the CEERTS public policy project is determined by the methodology set forth in section 1.2.9.C.4. ~~If the benefit of a CEERTS public policy project has been verified, then the project will move forward in the process.~~

C. CEERTS Project Cost-Benefit Analysis

An independent consultant will be retained to perform a cost-benefit analysis and will issue a written report of findings to the FRCC PC for sponsor and stakeholder review as set forth in section 1.2.9.D. The independent consultant will determine if the benefit-to-cost ratio, which is the sum of the "Total Estimated Avoided Project Cost Benefit," "Total Estimated Alternative Projects Cost Benefit" and "Total Estimated

Transmission Line Loss Value Benefit" divided by the "Estimated CEERTS Project Cost," is greater than 1.0.

Such analysis will consider estimated costs and benefits for the 10-year period of the planning horizon that is used to prepare the regional transmission plan under development at the time the analysis is prepared plus an additional, sequential 10-year period (the "20-year period"). Levelized annual costs and benefits to determine the appropriate revenue requirements will be used and deemed appropriate.

1. Total Estimated Avoided Project Cost Benefit

The Estimated Avoided Project Cost Benefit for each enrolled transmission provider in the FRCC that has one or more projects being displaced by a CEERTS project will be determined by the independent consultant in the below manner. ~~An enrolled transmission provider may include a CEERTS project developer whose CEERTS project~~A CEERTS project that was previously selected and included in the most recent Board-approved transmission plan may ~~would~~ be displaced by a ~~different~~newly-proposed CEERTS project. If a newly-proposed CEERTS project would displace a previously-approved CEERTS project, the portion of the costs of the newly-proposed CEERTS project associated with the benefits calculated using the costs of the displaced previously-approved CEERTS project would be allocated to the enrolled transmission providers that were allocated the costs for the previously-approved CEERTS project (see Appendix 4, Example 4 for a hypothetical example of this cost allocation process). ~~These displaced projects will include those projects that are currently in the transmission plan that are being displaced:~~

Each enrolled transmission provider that has one or more projects being displaced is considered a beneficiary of the proposed transmission facility(ies) and will develop an original installed capital cost estimate for each project being displaced and indicate in what year each such project would be projected to be in service.

The independent consultant will review each enrolled transmission provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate, depending on which will be used for further calculations, for each year that the displaced project would have been expected to be in service during the 20-year period, but for the CEERTS project. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the enrolled transmission provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements for each project will be determined using the average discount rate of enrolled transmission providers weighted by their total capitalization (Enrolled TP Discount Rate). Each enrolled t~~T~~ransmission p~~P~~rovider will provide its discount rate and total capitalization to the independent consultant for purposes of this calculation. Such net present value will be the "TP Estimated Avoided Project Cost Benefit" for ~~the~~each enrolled t~~T~~ransmission p~~P~~rovider's displaced project(s).

All such TP Estimated Avoided Project Cost Benefits will be summed to determine the Total Estimated Avoided Project Cost Benefit.

2. Total Estimated Alternative Projects Cost Benefit

The Estimated Alternative Project Cost Benefit for each enrolled transmission provider in the FRCC that has one or more alternative projects for which a CEERTS project addresses a need for which there are no transmission projects currently planned will be determined by the independent consultant in the below manner. These projects will include those alternative transmission projects to a CEERTS project that were identified under section 1.2.2.B.1:

Each enrolled transmission provider that has one or more alternative projects is considered a beneficiary of the proposed transmission facility(ies) and will develop an original installed capital cost estimate for each alternative project and indicate in what year each such project would be needed to be in service.

The independent consultant will review each enrolled transmission provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate, depending on which will be used for further calculations, for each year that the alternative project would have been expected to be in service during the 20-year period, but for the CEERTS project. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the enrolled transmission provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements for each project will be determined using the average discount rate of enrolled transmission providers weighted by their total capitalization (Enrolled TP Discount Rate). Each enrolled t~~T~~ransmission p~~P~~rovider will provide its discount rate and total capitalization to the independent consultant for purposes of this calculation. Such net present value will be the "TP Estimated Alternative Project Cost Benefit" for ~~the~~each enrolled t~~T~~ransmission p~~P~~rovider's displaced project(s).

All such TP Estimated Alternative Project Cost Benefits will be summed to determine the Total Estimated Alternative Project Cost Benefit.

3. Total Estimated Transmission Line Loss Value Benefit

The Total Estimated Transmission Line Loss Value Benefit is calculated for each enrolled transmission provider by the independent consultant as follows:~~.~~

The change in transmission losses caused by the CEERTS project will be determined by the FRCC PC.

The FRCC PC will run simulations of the approved transmission plan with all projects, adjusted (if necessary) to include the alternative transmission projects that were identified that would have been needed to satisfy a transmission need for which no transmission projects are in the current transmission plan (see section 1.2.2.B), to establish base transmission losses for each enrolled transmission provider represented in the plan over the planning horizon. Base case losses will be determined for the years during which the CEERTS project is expected to be in service during the planning horizon, under both peak and off-peak conditions.

The approved transmission plan will then be modified to (1) include a proposed CEERTS project; (2) remove all alternative transmission projects; and (3) adjust or remove any affected or avoided transmission projects in the approved transmission plan as well as add any additional projects that would be required (see section 1.2.7.A.4) (after verifying that all reliability requirements are met) with the appropriate in-service dates. The modified plan is then analyzed for losses. The CEERTS case losses are determined for each enrolled transmission provider represented in the plan for the years during which the CEERTS project is expected to be in service during the planning horizon, at both peak and off-peak conditions. Enrolled transmission providers with reduced losses are beneficiaries of the CEERTS project.

The change in losses for year 10 of the planning horizon will be held constant for years 11-20 of the 20-year period. The change in losses (whether negative or positive) in each year that the CEERTS project is in service for the 20-year period is determined for each enrolled transmission provider.

The value of the change in losses for each enrolled transmission provider will be determined by the independent consultant as follows:

The independent consultant will use fuel cost and heat rate data from the U.S. Energy Information Administration ("EIA") to value losses.

The net present value of the value of losses will be determined for each enrolled t~~T~~ransmission ~~P~~provider using the Enrolled TP Discount Rate.

Such net present value will be the "TP Estimated Transmission Line Loss Value Benefit."

The TP Estimated Transmission Line Loss Value Benefit for each enrolled transmission provider will be summed to determine the Total Estimated Transmission Line Loss Value Benefit.

4. Estimated CEERTS Project Cost

The Estimated CEERTS Project Cost is determined using the following formula:

Estimated CEERTS Project Cost = Estimated Developer Cost + Total Estimated Related Local Project Costs + Total Estimated Displacement Costs

The Estimated Developer Cost will be determined by the independent consultant as follows:

The developer of a CEERTS project will provide an original installed capital cost estimate for the developer's project and indicate which year the project is expected to be in service.

The independent consultant will review the developer's original cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate for the developer's project, depending on which will be used for further calculations, for the years during which the CEERTS project is expected to be in service during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the rates of return on equity approved by FERC for the developer or its affiliates (if any); commitments regarding incentive rates; proposed weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements will be determined using the Enrolled TP Discount Rate. The net present value of these estimated annual revenue requirements shall be the Estimated Developer Cost.

The Total Estimated Related Local Project Cost will be determined as follows by the independent consultant:

Each enrolled transmission provider that will need to construct a local project to implement the CEERTS project will develop an original installed capital cost estimate for each such related local project and indicate what year such project is projected to be in service.

The independent consultant will review the enrolled transmission provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate for each year that the local project is expected to be in service during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the enrolled transmission provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirement for each local project will be determined using the Enrolled TP Discount Rate. Such net present value will be the TP Estimated Avoided Project Cost for the displaced project.

All TP Estimated Related Local Project Costs will be summed to determine the Total Estimated Related Local Project Cost.

The calculation of Total Estimated Displacement Cost will be performed by the independent consultant as follows:

Any enrolled transmission provider that has incurred, or expects to incur, costs associated with a project that is being displaced by a CEERTS project will provide an accounting to the independent consultant as to the level of its actual and expected expenditure on any displaced projects and any planned mitigation of such expenditures. The independent consultant will review the displacement cost estimate. The independent consultant will estimate the level of displacement cost that the enrolled transmission provider that has expended funds on a displaced project will recover by assuming that the enrolled transmission provider will be permitted to recover 100% of such displacement costs. The independent consultant will calculate an annual transmission revenue requirement associated with the displacement cost estimate for each year so that the displacement costs would be recovered during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions and will describe such relevant factors and assumptions used in the report. The net present value of the estimated annual revenue requirements shall be calculated using the Enrolled TP Discount Rate. Such net present value will be the Estimated Displacement Cost.

All such Estimated Displacement Costs will be summed to determine the Total Estimated Displacement Cost.

D. The FRCC PC will provide the CEERTS sponsor and stakeholders an opportunity to review and provide input on a report that includes its findings from the cost-benefit analysis performed that determined how benefits and beneficiaries were identified and applied to a proposed CEERTS project. The report will then be provided to the FRCC Board with the FRCC PC's recommendation based upon its review as set forth above. For any CEERTS public policy project(s), t~~T~~his report will include ~~the results of the verification analysis for any CEERTS public policy project(s) with~~ an explanation of why the CEERTS project(s) does or does not provide an opportunity to satisfy the public policy need. The CEERTS public policy analysis is more completely described in section 11.1~~1.2.9.B~~. The CEERTS sponsor and stakeholders shall be given an opportunity to also provide written comments on the report to the FRCC Board. The CEERTS sponsor shall be invited to be present and participate in any FRCC Board meeting that addresses the FRCC PC report to answer questions and to present its views regarding the CEERTS project and the FRCC PC report.

E. The FRCC Board will review the FRCC PC report and any comments on the report that may be provided by the CEERTS sponsor and stakeholders and determine if the proposed CEERTS project is a more cost effective or efficient solution to regional transmission needs under applicable criteria in this section 1.2.9 and section 11.1.

~~E.~~F. If a CEERTS project is selected, the FRCC will perform analyses to determine whether the CEERTS project could potentially result in reliability impacts to the transmission system(s) in another transmission planning region. If a potential reliability impact is identified, the FRCC will coordinate with the public utility transmission providers in the other transmission planning region on any further evaluation. The evaluation may identify required upgrades in the other transmission planning region. The costs of those upgrades are addressed in section 9.4.6.

1.2.10 Over a period of two to three months following a decision that a CEERTS project should move forward under section 1.2.9, the following "Transmission Project Developer and Project Selection Process" will occur. This may be referred to as Step 6.

A. If the CEERTS project requires upgrades to an enrolled t~~T~~ransmission p~~P~~rovider's existing facilities that enrolled t~~T~~ransmission p~~P~~rovider retains a right-of-first refusal to build those portions of the CEERTS project. As used in this section the term "upgrade" means an improvement to, addition to, or replacement of a part of an existing transmission facility; the term does not refer to an entirely new transmission facility. Nothing herein affects an enrolled t~~T~~ransmission p~~P~~rovider's rights under state law with regard to its real property (including rights of way and easements).

B. If a single project sponsor is also the developer identified for a given CEERTS project, then that project sponsor/developer is accepted by default as the project developer eligible to use the regional cost allocation for that CEERTS project (subject to the qualifications review below). If there are different proposed CEERTS projects to address the same transmission need(s), then the CEERTS project will be selected based on the highest benefit-to-cost ratio as determined in section 1.2.9.C and once a project sponsor/developer's proposed CEERTS project is selected in the regional transmission plan, that project sponsor/developer will also be selected as the project developer eligible to use the regional cost allocation for that CEERTS project, subject to the project developer qualifications review. CEERTS projects proposed by a single qualified project developer and selected by the FRCC Board will not be assigned to a different project developer.

C. If there are multiple project developers for the same CEERTS project, then the FRCC Board will, upon request, facilitate an opportunity for the project sponsors/developers to collaborate with each other to determine how each of the project developers may share responsibility for portions of the CEERTS project(s). If agreement is reached, then these project sponsors/developers will be selected (subject to the qualifications review below). If there is no agreement, then the project developer for the CEERTS project will be selected based on the highest benefit-to-cost ratio as determined in section 1.2.9.C.

1.2.11 Project Developer Qualifications Review

A. Project developers (both incumbent and non-incumbent project developers) that are submitting for the first time a qualification application must submit the application and a deposit of $50,000 to the FRCC along with the information identified in the Qualification Criteria as set forth in Appendix 3 of this Attachment K. The deposit will be used by the FRCC Board to fund the internal FRCC labor cost for application review, which will be documented, and expenses for the independent consultant for the review described in the next section. Any unexpended amounts from the deposit, including interest, shall be refunded to the project developer. The transmission developer will be provided with an accounting of the actual costs and how the costs were calculated. Any disputes related to the accounting for specific deposits shall be addressed under the Dispute Resolution Procedures in Appendix 5. A project developer may be a joint venture or a partnership in which case a lead representative will be designated in the qualification application. Project developers that already have been found qualified after a review by the FRCC must submit an attestation to maintain their qualification as discussed in Appendix 3. If sufficient changes, as determined by the FRCC, have been identified in the attestation by a project developer which had previously been qualified, then a deposit of $10,000 to the FRCC will be required during the attestation review process. This deposit will be handled in a similar manner as described above for the initial project developer qualification review.

B. The FRCC Board will provide for the review of the submitted qualifications by an independent consultant. The consultant fees will be paid from the deposit made when a project developer qualification application is submitted. The consultant will make a recommendation to the FRCC Board as to whether the Qualification Criteria have been met. The FRCC Board shall make, on a non-discriminatory basis, a determination as to whether the Qualification Criteria have been met. If the FRCC Board determines that the Qualification Criteria have not been met, the FRCC Board will notify the project developer of the qualification deficiencies and provide a 30-day period for the project developer to cure the deficiencies. If a project developer does not agree with the FRCC Board's determination, then the Dispute Resolution Procedures in Appendix 5 are available for use by the project developer. The qualification process is a one-time process for each project developer, subject to the attestation review process provided for in Appendix 3.

C. The timeline for the project developer qualification review evaluation process is set forth below:

1. By January 1 of the first year of a biennial regional projects planning cycle, any potential developer that seeks to be qualified to develop CEERTS projects during this cycle must submit its qualifications to the FRCC. Biennial attestations also must be submitted at this time.

2. In January through March of the first year of a biennial regional projects planning cycle, FRCC shall coordinate the qualifications review.

3. By April 1 of the first year of a biennial regional projects planning cycle, the FRCC Board will inform developers that have submitted qualifications or attestations that they have either met the qualification criteria or the FRCC Board will identify deficiencies in the submitted qualifications/attestations.

4. From April 1 through April 30 of the first year of a biennial regional projects planning cycle, developers will have an opportunity to cure deficiencies and resubmit their modified qualifications/attestations.

5. From May 1 through May 31 of the first year of a biennial regional projects planning cycle, the FRCC Board shall reexamine the modified qualifications/attestations, make final determinations, and notify~~ies~~ developers, FRCC members and other stakeholders.

1.2.12 Approval and Certification after Conclusion of the Project Developer Determination and Qualifications Review

A. At the next FRCC Board meeting after successful completion of the items in sections 1.2.3 through 1.2.11 above, the FRCC Board will notify the project developer to proceed with the project as it has been approved for inclusion in the regional transmission plan. It is at this point that any transmission projects currently in the regional transmission plan that are being avoided due to the new CEERTS project will be removed from the regional transmission plan. The project developer(s) shall then proceed with obtaining the necessary approvals and/or permits required to construct, own and operate the project, including certification under the Transmission Line Siting Act.

1.2.13 The FRCC PC, under the oversight of the FRCC Board, will verify that all required reliability, operational, and property rights provisions listed below are in place, or reasonably planned for, after a CEERTS project is included in the regional transmission plan pursuant to section 1.2.12. The FRCC Board will monitor such elements and progress toward such elements in determining whether a CEERTS project has been delayed or abandoned.

A. All certification and other requirements under the NERC Standards and Rules of Procedure;

B. Implementation of communications and operational control features (e.g., requirements to follow instructions of the Reliability Coordinator, Balancing Authority and/or Transmission Service Provider);

C. Responsibility for operation and maintenance ("O&M"), including any plans to turn over O&M responsibilities to another entity; and

D. Acquisition of the property rights necessary to construct the CEERTS facilities, or a reasonable expectation of the ability to acquire such rights.

1.2.14 As identified in section 1.2.2, new CEERTS projects are to be submitted by June 1 of the first year of each biennial regional projects planning cycle. The technical evaluation of a new CEERTS project will occur within approximately 12 months concurrent with the evaluation of the initial FRCC regional transmission plan, and final approval will be achieved within 19 months. This time period may be shorter for some CEERTS projects, such as where the project developer has previously satisfied qualification criteria and/or the project is relatively small in scale. Following the evaluation steps identified in this section 1.2 for a newly proposed CEERTS project, a sponsor can expect the project to be analyzed with the regional transmission plan as a tentative project in the summer or fall of the following year. For the project to remain in the regional transmission plan, the remainder of the process must be completed. For example, a new CEERTS project that was proposed by June 1 in biennial year 1 would proceed through section 1.2.7 in the fall of biennial year 1 through the winter of biennial year 2. In the spring and summer of biennial year 2, the project would progress through the items in section 1.2.9 and be tentatively added to the regional transmission plan. Successful completion of the items in sections 1.2.10 through 1.2.12 would qualify the project for final approval in December of biennial year 2, roughly 19 months after it was initially proposed. This overall schedule provides a roadmap of the projected schedule for new CEERTS project evaluation, selection, approval and ultimate reflection in the regional transmission plan within the mandatory two year (biennial) planning cycle. A particular CEERTS project submittal may benefit from schedule flexibility or shortening of process steps depending on the project's nature or complexity, availability of qualified project developer(s), or other factors. In all cases, once a CEERTS project is submitted, the FRCC will keep all parties informed of the projected schedule for project evaluation. This CEERTS project evaluation process will fold into the overall regional transmission planning cycle, which will continue to be an annual process, that is, a regional transmission plan will continue to be developed each year. The inclusion of the CEERTS projects into the annual regional transmission plan will be in accordance with the process outlined above.

1.2.15 After a CEERTS project is approved for the regional transmission plan, the project developer shall submit to the FRCC PC a development schedule that sets forth the required steps necessary to develop and construct the project and the schedule that the developer will follow to satisfy each required step. Required steps include, but are not limited to, obtaining all regulatory approvals necessary to develop and construct the facility.

1.2.16 Status updates of a CEERTS project are required at any time when material changes to the project or schedule take place, or at least annually, and must include any revised cost estimate. If the cost estimate for a CEERTS project is substantially more than the cost estimate upon which the project was approved, the FRCC PC and FRCC Board may re-examine the cost effectiveness of the project.

1.2.17 If a CEERTS reliability-based project is abandoned by the developer the Transmission Provider(s) has a right of first refusal to complete the project to the extent it is located in the Transmission Provider's service territory. However, if the Transmission Provider decides not to complete the abandoned reliability-based CEERTS project and decides instead to propose an alternative CEERTS project, then other potential developers will be given an opportunity to propose an alternative CEERTS project to ensure that the reliability need is met. Developer evaluation and selection shall follow the steps above for a CEERTS project when first proposed. If a non-reliability-based CEERTS project is abandoned by the developer, other potential developers may offer to complete the project.

Developer evaluation and selection shall follow the steps above for a CEERTS project when first proposed.

1.2.18 If a delay in the completion of a CEERTS reliability-based project potentially would cause Transmission Provider or other NERC-registered entity to violate a Reliability Standard, the NERC-registered entity shall inform the FRCC as soon as it is aware of the possibility. The FRCC PC will re-evaluate the regional transmission plan to determine if the delay in the CEERTS project requires the evaluation of alternative solutions to ensure the relevant Transmission Provider or other NERC-registered entity can continue to meet its reliability and/or other service obligations. If the FRCC PC determines that the delay in the CEERTS project would adversely affect reliability (e.g., would cause a violation of one or more NERC reliability standards), the FRCC PC will initiate a process to evaluate solutions to address the reliability concerns. The transmission providers whose system(s) are affected by these reliability concerns will be given an opportunity to propose solutions that they would implement within their service territories or footprints to address these reliability concerns, and their proposals can be evaluated as possible CEERTS projects if such transmission providers agree. The FRCC PC will fully evaluate the original CEERTS project delay along with any proposals for alternate solutions and will make a determination on how to proceed in a timely manner to ensure that the FRCC regional transmission plan supports the adequate planning for a reliable transmission system for the FRCC region. Where possible, the review of a CEERTS project delay will be included within the biennial regional transmission planning cycle. However, if the FRCC PC determines that a CEERTS project delay needs to be evaluated outside of the biennial regional projects planning cycle, the FRCC PC will notify the members and establish a schedule for the evaluation process. The FRCC PC will follow similar steps that are identified in sections 1.2.9.C and 1.2.9.D to develop a report of the results of their evaluation and provide their findings to the FRCC Board for ultimate resolution.

1.2.19 The Transmission Provider retains the right to construct local transmission projects that are not subject to regional cost allocation to meet reliability needs and/or service obligations within its retail distribution service territory or footprint.

1.2.20 Nothing herein shall adversely affect the ability of Transmission Provider to comply with state and federal law, including its service obligations under the laws and regulations of the Florida Public Service Commission and its reliability obligations under section 215 of the Federal Power Act ("FPA").

1.3 The FRCC Regional Transmission Planning Process is intended to ensure the long-term reliability, economic and public policy needs of the bulk power system in the FRCC Region (see section 1.3 endnote). An objective of the FRCC Regional Transmission Planning Process is to ensure coordination of the transmission planning activities within the FRCC Region in order to provide for the development of a reliable and economically robust transmission network in the FRCC Region. The process is intended to develop a regional transmission plan to meet the existing and future requirements of all customers/users, providers, owners, and operators of the transmission system in a coordinated, open and transparent manner.

The FRCC obtains and posts transmission owners' 10-year expansion plans on the FRCC website. All transmission providers/owners provide their long-term firm transmission service requests and generator interconnection service requests to the FRCC in a common format. The FRCC consolidates all requests for coordination purposes, and posts the consolidated requests available for viewing by all FRCC members.

Section 1.3 Endnote: Nothing in the *FRCC Regional Transmission Planning Process* is intended to limit or override rights or obligations of transmission providers, owners and/or transmission customers/users contained in any rate schedules, tariffs or binding regulatory orders issued by applicable federal, state or local agencies. In the event that a conflict arises between the FRCC process and the rights and obligations included in those rate schedules, tariffs or regulatory orders, and the conflict cannot be mutually resolved among the appropriate transmission providers, owners, or customers/users, any affected party may seek a resolution from the appropriate regulatory agencies or judicial bodies having jurisdiction.

1.3.1 This coordinated *FRCC Regional Transmission Planning Process* offers many opportunities for transmission providers to interact with customers and neighboring systems during the development of the transmission plan. The schedule of committee and working group meetings related to transmission planning is posted on the FRCC website under *FRCC Calendar*.

FRCC meeting notices, meeting minutes and documents of FRCC PC and/or FRCC Board meetings in which transmission plans or related study results are exchanged, discussed or presented~~,~~ are distributed by the FRCC. Detailed evaluation and analysis of the transmission providers/owners plans are conducted by the FRCC Transmission Working Group ("TWG") and Stability Working Group ("SWG") in concert with the FRCC Staff. The TWG and SWG are further described below.

1.4 A general scope of the FRCC PC and the respective working groups related to transmission planning is described below. The scope of these committees is subject to change in the future in order to address evolving needs. The members of the FRCC PC and the working groups related to transmission planning are posted on the FRCC website under *FRCC Committees.* Contact with the FRCC PC and transmission working groups can be made through FRCC staff or through the chair of the respective committee or working group.

1.4.1 The FRCC PC promotes the reliability of the Bulk Power System in the FRCC, and assesses and encourages generation and transmission adequacy. The FRCC PC reports to the Board of Directors. Rules and procedures governing the FRCC PC are posted on the FRCC website under *Rules of Procedure for FRCC Standing*

Committees. Working Groups related to transmission planning reporting to the FRCC PC are described below.

1.4.2 The Transmission Working Group engages in active coordination of transmission planning within the FRCC Region under the direction of the FRCC PC , and performs the duties as required by the *FRCC Regional Transmission Planning Process*. Some of the responsibilities and objectives of the Transmission Working Group are: 1) Maintain, update and provide summer and winter database cases for the FRCC including the bulk power transmission and generation systems, projected loads and any facility additions for an eleven year period; 2) Put together the FERC Form 715 filing and EIA-411 for FRCC members, prepare State of Florida electrical maps, etc.

1.4.3 The Stability Working Group engages in the active coordination of transmission planning in the FRCC Region, assesses stability of the FRCC bulk electric system under various conditions, and provides support to the other FRCC working groups as needed. Some of the responsibilities and objectives of the Stability Working Group are: 1) Maintain and update a dynamic data base for the FRCC Region; this data base is coordinated with selected FRCC planning horizon power flow cases as required by NERC Multi-regional Modeling Working Group and other FRCC study needs; 2) Assess dynamic performance of the FRCC bulk power system in response to Category B, C and D contingencies which includes special protection systems, under frequency load shedding programs, oscillatory stability, disturbances involving separation, etc.

Section 2 Openness

2.1 Transmission Provider provides notice and schedules meetings with its transmission customers as deemed necessary by the transmission customer and/or Transmission Provider. Transmission Provider schedules meetings with its customers to interact, exchange perspectives or share findings from studies. Transmission Provider communicates and interacts with its transmission service customers on a regular basis to discuss loads, generation/network resource additions/deletions, new facility additions and upgrades, demand resource information, customer~~'~~s’ projections of future needs, and related subjects that have an impact on the provision of transmission service to a customer. Transmission Provider provides a status update to its customers on a regular basis or at any time, if requested by a customer. Additionally, Appendix 1 to this Attachment K describes the customer and Transmission Provider interaction in the flow diagram and outlines the steps of the Local Transmission Network Planning Process.

2.2 This openness principle is also incorporated in the *FRCC Regional Transmission Planning Process* by which the Transmission Provider participates, ~~in~~ along with other parties, in the committee and working processes at the FRCC as described below. The participants in the planning process at the FRCC are the sector representative of the FRCC PC~~Planning Committee~~. A list of representatives may be found on the FRCC website under the *FRCC PC~~lanning Committee~~ Member List.* The *Rules of Procedure for FRCC Standing Committees* document on the FRCC website describes the FRCC

PC~~Planning Committee~~ structure and processes as they relate to Organization Structure, Standing Committee Representation, Standing Committee Quorum and Voting, Duties of Officers and Representatives, General Procedures for Standing Committees, FRCC Representation on NERC Committees, Procedures of Minutes of Meetings and Conduct of the Meeting. Interested entities or persons may participate in the committees via participation within one of the identified sectors (Supplier Sector, Non-Investor Owned Utility Wholesale Sector, Load Serving Entity Sector (including municipals and cooperatives), Generating Load Serving Entity Sector, Investor Owned Utility Sector, and General Sector (this sector provides for any entity or individual's participation)). Moreover, at the FRCC regional level interested entities have an opportunity to raise any special requirements that they have and believe have not been addressed at the local level. For ease of reference, the FRCC quorum and voting provisions are shown in Appendix 2 of Attachment K.

2.2.1 The FRCC meeting dates are provided in the *FRCC Calendar* document on the FRCC website and the chairs and member representatives for the various committees are posted on the FRCC website under the *FRCC Committees*. The meeting agenda for the FRCC PC is normally provided two weeks prior to the meeting to the committee members.

FRCC meeting notices, meeting minutes and documents of FRCC PC and/or FRCC Board meetings in which transmission plans or related study results will be exchanged, discussed or presented, are distributed by the FRCC.

2.2.2 The FRCC developed the *FERC Standards of Conduct Protocols* for the *FRCC* document for the purpose of ensuring proper disclosure of transmission information in accordance with FERC requirements. The primary rule is that a transmission provider must treat all transmission customers, affiliated and non-affiliated on a non-discriminatory basis, and it cannot operate its transmission system to give a preference to any transmission customer or to share non-public transmission or customer information with any transmission customer. The rules also prevent transmission function employees from sharing with their merchant employees and certain affiliates non-public transmission information about the transmission provider's transmission system or any other transmission system, which is information that the affiliated merchant employee receiving the information could use to commercial advantage. Reference the *FERC Standards of Conduct Protocols for the FRCC* posted on the FRCC website.

2.3 Customer input is included in the early stages of the development of the transmission plans, as well as during and after plan evaluation processes. Detailed evaluation and analysis of the transmission providers'/owners' plans are conducted by the FRCC Transmission Working Group and Stability Working Groups under the direction of the FRCC PC. Such evaluation and analysis provides the basis for possible changes to the transmission providers'/owners' plans that could result in a more reliable and more robust transmission system for the FRCC Region. The FRCC PC meets on a regular basis, usually monthly, with two weeks~~'~~ prior notice.

2.4 The FRCC conducts the FRCC planning process in an open manner in such a way that it ensures fair treatment for all customers/users, owners and operators of the transmission system. Stakeholders have access to and participate in the FRCC planning process. The committees and working groups described in this document are stakeholder groups. The FRCC PC consists of six stakeholder sectors: Suppliers, Non-Investor Owned Utility Wholesalers, Load Serving Entities, Generating Load Serving Entities, Investor Owned Utilities, and General. The rules of procedure governing the FRCC PC in conducting the *FRCC Regional Transmission Planning Process* are posted under the *Rules of Procedure for FRCC Standing Committees* on the FRCC website. The FPSC is encouraged to and does participate in the *FRCC Regional Transmission Planning Process*.

2.5 The *FRCC Regional Transmission Planning Process* provides for the overall protection of all confidential and proprietary information that is used to support the planning process. A customer, user or other interested entity may enter into a confidentiality agreement with the FRCC and/or applicable transmission provider/owner, as appropriate, to be eligible to receive transmission information that is restricted due to Critical Energy Infrastructure Information ("CEII"), security, business rules and standards and/or other limitations. The procedure for requesting this type of information is delineated at the FRCC website under the *Request of CEII Data*.

Section 3 Transparency

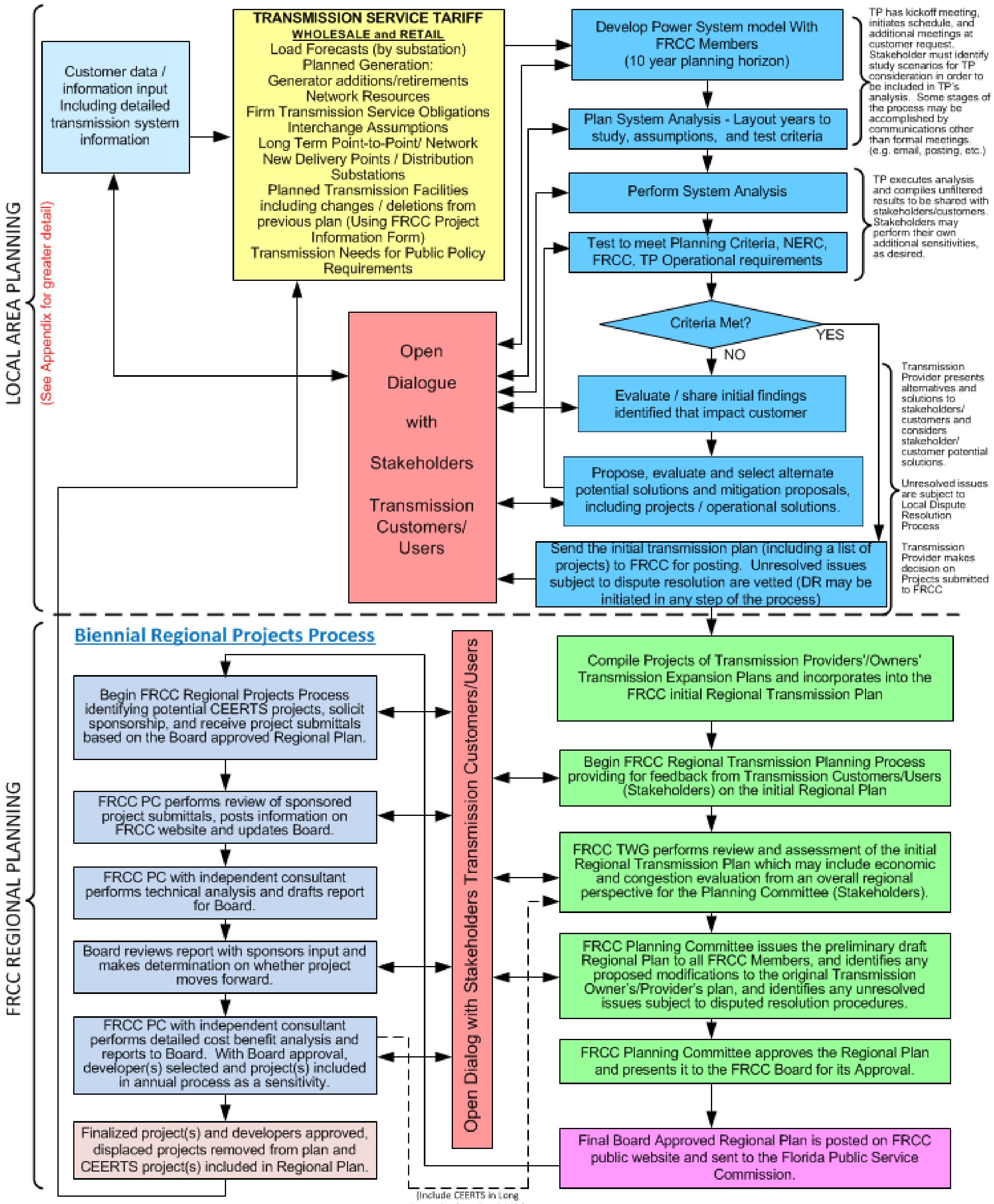
3.1 Transmission Provider plans its transmission system in accordance with the NERC and FRCC Planning Reliability Standards, along with Transmission Provider's own design, planning and operating criteria which it utilizes for all customers on a comparable and non-discriminatory basis. These standards/criteria are also referred to in the Transmission Provider's FERC Form 715. In addition, Transmission Provider makes available Facility Connection Requirements, Capacity Benefit Margin ("CBM") Methodology and other pertinent information used in the transmission planning process and posts this information on the Transmission Provider's OASIS website.

3.2 During the Transmission Provider's local area planning process the Transmission Provider utilizes the FRCC databanks which contain information provided by the Transmission Provider and customers of projected loads as well as all planned and committed transmission and generation projects, including upgrades, new facilities and changes to planned-in-service dates over the planning horizon, as the base case for Transmission Provider's studies. Transmission Provider makes available to a transmission service customer the underlying data, assumptions, criteria and underlying transmission plans utilized in the study process. Transmission Provider provides written descriptions of the basic methodology, criteria and processes used to develop plans. In order to get a better understanding, a transmission customer may inquire about the assumptions, data and/or underlying methods, criteria, etc. and the customer will be provided a response by the Transmission Provider's qualified technical representative. Dialogue during the study process is encouraged. The dialogue during the Transmission Provider's local area planning process between the Transmission Provider and customers involves discussions of the initial findings that affect customers, potential alternatives including feasibility of mitigating any adverse findings, and third party impacts.

Discussion of initial findings in areas of the system that affect customers is intended to communicate and validate with the customer issues or concerns identified by the Transmission Provider or conversely, issues not specifically identified by the Transmission Provider that may be of concern to the customers. As part of the process of identifying potential alternatives to mitigate any adverse issue or concern, the dialogue with the customer should facilitate the identification of the most effective solution. This dialogue during the different stages of the planning process provides for meaningful input and participation of transmission customers in the development of the transmission plan. The goal of this interaction between the Transmission Provider and customers is to develop a transmission expansion plan that meets the needs of the Transmission Provider and customer in a reliable cost effective manner. This planning process between the Transmission Provider and customers is described in the process flow diagram below and in the more detailed description of the Local Transmission Network Planning Process as set forth in Appendix 1 to this Attachment K.

3.3 An overview of the Transmission Provider's local area planning process and how it relates to the *FRCC Regional Transmission Planning Process* is shown in the flow chart below:

TRANSMISSION PROVIDER's (TP) LOCAL / REGIONAL COORDINATED TRANSMISSION NETWORK PLANNING PROCESS OVERVIEW



3.4 Once the results of the Transmission Provider's local area planning process are reflected in the *FRCC Regional Transmission Planning Process*, the FRCC seeks input and feedback from transmission customers/users for any issues or concerns that are identified and independently assesses the initial regional transmission plan from a FRCC regional perspective. A dialogue among the FRCC, transmission customers/users, and transmission owners/providers occurs to address any issues identified during this process. When the FRCC regional transmission plan has been approved by the FRCC PC, it is sent to the FRCC Board for approval. After the FRCC Board approves the FRCC regional transmission plan, it is posted on the FRCC website and sent to the FPSC. Additionally, the FRCC compiles all of the individual transmission providers'/owners' FERC Form 715~~'~~s within the FRCC region, including Transmission Provider's, and files all FERC Form 715~~'~~s for its members with the FERC on an annual basis.

3.5 Studies conducted pursuant to the *FRCC Regional Transmission Planning Process* utilize the applicable reliability standards and criteria of the FRCC and NERC that apply to the Bulk Power System as defined by NERC. Such studies also utilize the specific design, operating and planning criteria used by FRCC transmission providers/owners. The transmission planning criteria are available to all customers and stakeholders. Transmission planning assumptions, transmission projects/upgrades and project descriptions, scheduled in-service dates for transmission projects and the project status of upgrades will be available to all customers through the FRCC periodic project update process. The FRCC updates and distributes transmission projects/upgrades project descriptions, scheduled in-service dates, and project status on a regular basis, no less than quarterly. The FRCC also updates and distributes on a periodic basis the load flow data base. The FRCC publishes the individual transmission providers' system impact study schedules so that other potentially impacted transmission owners can assess whether they are affected and elect to participate in the study analysis. The FRCC planning studies are also distributed by the FRCC and updated as needed. All entities that have transmission projects/upgrades in the regional transmission plan shall provide updates on such projects at least annually.

3.6 The FRCC also produces the following annual reports which are submitted/available to the FPSC:

- The Regional Load and Resource Plan contains aggregate data on demand and energy, capacity and reserves, and proposed new generating unit and transmission line additions for Peninsular Florida as well as statewide.

- The Reliability Assessment is an aggregate study of generating unit availability, forced outage rates, load forecast methodologies, and gas pipeline availability.

- The Long Range Transmission Reliability Study is an assessment of the adequacy of Peninsular Florida's bulk power and transmission system. The study includes both short-term (1-5 years) detailed analysis and long-term (6-10 years) evaluation of developing trends that would require transmission additions or other corrective action. Updates on regional areas of interest and/or constraints (e.g., Central Florida) are also addressed.

Section 4 Information Exchange

4.1 Transmission Provider participates in information exchange on a regular and ongoing basis with the FRCC, neighboring utilities, and customers. Transmission customers are required to submit data for the planning process described in this Attachment K to the Transmission Provider in order for the Transmission Provider to plan for the needs of network and point-to-point customers. This data/information shall be provided by the transmission customer by no later than January 1 of each year. Such data/information includes load growth projections, planned generation resource additions/upgrades (including network resources), any demand response resources, new delivery points, new or continuation of long-term firm point-to-point transactions with specific receipt (i.e., source or electrical location of generation resources) and delivery points, (i.e., the electrical location of load or sink where the power will be delivered to), and planned transmission facilities. This data/information shall be provided over the 10 year planning horizon to the extent such information is known. Additionally, the transmission customer shall provide timely written notice of any material changes to this data/information as soon as practicable due to the possible effect on the transmission plan or the ability of the Transmission Provider to provide service.

4.2 The Transmission Provider utilizes the information provided in modeling and assessing the performance of its system in order to develop a transmission plan that meets the needs of all customers of the transmission system. The Transmission Provider exchanges information with a transmission customer to provide an opportunity for the transmission customer to evaluate the initial study findings or to propose potential alternative transmission solutions for consideration by the Transmission Provider. If the Transmission Provider and transmission customer agree that the transmission customer's recommended solution is the best over-all transmission solution then such solution will be incorporated in the Transmission Provider's plan. Through this information exchange process the transmission customer has an integral role in the development of the transmission plan. This process is described in greater detail in Appendix 1 to this Attachment K. Consistent with the Transmission Provider's obligation under federal and state law, and under NERC and FRCC reliability standards, the Transmission Provider is ultimately responsible for the transmission plan.

4.3 The FRCC TWG sets the schedule for data submittal and frequency of information exchange which starts at the beginning of each calendar year. Updates and revisions are discussed at the FRCC PC meetings by the members. This process requires extensive coordination and information exchange over a period of several months as the FRCC develops electric power system load-flow databank models for the FRCC Region. The models include data for every utility in peninsular Florida and are developed and maintained by the FRCC. The TWG is responsible for developing and maintaining power flow base cases. The FRCC power flow base case models contain the data used by the FRCC and transmission providers for intra- and inter-regional assessment studies, and other system studies. The models created also are the basis for the FRCC submittal to the

NERC Multi-regional Modeling Working Group ("MMWG"). TWG members support the data collection requirements and guidelines related to the accurate modeling of generation, transmission and load in the power flow cases. The data collected includes:

For power flow models:

- Bus data; (name, base voltage, type, area assignment, zone assignment, owner)
- Load data; (bus, MW, MVAR, area assignment, zone assignment, owner)
- Generator data; (bus, machine number, MW, MVAR, status, PMAX, PMIN, QMAX, QMIN, MVA base, voltage set-point, regulating bus)
- Branch data; (from bus, to bus, circuit number, impedances, ratings, status, length, owner)
- Transformer data; (from bus, to bus, to bus, circuit number, status, winding impedances, ratings, taps, voltage control bus, voltage limits, owner)
- Area interchange data; (area, slack bus, desired interchange, tolerance)
- Switched shunt data
- Facts device data

For dynamic stability models (in addition to power flow model data):

- Generator models; (turbine, generator, governor, exciter, power system stabilizers)
- Relay models; (distance, out of step, underfrequency)
- Special protection scheme models

For short circuit models (in addition to power flow model data):

- Zero and negative sequence impedances;

The databank models are compiled and incorporate load projections by substations, firm transmission services, and transmission expansion projects over the 10 year planning horizon. Transmission Provider utilizes the FRCC databanks which contain projected loads as well as all planned and committed transmission and generation projects, including upgrades, new facilities and changes to planned in-service dates over the planning horizon, as the base case for Transmission Provider's studies. These databanks are maintained by the FRCC Transmission Working Group and are updated on a periodic basis to ensure that the assumptions are current. Transmission Provider makes available to a transmission service customer the underlying data, assumptions, criteria and transmission plans utilized in the study process. If information is deemed confidential, Transmission Provider requires the customer to enter into a confidentiality agreement prior to providing the confidential information.

4.4 The FRCC maintains databanks of all FRCC members' projected loads and planned and committed transmission and generation projects, including upgrades, new facilities, and changes to planned in-service dates. These databanks are updated on a periodic basis. The FRCC maintains and updates the load flow, short circuit, and stability models. All of this above information is distributed by the FRCC, along with the FRCC transmission planning studies, subject to possible redaction of user sensitive or critical infrastructure information consistent with market and business rules and standards.

4.5 Any transmission developer that is not participating in the regional transmission planning process (and therefore not seeking regulated cost-of-service recovery) that proposes to develop a transmission project in the FRCC region shall provide to the FRCC PC and affected transmission providers in the FRCC region such information and data related to its proposed project that are necessary to allow the FRCC PC and affected transmission providers in the FRCC region to assess the potential reliability and operational impacts of the non-participant developer's proposed transmission facility on the transmission system in the region. That information should include: transmission project timing, scope, network terminations, load flow data, stability data, HVDC data (as applicable), and other technical data necessary to assess potential impacts.

The required information and data shall be provided with the transmission developer's interconnection request(s). Non-participant developers' transmission projects will not be included in long-term planning models or interconnected to the existing transmission system until and unless: 1) interconnection service has been requested of affected transmission provider(s); and 2) all interconnection studies have been completed.

Section 5 Comparability

5.1 This comparability principle is applied in all aspects of the transmission planning process including each of the respective principles in this Attachment K. Transmission Provider incorporates into its transmission plans on a comparable basis all firm transmission obligations, both retail and wholesale. The retail obligations consist of load growth, interconnection and integration of new network resources, firm power purchases and new distribution substations. Transmission Provider wholesale obligations are existing firm wholesale power sales, existing long-term firm transmission service including firm point-to-point and network (interconnection and integration of network resources), projected network load, generator interconnections, and new delivery points.

5.2 Transmission Provider plans for forecasted load, generation additions/upgrades which include network resources and new distribution substations associated with retail service obligations. A network transmission customer provides corresponding data as part of the provision of service, such as load forecast data, generation additions/upgrades including network resource forecast, new delivery points, and other information needed by the

Transmission Provider to plan for the needs of the customer. Both Transmission Provider and the transmission customers reflect their demand response resources within the information that is input within this planning process. The data required for planning the transmission system for both retail and wholesale customers is comparable. Transmission customers/users (retail and wholesale) accurately reflect their demand response resources appropriately in their load forecast projections. To the extent a customer/stakeholder has a demand response resource or a generation resource that is not incorporated into its submitted plans and such customer/stakeholder desires the Transmission Provider to specifically consider on a comparable basis such demand response resource or generation resource as an alternative to transmission expansion, or in conjunction with the Transmission Provider's transmission expansion plan, such customer/stakeholder sponsoring such demand response resource or generation resource shall provide the necessary information (cost, performance, lead time to install, etc.) in order for the Transmission Provider to consider such demand response resource or generation resource alternatives comparably with other alternatives. Any customer/stakeholder sponsoring a demand response resource or generation alternative should participate in the planning process. The Transmission Provider shall treat customer/stakeholder resources and its own resources on a comparable basis for transmission planning purposes. This comparability principle is also further described under the Local Transmission Planning Process as set forth in Appendix 1 to this Attachment K. The data/information is also provided to the FRCC for its use in databank development and analysis under the *FRCC Regional Transmission Planning Process*. These data requirements are generally communicated by OASIS, email, letter or combination thereof.

5.3 Transmission providers/owners submit to the FRCC their latest 10-year expansion plans for their transmission systems, which incorporate the transmission expansion needed to meet the transmission customer requirements, including a list of transmission projects that provides for all of the firm obligations based on the best available information. The FRCC compiles and distributes a list of projects distributed from the transmission providers/owners and updates the project status to keep the list current. FRCC compiles and distributes the transmission providers/owners' 10-year expansion plans. All transmission users and other affected parties are asked to submit to the FRCC any issues or special needs that they believe are not adequately addressed in the expansion plans.

5.4 Transmission providers that own or control or have been approved to own or control transmission facilities in the FRCC region may enroll in the FRCC regional planning process. These transmission providers must satisfy one of two enrollment criteria: (1) registered with NERC as a Transmission Service Provider or a Transmission Owner within the FRCC region; or (2) selected to develop a CEERTS project. Should a NERC-registered Transmission Service Provider or a Transmission Owner that owns or provides transmission service over facilities located adjacent to, and interconnected with, transmission facilities within the FRCC region provide an application to enroll in the FRCC regional planning process, such a request to expand the FRCC regional planning region will be considered by the FRCC. An entity may request enrollment in the planning process for purposes of regional cost allocation by submitting a written or email communication by authorized representative to the FRCC identifying that it is seeking to enroll. The FRCC will validate the request against the above criteria, provide a response back to the entity making the request in seven business days, and if the request is granted, which granting makes the enrollment effective, the FRCC will request that the Transmission Provider make the necessary OATT change to add the entity to the below list of enrolled transmission providers with a requested effective date of the date that the request was granted. Transmission providers that do not enroll in the regional planning process will not be obligated to pay the costs of transmission facilities that would otherwise be allocable to them under Order No. 1000, nor will their projects be eligible for Order No. 1000 cost allocation. If a developer that has been selected to develop a CEERTS project and is not also a Transmission Service Provider or Transmission Owner within the FRCC region abandons such project and that developer does not have any other approved CEERTS project, the FRCC will notify the developer that steps will be taken to remove it from the current list of enrolled transmission providers. Below is the current list of enrolled transmission providers:

Duke Energy Florida, Inc.

Florida Power & Light Company

JEA

Orlando Utilities Commission

Tampa Electric Company

Florida Municipal Power Agency

Seminole Electric Cooperative, Inc.

City of Tallahassee, Florida

5.5 A non-public utility transmission provider choosing to withdraw its enrollment in the FRCC regional planning process may do so by providing written notification of such intent to the Transmission Provider. A non-public utility's withdrawal shall be effective as of the date the notice of withdrawal is provided to the Transmission Provider. The withdrawing non-public utility will be subject to regional cost allocations, if any, that were approved in accordance with this Attachment K during the period in which it was enrolled and was determined to be a beneficiary. Any withdrawing non-public utility will not be allocated costs for regionally cost-allocated projects approved after its termination of enrollment becomes effective. Any withdrawing non-public utility will continue to be able to recover costs allocated to the beneficiaries of CEERTS projects that were allocated pursuant to this tariff until it has recovered such costs.

5.6 If a non-public utility transmission provider withdraws, the Transmission Provider shall submit to FERC an update to the list of enrolled transmission providers with a proposed effective date for the relevant tariff record that reflects the effective date of the withdrawal.

Section 6 Dispute Resolution

6.1 If a dispute arises between a transmission customer and the Transmission Provider under the local transmission planning process set forth in Appendix 1 to this Attachment K or involving Transmission Service under the Tariff, the senior representatives of the Transmission Provider and the customer shall attempt to resolve the dispute and may mutually agree to utilize a mediation service for that purpose. However, if such dispute is not resolved, then the Dispute Resolution Procedures set forth in Article 12 of the Tariff shall govern. If a dispute arises under this Attachment K involving the *FRCC Regional Transmission Planning Process* and/or cost allocation thereunder, then the Dispute Resolution Procedures set forth in Appendix 5 shall govern resolution of the dispute and the FRCC will notify the FPSC of any such dispute.

Section 7 Regional Participation

7.1 The *FRCC Regional Transmission Planning Process* begins with the consolidation of the long term transmission plans of all of the transmission providers/owners in the FRCC Region. Such transmission plans incorporate the integration of new firm resources as well as other firm commitments. Any generating or transmission entity not required to submit a 10 year plan to the FPSC submits its 10 year expansion plan to the FRCC, together with any issues or special needs they believe are not adequately addressed by the transmission providers/owners' 10 year plans. The FRCC process requires that the FRCC PC address any issue or area of concern not previously or adequately addressed with emphasis on constructing a more robust regional transmission system.

7.2 Each transmission provider/owner furnishes the FRCC with a study schedule for each system impact study so that other potentially affected transmission providers/owners can independently assess whether they may be affected by the request, and elect to participate in or monitor the study process. If a transmission provider/owner believes that it may be affected, it may participate in the study process.

7.3 FRCC has a reliability coordination arrangement with Southern Company Services, Inc. ("Southern"), which is located in the Southeastern Subregion of SERC Reliability Corporation ("SERC"). The purpose of the reliability coordination arrangement is to safeguard and augment the reliability on an inter-regional basis for Southern and the FRCC bulk power supply systems. This arrangement provides for exchanges of information and system data between Southern and the FRCC for the coordination of planning and operations in the interest of reliability. The arrangement also provides the mechanism for inter-regional joint studies and recommendations designed to improve the reliability of the interconnected bulk power system. The arrangement contributes to the safeguarding and augmenting of reliability through: (1) coordination of generation and transmission system planning, construction, operating, and protection to maintain maximum reliability; (2) coordination of interconnection lines and facilities for full implementation of mutual assistance in emergencies; (3) initiation of joint studies and investigations pertaining to the reliability of bulk power supply facilities; (4) coordination of maintenance schedules of generating units and transmission lines; (5) determination of requirements for necessary communication between the parties; (6) coordination of load relief measures and restoration procedures; (7) coordination of spinning reserve requirements; (8) coordination of voltage levels and reactive power supply; (9) other matters relating to the reliability of bulk power supply required to meet customer service requirements; and (10) exchange of necessary information, such as magnitude and characteristics of actual and forecasted loads, capability of generating facilities, programs of capacity additions, capability of bulk power interchange facilities, plant and system emergencies, unit outages, and line outages.

7.4 Southern Companies, Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "LG&E/KU"), Ohio Valley Electric Corporation ("OVEC"), Associated Electric Cooperative Inc., PowerSouth Energy Cooperative, Dalton Utilities, Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, South Mississippi Electric Power Association, Duke Energy Carolinas, and Duke Energy Progress sponsor the Southeastern Regional Transmission Planning ("SERTP") forum. The FRCC and the SERTP have established their respective links to transmission providers and FRCC/SERTP websites as applicable that contain study methodologies, joint transmission studies, and inter-regional transmission service and generator interconnection service related studies. The FRCC website link that contains this type of information can be found under the *Florida-SERC Inter-Regional Transmission Information* folder. In this folder please refer to a document entitled *FRCC Inter-regional Coordination Process* that describes how information, modeling data and expansion plans are shared. The SERTP website link is http://www.southeasternrtp.com. FRCC and SERTP transmission providers plan to attend transmission planning forums when study findings are presented to stakeholders that impact their respective transmission systems.

7.5 The FRCC is a member of the Eastern Interconnection Reliability Assessment Group ("ERAG") which includes other Eastern Interconnection reliability regional entities, the Midwest Reliability Organization, the Northeast Power Coordinating Council, Inc., Reliability First Corporation, SERC Reliability Corporation, and Southwest Power Pool. The purpose of ERAG is to ensure reliability of the interconnected system and the adequacy of infrastructure in their respective regions for the benefit of all end-users of electricity and all entities engaged in providing electric services in the region.

Section 8 Economic Planning Studies

8.1 In the performance of an economic sensitivity study that is identified as part of the *FRCC Regional Transmission Planning Process*, Transmission Provider plans to participate in such study utilizing the procedures that are contained in the *FRCC Regional Transmission Planning Process*. If Transmission Provider receives a specific request to perform economic studies for a transmission customer, Transmission Provider plans to utilize the OASIS for such requests. To the extent an economic study would involve other transmission providers/owners, Transmission Provider will coordinate with these providers/owners in performing the study. Stakeholders will collectively be allowed to request the performance of up to five (5) economic planning studies annually, at no charge to the individual requesting customer(s). The cost of the sixth and subsequent economic planning studies requested in a calendar year shall be assessed to the individual customer(s) requesting such studies. If there are similar interests for certain economic studies, stakeholders can coordinate with each other and the Transmission Provider during the transmission planning process to collectively select the five no-charge economic studies. If more than five economic planning studies are requested and the stakeholders are unable to agree on the selection of the five no-charge economic planning studies, then the Transmission Provider will select the five no-charge economic planning studies by selecting one study per stakeholder based on the time the economic planning study was submitted on OASIS (up to a maximum of five stakeholders) and continuing this iterative process until the five no-cost economic planning studies have been selected. In the event the Transmission Provider receives more than one request for an economic planning study which the Transmission Provider determines: (i) will have overlapping time periods of study; (ii) may involve the same facilities; and (iii) can be reasonably performed on a clustered basis, then the Transmission Provider will, either at the request of transmission customer(s) requesting the studies or if the Transmission Provider deems it to be appropriate, offer to cluster two or more qualifying study requests which meet the aforementioned criteria for an economic planning study. Transmission customers agreeing to the clustering must also agree: (i) to remain in the cluster throughout the performance of the study; and (ii) to share equally in the cost of the study, to the extent that there are such costs (i.e., for economic planning study requests beyond the first five in any calendar year). The Transmission Provider will consider an economic planning cluster study under this section as a single study in the context of the number of studies done at no cost each year.

8.2 The *FRCC Regional Transmission Planning Process* includes both economic and congestion studies. One of the sensitivities may include evaluating the FRCC Region with various generation dispatches that test or stress the transmission system, including economic dispatch from all generation (firm and non-firm) in the region. Other sensitivities may include specific areas where a combination/cluster of generation and load serving capability involving various transmission providers/owners in the FRCC experiences or may experience significant and recurring transmission congestion on their transmission facilities. Members of the FRCC PC may also request specific economic analyses that would examine potential generation resource options, demand resource options, or other types of regional economic studies, and to the extent information is available, may request a study of the cost of congestion. The FRCC PC may consider clustering studies as appropriate. Economic analyses should reflect the upgrades to integrate necessary new generation resources and/or loads on an aggregate or regional (cluster) basis.

Section 9 Cost Allocation

Subsections 9.1 – 9.3 apply to cost allocation for third party impacts resulting from the FRCC regional planning process; subsection 9.4 applies to cost allocation for CEERTS projects. The cost allocation provisions contained in the section relate to cost allocation procedures for specific circumstances as described herein. All other transmission cost allocation not specifically described below is provided in accordance with OATT provisions for generation interconnection and for network and point-to-point transmission service.

9.1 If a transmission expansion is identified as needed under the *FRCC Regional Transmission Planning Process* and such transmission expansion results in a material adverse system impact upon a third party transmission owner, the third party transmission owner may choose to utilize the FRCC Principles for Sharing of Certain Transmission Expansion Costs as outlined below in this Attachment K. The FPSC is involved in this process and provides oversight, guidance and may exercise its statutory authority as appropriate. A more detailed description of the FRCC Principles for Sharing of Certain Transmission Expansion Costs can be found on the FRCC website.

9.2 The FRCC Principles for Sharing of Certain Transmission Expansion Costs: (i) sets forth certain principles regarding the provision of financial funding to Transmission Owners (note: for this purpose, "Transmission Owner" means an electric utility owning transmission facilities in the FRCC Region) that undertake remedial upgrades to, or expansions of, their systems resulting from upgrades, expansions, or provisions of services on the systems of *other* Transmission Owners, and (ii) procedures for attempting to resolve disputes among Transmission Owners and other parties regarding the application of such principles. These principles shall not apply to transmission upgrades or expansions if, and to the extent that, the costs thereof are subject to recovery by a Transmission Owner pursuant to FERC Order No. 2003 or Order No. 2006.

9.3 Principles

9.3.1 Except for a CEERTS project for which it is not the project developer, each Transmission Owner in the FRCC Region shall be responsible for upgrading or expanding its transmission system in accordance with the *FRCC Regional Transmission Planning Process* consistent with applicable NERC and FRCC Reliability Standards and shall participate, directly or indirectly (as the member of a participating Transmission Owner, e.g., Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency), in the *FRCC Regional Transmission Planning Process* in planning all upgrades and expansions to its system.

9.3.2 If, and to the extent that, the need for a 230 kV or above upgrade to, or expansion of, the transmission system of one Transmission Owner (the "Affected Transmission Owner") is reasonably expected to result from, upgrade(s) or expansion(s) to, or new provisions of service on, the system(s) of another Transmission Owner or Transmission Owners (hereinafter "Precipitating Events"), and if such need is reasonably expected to arise within the FRCC planning horizon, the Affected Transmission Owner shall be entitled to receive Financial Assistance (as defined herein) from each other such Transmission Owner and other parties, to the extent consistent with the other provisions hereof. Such upgrade or expansion to the Affected Transmission Owner's system shall hereinafter be referred to as the "Remedial Upgrade." Upgrade(s), expansion(s), or provisions of service on another Transmission Owner's system that may result in the need for a Remedial Upgrade on the Affected Transmission Owner's system for which Financial Assistance is to be provided hereunder include the following Precipitating Events:

- A new generating unit(s) to serve incremental load

- A new or increased long-term sale(s)/purchase(s) to or by others (different uses)

- A new or modified long-term designation of Network Resource(s)

- A new or increased long-term, firm reservation for point-to-point transmission service

Specific non-Precipitating Events are as follows: 1) Transmission requests that have already been confirmed prior to adoption of these principles; 2) Qualifying rollover agreements that are subsequently rolled over; 3) Redirected transmission service for sources to the extent the redirected service does not meet the Threshold Criteria described in subsection 9.3.5.A. Existing flows would not be considered "incremental."; and 4) Repowered generation if the MW output of the facility is not increased, regardless of whether the repowered unit is used more/less hours of the year.

9.3.3 Except for a CEERTS project for which it is not the project developer and except to the extent that an Affected Transmission Owner is entitled to Financial Assistance from other parties as provided herein, each Transmission Owner shall be responsible for all costs of upgrades to, and expansions of, its transmission system; provided, however, that nothing herein is intended to affect the right of any Transmission Owner or another party from obtaining remuneration from other parties to the extent allowed by contract or otherwise pursuant to applicable law or regulation (including, for example, through rates to a Transmission Owner's customers).

9.3.4 Except for a CEERTS project for which it is not the project developer, each Transmission Owner shall be solely responsible for the execution, or acquisition, of all engineering, permitting, rights-of-way, materials, and equipment, and for the construction of facilities comprising upgrades or expansions, including Remedial Upgrades, of its transmission system; provided, however, that nothing herein is intended to preclude a Transmission Owner from seeking to require another party to undertake some or all of such responsibilities to the extent allowed by contract or otherwise pursuant to applicable law.

9.3.5 Threshold Criteria: The following criteria ("Threshold Criteria") must be satisfied in order for an Affected Transmission Owner to be entitled to receive Financial Assistance from another party or parties in connection with a Remedial Upgrade:

A. A change in power flow of at least a 5% or 25 MW, whichever is greater, on the Affected Transmission Owner's facilities which results in a NERC or FRCC Reliability Standards violation;

B. The Transmission Expansion must be 230 kV or higher voltage; and

C. The costs associated with the Transmission Expansion must exceed $3.5 million.

9.3.6 In order for a Transmission Owner to be entitled to receive Financial Assistance from another party or parties hereunder in connection with a particular Remedial Upgrade, that Transmission Owner must: (i) participate, directly or indirectly, in the *FRCC Regional Transmission Planning Process*, and (ii) identify itself as an Affected Transmission Owner and identify the subject Remedial Upgrade in a timely manner once it learns of the need for that Remedial Upgrade.

9.3.7 The following principles govern the nature and amount of Financial Assistance that an Affected Transmission Owner is entitled to receive from one or more other parties with respect to a Remedial Upgrade:

A. A recognition of the reasonably determined benefits that result from the Remedial Upgrades due to the elimination or deferral of otherwise planned transmission upgrades or expansions.

B. Remedial Upgrade costs, net of recognized benefits, shall be allocated fifty-fifty, respectively, based on:

- The sources or cluster of sources which are causing the need for the transmission expansion; and

- The load in the area or zone associated with the need for the Transmission Expansion. (For these purposes, network customer loads embedded within a transmission provider's service area in the Transmission Zone would not be separately allocated any costs as such loads would be paying their load ratio share of the affected transmission provider's costs.)

C. Initially, there are six zones in the FRCC region. A request by a party to modify one or more zones should be substantiated on its merits (e.g., technical analysis, area of limited transmission capability). Below are principles that will guide how the boundaries of zones are determined:

- Electrically, a substantial amount of the generation within a zone is used to serve load also within that zone.

- Transmission facilities in a zone are substantially electrically independent of other zones.

- Zones represent electrical demarcation areas in the FRCC transmission grid that can be supported from a technical perspective.

D. The Financial Assistance provided to an Affected Transmission Owner related to one or more transmission service requests keyed to new sources of power is subject to repayment without interest over a ten year period through credits for transmission service charges by the funding party and at the end of ten years through payment of any outstanding balance.

9.3.8 Implementation and Dispute Resolution Process:

A. As soon as practical after a Transmission Owner shall have identified itself as an Affected Transmission Owner because of the need for a Remedial Upgrade, that Transmission Owner and parties whose actions shall have contributed, or are reasonably expected to contribute, to the need for that Remedial Upgrade which may be responsible for providing Financial Assistance in connection therewith in accordance herewith shall enter into good faith negotiations to: (i) confirm the need and cause for the Remedial Upgrade and their respective responsibilities for providing Financial Assistance to the Affected Transmission Owner, and (ii) establish a fair and reasonable schedule and means by which such Financial Assistance is to be provided to the Affected Transmission Owner.

B. In the event the parties identified in the foregoing subsection are unable to reach agreement on the determination or assignment of cost responsibility within a sixty (60) day period, the dispute shall be resolved pursuant to the Dispute Resolution Procedures in Appendix 5.

C. Nothing in this document is intended to abrogate or mitigate any rights a party may have before any regulatory or other body having jurisdiction.

D. During those circumstances in which this section 9.3.8 pertaining to Dispute Resolution Process is being utilized due to parties being unable to reach agreement on the determination or assignment of cost responsibility associated with a Remedial Upgrade(s), the parties shall continue in parallel with the Dispute Resolution Process with the engineering, permitting and siting associated with the Remedial Upgrade(s). *The fact that a matter is subject to Dispute Resolution hereunder shall not be a basis for any party being relieved of its obligations under this document.*

9.4 Cost Allocation for CEERTS Projects

9.4.1 There are three potential sets of CEERTS project costs that will be allocated: developer costs, related local project costs, and displacement costs. The general principle is to allocate all of the prudently-incurred costs of a CEERTS project to the entities that benefit from the project in proportion to the benefits received, although a CEERTS project developer may accept a cost cap for the developer costs, in which case the developer's costs up to the cost cap will be allocated. Cost allocations are determined in terms of percentages, with each beneficiary allocated a percentage of the CEERTS project costs. Entities that receive no benefit from a CEERTS project will not be allocated any project costs.

9.4.2 Project beneficiaries for a CEERTS project will be transmission providers within the FRCC region enrolled in the regional planning process (on behalf of their retail and wholesale customers) which will benefit from the project.

9.4.3 The cost allocation for CEERTS reliability/economic projects is based on the following formula using terms defined in section 1.2.9.C: ((TP Estimated Avoided Project Cost Benefit + TP Estimated Alternative Project Cost Benefit + TP Estimated Transmission Line Loss Value Benefit) / (Total Estimated Avoided Project Cost Benefit + Total Estimated Alternative Project Cost Benefit + Total Estimated Transmission Line Loss Value Benefit)) * Estimated CEERTS Project Cost. The cost allocation dollar amounts calculated here using estimated cost information will further be translated to a percentage for each beneficiary as a ratio of their allocated share of the total estimated cost of the CEERTS project. These percentages will be used to allocate actual CEERTS project costs that are recoverable pursuant to the applicable subsection of section 9.4.5. Examples of CEERTS project cost allocation are provided in Appendix 4, Examples 1 and 2.

9.4.4 The costs for CEERTS public policy projects that are identified through the process described in section 11~~,~~ will be allocated to the enrolled transmission providers whose transmission systems provide access to the public policy resources. The cost allocation for each enrolled transmission provider will be as follows:

- Individual enrolled transmission provider MWs = number of megawatts of public policy resources enabled by the public policy project for the customers (including Native Load) within their transmission service territory~~ with confirmed public policy resource needs (see section 1.2.9.B for a description of how this verification will occur)~~.

- Total MWs = total number of megawatts of public policy resources enabled by the public policy project.

- Individual enrolled transmission provider cost allocation percentage = (Individual enrolled transmission provider MWs/Total MWs).

An example of the CEERTS public policy cost allocation is provided in Appendix 4, Example 3. These percentages will be used to allocate actual CEERTS project costs that are recoverable pursuant to the applicable subsection of section 9.4.5.

The process to interconnect individual generation resources is provided for under the generator interconnection section of each utility's OATT and not under this process.

Requests for transmission service that originate in a utility's system and terminate at the border shall be handled through that utility's OATT.

9.4.5 Transmission Project Funding and Rate Base/Cost Recovery:

A. If incumbent enrolled transmission providers are the only transmission developers for a particular project, then they shall have two options in the initial transmission project funding and subsequent cost recovery of developer costs. Note that if an incumbent enrolled transmission provider develops a CEERTS project and is not FERC-jurisdictional, it will make any requisite FERC filings through the declaratory order process used for non-jurisdictional enrolled transmission providers rather than under FPA section 205:

(1) Incumbent enrolled transmission providers may fund the transmission project in proportion to their cost responsibility for the project. For the portions of the projects that each of the companies were building that are related to their cost responsibility, the companies would include those transmission costs as identified in a Contribution in Aid to Construction (CIAC) filing at FERC within their respective rate bases and transmission revenue requirements. The costs would be reflected in FERC filed OATT rates in Account 107, Construction Work in Progress. When the assets go into service, the balance will be moved to Account 101, Electric Plant in Service and the Units of Property will be unitized to the FERC Accounts corresponding to the Units of Property. This treatment is for accounting purposes: a FERC filing and FERC approval would still be required to include Construction Work in Progress in rates. For the portion of the funding that was being provided for the transmission to be built by someone other than the incumbent, the payments by the incumbent (for their cost responsibility) would be recorded in Account 303, Miscellaneous Intangible Plant and amortized by debiting Account 404, Amortization of Limited-Term Electric Plant, and crediting Account 111, Accumulated Provision for Amortization of Electric Utility Plant. The amortization of the investment would be derived using a composite factor based on the most recently approved depreciation rates for the constructing company. The calculation of the composite factor would be based on the Units of Property installed in the transmission project. The amortization will begin when the project is declared in service. The costs and amortization would be reflected in FERC filed OATT rates until the investment is fully amortized to expense. The company receiving the money would treat these monies as a CIAC and thus have no associated net book investment in its transmission rate base. CIAC agreements will be filed with FERC prior to any CIAC payments being made to the constructing developer. Enrolled t~~T~~ransmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC for authorization to include the intangible asset investment and amortization expense in the formula rate. Traditional cost-based ratemaking procedures would be used to determine the impact of including the intangible asset investment in rate base and the amortization expense in operating expenses in deriving OATT rates. CIAC agreements filed with FERC would include workpapers to support the costs included in the

determination of revenue requirements. See Example 1 provided in Appendix 6 for more detail and accounting treatment.

(2) Incumbent enrolled transmission providers may fund the portion of the transmission project that their company would be building/developing. Incumbent enrolled transmission providers would include the total transmission project costs that they are funding within their respective rate bases and transmission revenue requirements for recovery in their routine rate processes. For those portions of the project costs that are over and above their cost responsibility, the incumbent enrolled transmission providers would file with FERC for authorization to recover their Transmission Revenue Requirement ("TRR") associated with those project costs to be directly assigned to the beneficiary(ies) responsible for that portion of the cost assignment. The TRR when received by the incumbent developer would be treated as a revenue credit recorded in Account 456, Miscellaneous Revenue in its cost of service to offset the inclusion of other beneficiary(ies) assigned cost in rate base and revenue requirement. In addition to including the TRR for those portions of the project costs that were over and above their cost responsibility, the incumbent enrolled transmission providers would also include any TRR costs allocated to them in their FERC-filed cost of service in support of FERC-approved OATT rates. Enrolled t~~T~~ransmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC for authorization to include their allocated TRR costs in the formula rate. See Example 2 provided in Appendix 6 for more detail and accounting treatment.

B. If a non-incumbent developer builds the CEERTS project, it shall file with FERC for authorization to recover its developer costs in the form of a TRR from the incumbent enrolled transmission providers in accordance with their cost responsibilities as determined by the cost allocation methodologies. The incumbent enrolled transmission providers may include those costs allocated to them in their respective wholesale rates (*e.g.*, in FERC-filed cost of service in support of FERC approved OATT rates). Enrolled t~~T~~ransmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC to include their allocated TRR costs in the formula rate. See Example 3 provided in Appendix 6 for more detail and accounting treatment.

C. Incumbent enrolled transmission providers with formula-based OATT rates shall be allowed to revise their formula rates to include the intangible asset investment balance as directly assignable transmission function rate base, and amortization expense should be included as transmission function specific expense. Formula-based OATT rates shall be revised by submitting a separate FPA section 205 filing with FERC.

D. Enrolled transmission provider(s) will be responsible for recovering their related local project costs from the beneficiaries allocated such costs through a FPA section 205 filing if the enrolled transmission provider is FERC-jurisdictional or through FERC's declaratory order process if the enrolled transmission provider is non-jurisdictional.

E. Enrolled transmission provider(s) will be responsible for recovering their actual displacement costs, if applicable, through a FPA section 205 filing if the enrolled transmission provider is FERC-jurisdictional or through FERC's declaratory order process for non-jurisdictional enrolled transmission owners. In such filing, the enrolled transmission provider(s) will allocate displacement costs in the same manner as the CEERTS project costs are allocated.

~~F. If a CEERTS project is selected in the regional transmission plan for purposes of cost allocation that could potentially result in reliability impacts to a transmission system in an adjacent transmission planning region and the relevant transmission provider in such adjacent region does not want these section 9.4 cost allocation for CEERTS projects methodologies to be applied or such methodologies are not eligible to be applied, the FRCC will coordinate with the neighboring planning region and transmission provider on any further evaluation. The costs associated with any required upgrades identified in such adjacent planning region will not be included in the CEERTS project costs that are allocated under this tariff.~~

9.4.6 Neighboring Transmission Planning Region Potential Cost Impacts Not Included in FRCC's CEERTS Cost:

The costs associated with any required upgrades identified through the FRCC's CEERTS project evaluation process identified in section 1.2.9.F for the neighboring transmission planning region will not be included in the CEERTS cost within the FRCC. However, nothing in this Attachment K prevents the beneficiaries or project sponsor of a CEERTS project that causes the need for upgrades in another region from voluntarily negotiating a resolution of the project impacts with the transmission owner(s) in the other region.

~~9.4.6~~9.4.7 Allocation of Transmission Rights:

Enrolled t~~T~~ransmission providers allocated costs of CEERTS projects shall have priority with regard to any transmission rights associated with such projects, in proportion to their respective share of such costs. Any use of the transmission rights allocated to the Transmission Provider, including use by the Transmission Provider itself, shall be governed by this Tariff.

Section 10 Recovery of Planning Costs

10.1 Planning study costs incurred by the Transmission Provider in the performance of studies requested by a customer/stakeholder associated with transmission service or generator interconnection service are separately addressed in this tariff under provisions that require the customer/stakeholder to pay the cost of such studies. Planning study costs incurred by the Transmission Provider in the performance of the first five economic planning studies will be absorbed by the Transmission Provider in its normal course of business of performing its obligations under this Attachment K. The cost of the sixth and additional economic planning studies in a calendar year will be assessed to the requesting entity as set forth in section 8.1. Other general transmission planning costs not associated with the above studies are routine cost-of-service items that would be reflected in both wholesale and retail transmission rates as appropriate.

Section 11 Public Policy Planning

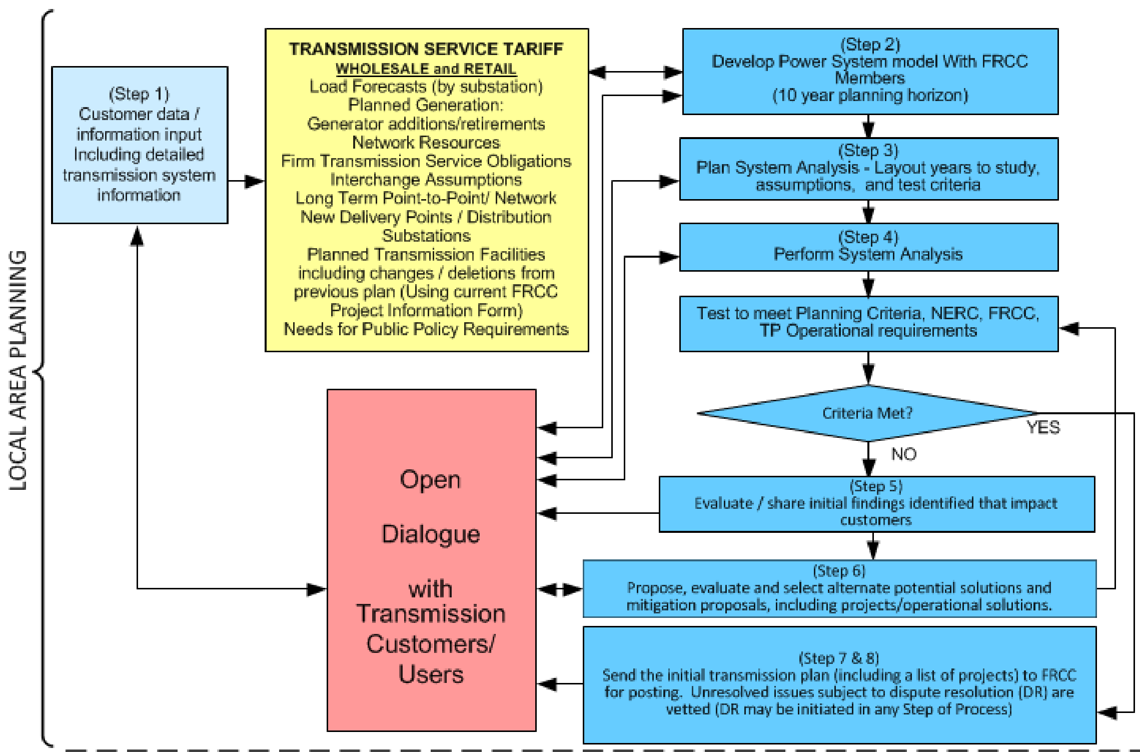
11.1 To be considered in transmission planning, a public policy requirement must be reflected in state, federal, or local law or regulation (including an order of a state, federal, or local agency). If a stakeholder identifies a transmission need that is driven by a public policy requirement, it must submit a written description of the need to the FRCC PC, prior to January 1st of the first year of the biennial regional projects planning cycle, for consideration in regional planning during that planning cycle. To the extent the information is available to the stakeholder, the description of the need ~~must~~should: 1) identify the state, federal, or local law or regulation that contains the public policy requirement; 2) identify the type of entity(ies) in the region to which the public policy requirement applies; 3) identify the subset of entities in the region subject to the public policy requirement that have a transmission need driven by the public policy requirement; 4) describe the type and nature of the transmission service, including the number of megawatts, needed from the enrolled transmission providers by such subset of entities to meet that transmission need. Any stakeholder submitting a potential public policy transmission need to the FRCC PC may, but is not required to, also propose a transmission project(s) to meet such a need along with its description of the need. All submissions will be posted on the FRCC website for public comment and will be reviewed to determine if a public policy requirement is driving a transmission need for which a solution is required. The FRCC PC, under the oversight of the FRCC Board, may seek, on a voluntary basis, additional information from entities identified as having potential needs and then will evaluate the submittals and any additional information to make a decision as to whether a public policy requirement is driving a transmission need for which a solution is required and will post this determination on the FRCC website prior to March 1st of the first year of the biennial regional projects planning cycle, along with an explanation and record of that determination (including a negative determination). If a public policy transmission need is identified for which a solution is required, CEERTS and local projects shall be proposed to address such a need.

Appendix 1 to Attachment K

Local Transmission Network Planning Process – Process Description

The Local Transmission Network Planning Process ("Local Process") is performed annually with the Transmission Provider's plan being finalized on or about April 1st of each calendar year. The times shown (in months) for each of the steps contained in the Local Process are target dates that recognize some potential overlapping of the various activities. The Transmission Provider may develop a different timeline where warranted with the concurrence of the Transmission Provider's Customers/Stakeholders. The timelines and dates in this Appendix 1 to Attachment K are to be used as guidelines subject to modification (modified or expedited) as warranted. It is also recognized and understood that under the Transmission Provider's OATT, there are certain FERC mandated timelines that are applied to Transmission Service Requests ("TSRs") and Generator Interconnection Service Requests ("GISRs") that may conflict and be of higher priority than the Local Process. Therefore, Transmission Provider's receipt of TSRs and/or GISRs may require the modification, from time to time, of the timelines described below.

TRANSMISSION PROVIDER's (TP) LOCAL TRANSMISSION NETWORK PLANNING PROCESS



Proceed to FRCC Regional Planning **Process)**

(Proceed to FRCC Regional Planning Process)

Local Transmission Network Planning Process – Process Description Overview:

- The Transmission Provider, which is ultimately responsible for the development of the Transmission Provider's annual 10 Year Expansion Plan, will lead the Local Process on a coordinated basis with the Customers/Stakeholders. This Local Transmission Planning Process will be implemented in such a manner as to ensure the development of the Local Transmission Plan in a timely manner. The Transmission Provider will facilitate each meeting throughout the process. The Transmission Provider will encourage an open dialogue and the sharing of information with Customers/Stakeholders (subject to confidentiality requirements and FERC Standards of Conduct – *note:* the provision for handling of information also applies to all steps of the Local Process) in the development of the Local Transmission Plan.

- Customers/Stakeholders are invited to participate in the Transmission Provider's Local Process.

- The Local Process will comply with the FERC nine principles as well as the provisions below.

- All annual initial kick-off meetings will be open to all Customers/Stakeholders and noticed by the Transmission Provider to all Customers/Stakeholders with sufficient time to arrange for travel planning and attendance (two week minimum). The annual initial kick-off meeting will be a face-to-face meeting; otherwise, with the consent of the Customers/Stakeholders, meetings may be organized as face-to-face meetings, conference calls, web-ex events, etc., wherein the dialogue and communications will be open, direct, detailed, and consistent with the FERC Standards of Conduct and confidentiality requirements.

- The Customers/Stakeholders may initiate the dispute resolution process at any point in the Local Process where agreement between the Transmission Provider and Customer(s)/Stakeholder(s) cannot be reached.

- The entities generally responsible for undertaking the tasks described below are designated as the TP (Transmission Provider) and/or the S (Customers/Stakeholders).

The study process will include the following steps:

A. Data Submission Requirements (STEP 1 – 3 months)

In order for The Transmission Provider to carry out its responsibility of developing the Transmission Provider's annual 10 Year Expansion Plan and leading the Local Process on a coordinated basis with the Customers/Stakeholders, data submission by the Customer/Stakeholder on a timely manner (on or before January 1st of each year) is essential. As such, the following data submission requirements from Customers/Stakeholders to the Transmission Provider are established. The Customers/Stakeholders will submit data to the Transmission Provider in a format that is compatible with the transmission planning tools in common use by the Transmission Provider. The Transmission Provider will identify the data format to be used by the Customers/Stakeholders for all data submissions, or absent a Transmission Provider identified data format, the Customers/Stakeholders will use their discretion in selection of data format. Examples of data that may be required are:

- Load forecasts, if appropriate:

    - Coincident and non-coincident Peak load forecasts will be provided for the subsequent 11 years, for each summer and winter peak season, with real power and reactive power values for each load serving substation (reflected to the transformer high-side) or delivery Point, as applicable.

- Transmission Delivery Points, if appropriate:

    - Delivery Point additions and/or Delivery Point modifications that have not previously been noticed to the Transmission Provider will be communicated by the Customer/Stakeholder to the Transmission Provider via the standard Delivery Point Request letter process.

    - Delivery Point additions and/or Delivery Point modifications that have not previously been included in the FRCC Databank Transmission Planning models will be provided by the Customers/Stakeholders to the Transmission Provider via the standard FRCC Project Information Sheet ("PIF") per the attached Transmission Provider provided form and by the Siemens PTI PSS/E IDEV file format, compatible with the Siemens PTI PSS/E version in common use throughout the FRCC Region at that time.

- Network Resource Forecast, if appropriate:

    - Network Resource forecasts will be provided for the subsequent 11 years, for each summer and winter peak season. At a minimum, the following data will be provided: 1. the name of each network resource; 2. the total capacity of each network resource; 3. the net capacity of each resource; 4. the designated network capacity of each resource; 5. the Balancing Authority Area wherein each network resource is interconnected to the transmission grid; 6. the transmission path utilized to deliver the capacity and energy of each network resource to the Transmission Provider's transmission system; 7. the Transmission Provider's point of receipt of each network resource; 8. the contract term of each network resource, if not an owned network resource; and 9. the dispatch order of the entire portfolio of network resources (subject to confidentiality requirements and Standards of Conduct).

- Needs driven by public policy requirements, if appropriate:

    - To be considered in the local transmission network planning process, a public policy requirement must be reflected in state, federal, or local law or regulation (including an order of a state, federal, or local agency). If a stakeholder identifies a transmission need that is driven by a public policy requirement, it must submit a written description of the need to the Transmission Provider, for consideration in local planning during that planning cycle. To the extent the information is available to the stakeholder, the description of the need ~~must~~should:

1) Identify the state, federal, or local law or regulation that contains the public policy requirement;

2) Identify the type of entity(ies) in the Transmission Provider's area to which the public policy requirement applies;

3) Identify the subset of entities in the area subject to the public policy requirement that have a transmission need driven by the public policy requirement;

4) Describe the type and nature of the transmission service needed from the transmission provider by such subset of entities to meet that transmission need.

- How, where, and to whom, the data will be submitted to:

  - If hardcopy, the Transmission Provider will provide the mailing address;
  - If faxed, the Transmission Provider will provide the fax number;
  - If e-mailed, the Transmission Provider will provide the e-mail address;
  - If delivered to a password protected FTP site or e-vault, the Transmission Provider will provide the folder for the data, the contact person to be notified of the data delivery, etc. consistent with confidentially requirements and FERC Standards of Conduct.

The Transmission Provider will provide the name and contact details for the Transmission Provider point of contact for data submittal questions.

B. Stakeholder Data Submissions (S) (STEP 1 – con't)

- On or before January 1st of each calendar year, the Customers/Stakeholders will submit the required data (as directed by the Transmission Provider procedures communicated in A. above), plus any additional data that they believe is relevant to the process.

- On or before January 1st of each calendar year, the Customers/Stakeholders will submit to the Transmission Provider the name(s) and contact details for those individuals that will represent them as the point(s) of contact for resolution of any data submittal or study questions/conflicts.

- On or before January 1st of each calendar year, the Customers/Stakeholders will submit the name(s) of those individuals that will represent them during the FRCC Data Bank Transmission Planning Model development process and throughout the Local Process. Name(s), contact details, and their FERC Standards of Conduct status (i.e., Reliability Only, Merchant function, etc.) will be provided. The contact individuals can be changed by the Customers/Stakeholders with notice to Transmission Provider.

- On or before January 1st of each calendar year, the Customers/Stakeholders will submit a written description of a transmission need that a Stakeholder believes is driven by a public policy requirement to the Transmission Provider. Any stakeholder submitting a potential public policy transmission need to the Transmission Provider may, but is not required to, also propose a transmission project(s) to meet such a need along with its description of the need.

  - All submissions will be posted on the Transmission Provider's website for public comment and will be reviewed to determine if a public policy requirement is driving a transmission need for which a solution is required.

  - The Transmission Provider may seek, on a voluntary basis, additional information from entities identified as having potential needs and then will evaluate the submittals and any additional information to make a decision as to whether a public policy requirement is driving a transmission need for which a solution is required and will post this determination on the Transmission Provider's website prior to April 1st of the local transmission network planning cycle, along with an explanation and record of that determination (including a negative determination). If a public policy transmission need is identified for which a solution is required local projects shall be proposed to address such a need.

C. FRCC Data Bank Transmission Planning Model Development Process (TP/S) (STEP 2 – 2 months)

- The FRCC Regional Data Bank Development Process will control the model development schedule and work product as established by the applicable FRCC Working Group.

D. Kick-off for Transmission Provider's Local Transmission Network Planning Process (STEP 2 – con't - 1 month)

- The Transmission Provider will, approximately two (2) weeks prior to the second quarter initial kick-off meeting (or other date, if Transmission Provider and Customers/Stakeholders agree), communicate via e-mail with all Customers/Stakeholders the schedule/coordination details of the Transmission

Provider's Local Process kick-off meeting(s). Customer/Stakeholder shall provide to Transmission Provider a confirmation of their intent to participate in the initial kick-off meeting at least three (3) days prior to such meeting. (TP)

- The Transmission Provider will, in advance of the Kick-off meeting(s), with sufficient time for Customer/Stakeholder review, provide to the Customers/Stakeholders a proposed study schedule, the NERC and FRCC Reliability Standards that will apply to the study, and/or guidelines that will apply to the study and Transmission Provider developed criteria that will apply to the study, including public policy requirements. (TP)

- The initial Kick-off meeting in the second quarter of the calendar year will begin the Transmission Provider's Local Process. The Transmission Provider will review and validate the input data assumptions received from each Customer/Stakeholder, discuss the proposed study schedule, and discuss the study requirements, which will include, but not be limited to, the following:

  - The methodologies that will be used to carry out the study (TP/S)

  - The specific software programs that will be utilized to perform the analysis (TP)

  - The Years to study (TP/S)

  - The load levels to be studied (e.g., peak, shoulder and light loads) (TP/S)

  - The criteria for determining transmission contingencies for the analysis (i.e. methods, areas, zones, voltages, generators, etc.) (TP/S)

  - The Individual company criteria (i.e., thermal, voltage, stability and short circuit) by which the study results will be measured (TP/S)

  - The NERC reliability standards by which the study results will be measured (TP/S)

  - The FRCC reliability standards and requirements by which the study results will be measured (TP/S)

  - Customer/Stakeholder proposed study scenarios for Transmission Provider consideration in the analysis (TP/S)

  - Potential solutions proposed by Stakeholders to identified transmission needs driven by public policy requirements (TP/S)

- The kick-off process will be complete when the schedule, standards, criteria, rules, tools, methods and Customer/Stakeholder participation are finalized for the study process to (described below) begin. (TP/S)

E. Case Development (TP) (STEP 3 – 1 month)

- Utilizing all of the data received from the Customers/Stakeholders during the data submission stage and the standards, criteria, rules, tools, and methods determined in the kick-off meeting(s), the Transmission Provider will develop the base case models to be used for the study. These models will be developed in the Siemens PTI PSS/E file format, compatible with the Siemens PTI PSS/E version in use by the Transmission Provider.

- Utilizing all of the data received from the Customers/Stakeholders during the data submission stage and the standards, criteria, rules, tools, and methods determine in the kick-off meeting, the Transmission Provider will develop the change case models to be used for the study. These models will be developed in the Siemens PTI PSS/E file format, compatible with the Siemens PTI PSS/E version in use by the Transmission Provider.

- The Transmission Provider will electronically post and provide notice to the Customers/Stakeholders of the posting of the base case models, the change case models and/or the IDEV files.

F. Perform System Analysis (STEP 4 - 1 to 2 months)

- The Transmission Provider will perform the study analyses (verification that thermal, voltage, stability and short circuit values meet all planning criteria) on the local transmission plan (including potential solutions to identified transmission needs driven by public policy requirements) and produce the initial unfiltered, un-processed input data, output data, and files. (TP).

- The Transmission Provider will electronically post and provide notice to the Customers/Stakeholders of the posting of the initial unfiltered, un-processed input data, output data, and files. (TP/S)

G. Assessment and Problem Identification (STEP 5 - 1 month)

- The Transmission Provider will evaluate at the local level the initial unfiltered, un-processed output data to identify any problems / issues for further investigation. The Transmission Provider will document, electronically post, and provide notice to the Customers/Stakeholders if there is an impact to them of the posting of the evaluation results documentation associated with the impact to the Customer/Stakeholder. (TP/S)

- The Customers/Stakeholders may perform their own additional sensitivities. (S)

H. Mitigation / Alternative Development (STEP 6 - 1 to 2 months)

- The Transmission Provider will identify potential solutions / mitigation proposals, including solutions to identified transmission needs driven by public policy requirements, to address problems / issues. (TP)

- The Transmission Provider will document, electronically post, and provide notice to the Customers/Stakeholders of the posting of the identified potential solutions / mitigation proposals to address problems / issues related to the impacted Customer(s)/Stakeholder(s).

- The Customers/Stakeholders may provide alternative potential solutions / mitigation proposals, including alternative solutions to identified transmission needs driven by public policy requirements, for the Transmission Provider to consider. Such information shall be provided in IDEV format and posted. (TP/S)

- The Transmission Provider will determine the effectiveness of the potential solutions through additional studies (thermal, voltage, stability and short circuit). The Transmission Provider may modify the potential solutions, as necessary, such that required study criteria are met. (TP)

- The Transmission Provider will identify feasibility, timing and cost-effectiveness of proposed solutions that meet the study criteria. (TP/S)

I. Selection of Preferred Transmission Plan (STEP 6 con't - 1 to 2 months)

- The Transmission Provider, in consultation with the Customers/Stakeholders, will compare the alternatives and select the preferred solution / mitigation alternatives based on feasibility, timing and cost effectiveness that provide a reliable and cost-effective transmission solution, taking into account neighboring transmission providers' transmission plans. (TP/S)

- In case of Transmission Provider and Customer/Stakeholder dispute, the dispute resolution process described in section 6.1 will be utilized. (TP/S)

J. Send Selected Local Transmission Network Plan Results (Transmission Provider's Ten Year Expansion Plan) to the FRCC (STEPS 7 & 8 - 1 to 2 months)

- The Transmission Provider will submit the Transmission Provider's proposed local transmission network plan results (the Transmission Provider's 10 Year Expansion Plan) to the FRCC for posting with other transmission plans as the FRCC's initial regional transmission expansion plan (reference the *Initial Plans* on the FRCC website), along with an indication whether there are any pending disagreements regarding the Plan (and if there are, will elicit from the dissenting entity(ies), and provide, a minority report regarding such differences of opinion). The Transmission Provider's 10 Year Expansion Plan will include all transmission system projects without differentiation between bulk transmission system projects and lower voltage transmission system projects (i.e. all projects 69 kV and above). This Transmission Provider submittal to the FRCC will be made on or about April 1 and will become part of the initial FRCC regional transmission plan. (TP)

- The *FRCC Regional Planning Process* will now start and the FRCC Regional Planning Process rules and guidelines will now control the transmission planning process. (TP/S)

- Following completion of the Transmission Provider's submission of the local transmission network plan results (the Transmission Provider's 10 Year Expansion Plan) to the FRCC, the Transmission Provider will, either directly or through the FRCC project status reporting process, make available to the Customers/Stakeholders project descriptions, project scheduled in-service dates, project status, etc. for all projects. This information should be updated no less often than quarterly. (TP)

Appendix 2 to Attachment K

FRCC Quorum and Voting Sectors

Note: The below descriptions of the FRCC's Quorum and Voting provisions were extracted from the FRCC *Rules of Procedure for FRCC Standing Committees.* The FRCC PC~~lanning~~ ~~Committee~~ is one of the Standing Committees within the FRCC.

A. Quorum

Representation at any meeting of the standing committees of 60% or more of the total voting strength of the Standing Committee, shall constitute a quorum for the transaction of business at such meeting; provided, however, that action on matters dealing with the scope or funding of Member Services shall require sixty percent (60%) or more of the total voting strength of members of the Standing Committee representing Voting Members that are Services Members; and provided further that a quorum shall require that at least three (3) Sectors are represented, all three of which shall be Sectors, a majority of the members of which are Services Members in the case of a quorum for action on matters governing Member Services.

If a quorum is not present at any meeting of the standing committees, then no actions may be taken for the purpose of voting. The representatives present may decide to have discussions concerning agenda items as long as voting is not called.

B. Voting

Voting is by Sector. Each voting representative present at a meeting is assigned a vote equal to the voting strength of their Sector, as provided in this section, divided by the number of voting representatives present in that Sector, except that no voting representative present at a meeting shall have more than one (1) vote, except an Investor Owned Utility Sector voting representative who may have up to 1.167 votes. Action by the Standing Committee shall require an affirmative vote equal to or greater than sixty percent (60%) of the total voting strength of the Standing Committee.

Sector Votes

(1) Suppliers Sector	2.5 Votes
(2) Non-Investor Owned Utility Wholesale Sector	2 Votes
(3) Load Serving Entity Sector	
Municipal	0.5 Vote
Cooperative	0.5 Vote
(4) Generating Load Serving Entity Sector	3.0 Votes
(5) Investor Owned Utility Sector	3.5 Votes
(6) General	1 Vote
Total	13 Votes

Appendix 3 to Attachment K
Project Developer Qualification Criteria

1. Demonstration that the project developer is technically, and financially capable of (i) completing the CEERTS project in a timely and competent manner; and (ii) operating and maintaining the CEERTS facilities consistent with Good Utility Practice and applicable reliability criteria for the life of the project. To support this demonstration, the following information should be provided/shown:

   A. Project developer's current and expected capability to finance, or arrange financing for the transmission facilities:

      1. Evidence of its demonstrated experience financing or arranging financing for transmission facilities, including a description of such projects (not to exceed ten) over the previous ten years, the capital costs and financing structure of such projects, a description of any financing obtained for these projects through any approved rates ~~approved by the Commission or state regulatory agency~~, the financing closing date of such project, and whether any of the projects are in default;

      2. Its audited financial statements from the most recent three years and its most recent quarterly financial statement, or equivalent information;

      3. Current credit ratings from Moody's Investor Services and Standard & Poors, if available;

      4. A summary of any history of bankruptcy, dissolution, merger, or acquisition of the project developer or any predecessors in interest for the current calendar year and the five calendar years immediately preceding its submission of information related to affiliated entities;

      5. A summary of outstanding liens against the developer(s); and

      6. Such other evidence that demonstrates its current and expected capability to finance a CEERTS project.

      The project developer must identify the portions of this financial data that would need to be treated as confidential information in accordance with the FRCC confidentiality practices and subject to disclosure only to those that have signed a confidentiality agreement.

   B. Total dollar amount of CEERTS estimated project(s) cost up to which the project developer wants to be deemed qualified.

   C. A discussion of the project developer's business practices that demonstrate that its business practices are consistent with Good Utility Practices for proper licensing, designing, right-of-way acquisition, constructing, operating and maintaining transmission facilities that will become part of the regional transmission grid. The project developer shall also provide the following information for the current calendar year and the previous five calendar years:

1. A summary of any violations of law by the project developer found by federal or state courts, federal regulatory agencies, state public utility commissions, other regulatory agencies, or attorneys general; and

2. A summary of any instances in which the project developer is currently under investigation or is a defendant in a proceeding involving an attorney general or any state or federal regulatory agency, for violation of any laws, including regulatory requirements.

D. Technical and engineering qualifications and experience;

E. Past history of meeting transmission project schedules;

F. Past history regarding providing construction and maintenance of transmission facilities and/or contracting for the construction and maintenance of transmission facilities;

G. Capability to adhere to standardized construction, maintenance and operating practices;

H. Plans for compliance with all applicable reliability standards:

I. Planning standards that will be used to develop the project: and

J. Plans to obtain the appropriate NERC certifications.

2. An attestation from an officer of the project developer stating that the information that is being submitted is true and that the project developer will comply with the provisions identified in the qualification data submittal, and will submit a biennial (or more often if the information provided has materially changed) update of the information submitted, accompanied by an attestation from an officer of the project developer that the previously submitted information remains correct and has not materially changed since the last attestation, with such attestation to be submitted biennially while that transmission developer has a transmission project under consideration in the FRCC Regional Planning Process, under construction in the FRCC region or in-service within the FRCC region.

3. For joint ventures, partnerships, or other multiple-party developer arrangements, the qualification criteria above will be applied to the designated lead entity, which will be responsible for meeting the qualification criteria. Sharing of such responsibilities with other entities may be achieved contractually between the designated lead entity and its partners.

Appendix 4 to Attachment K
Examples of CEERTS Cost Allocation Methodology

Example 1: Reliability/Economic Project

- CEERTS project where Enrolled Transmission Providers A, B and C all receive benefits from the project.
- The project developer is a non-incumbent developer

Assumptions:

- Estimated CEERTS Project Cost = $401M:
  - Estimated Developer Cost = $400M
  - Total Estimated Related Local Project Costs = $1M
- Total Estimated Avoided Project Cost Benefit = $500M:
  - Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $300M
  - Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $200M
  - Enrolled Transmission Provider C Estimated Avoided Project Cost Benefit = $0
- Total Estimated Alternative Project Cost Benefit = $0M
- Total Estimated Transmission Line Loss Value Benefit = $14M:
  - Enrolled Transmission Provider A Estimated Transmission Line Loss Value Benefit = $4M
  - Enrolled Transmission Provider B Estimated Transmission Line Loss Value Benefit = $5M
  - Enrolled Transmission Provider C Estimated Transmission Line Loss Value Benefit = $5M

Benefit to Cost Ratio:

- ("Total Estimated Avoided Project Cost Benefit" ($500M) plus "Total Estimated Alternative Project Cost Benefit" ($0M) plus "Total Estimated Transmission Line Loss Value Benefit" ($14M)) divided by Estimated CEERTS Project Cost ($401M) = 1.28, therefore this CEERTS project passes the benefit to cost ratio threshold.

CEERTS Project Cost Allocation:

- (Percentages in example are rounded to nearest whole percentage)

- Enrolled Transmission Provider A = ($300M + $4) ÷ $514M = 59%
- Enrolled Transmission Provider B = ($200M + $5M) ÷ $514M) = 40%
- Enrolled Transmission Provider~~s~~ C = ($0 + $5M) ÷ $514M) = 1%

Example 2: Reliability/Economic Project

- CEERTS project where Enrolled Transmission Providers A & B each receive avoided cost benefits from the project
- There are no transmission loss benefits
- The project developer is a non-incumbent developer

Assumptions:

- Estimated CEERTS Project Cost = $400 M:
  - Estimated Developer Cost = $400 M
- Total Estimated Avoided Project Cost Benefit = $300 M:
  - Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $100 M
  - Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $200 M
- Total Estimated Alternative Project Cost Benefit = $0M

Benefit to Cost Ratio:

- "Total Estimated Avoided Project Cost Benefit" ($300 M) divided by Estimated CEERTS Project Cost ($400 M) = 0.75, therefore this CEERTS project does not pass the benefit to cost ratio threshold.

CEERTS Project Cost Allocation:

- N/A

Example 3: Public Policy Project

- CEERTS project where LSEs within Enrolled Transmission Providers A, B and C each receive benefits from the project
- The project developer is a non-incumbent developer

Assumptions:

- Public policy CEERTS project enables access to a total of 600 MW of public policy resources

- Public policy CEERTS project enables LSEs within Enrolled Transmission Providers A, B and C to access the public policy resources:

  - Enrolled Transmission Provider A = 100 MWs
  - Enrolled Transmission Provider B = 200 MWs
  - Enrolled Transmission Provider C = 300 MWs

CEERTS Project Cost Allocation:

  - Enrolled Transmission Provider A = (100 MW / 600 MW) = 17%
  - Enrolled Transmission Provider B = (200 MW / 600 MW) = 33%
  - Enrolled Transmission Provider C = (300 MW / 600 MW) = 50%

Example 4: Newly-Proposed CEERTS Project Displacing a Previously-Approved CEERTS Project

- Previously-approved CEERTS project was estimated to provide LSEs within Enrolled Transmission Provider A and B benefits

- Newly-proposed CEERTS project would displace the previously-approved CEERTS project as well as being estimated to provide LSEs within Enrolled Transmission C benefits from the newly-proposed CEERTS project

- The newly-proposed CEERTS project would displace the previously-approved CEERTS project

Previously-Approved CEERTS Project:

Assumptions:

- Estimated Previously-Approved CEERTS Project Cost = $75M

- Total Estimated Previously-Approved CEERTS Project Avoided Project Cost Benefit = $100M

  - Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $50M
  - Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $50M

Previously-Approved CEERTS Project Cost Allocation:

- (Percentages in example are rounded to nearest whole percentage)

- Enrolled Transmission Provider A = ($50M / $100M) = 50%
- Enrolled Transmission Provider B = ($50M / $100M) = 50%

Previously-Approved CEERTS Project Displaced by a Newly-Proposed CEERTS Project:

Assumptions:

- Estimated Newly-Proposed CEERTS Project = $100M
- Total Estimated Newly-Proposed CEERTS Avoided Project Cost Benefit = $125M
  - Total Estimated Previously-Approved CEERTS Project Cost Benefit = $75M
  - Enrolled Transmission Provider C Estimated Avoided Project Cost Benefit = $50M

Newly-Proposed CEERTS Project Cost Allocation:

- (Percentages in example are rounded to nearest whole percentage)
  - Previously-Approved CEERTS Project Enrolled Transmission Providers (A & B) = ($75M / $125) = 60%
    - This 60% of the cost responsibility would be allocated to Enrolled Transmission Providers A & B:
      - Enrolled Transmission Provider A = 60% * 50% = 30%
      - Enrolled Transmission Provider B = 60% * 50% = 30%
  - Enrolled Transmission Provider C = ($50M / $125M) = 40%

Appendix 5 to Attachment K

Dispute Resolution Procedures
for Disputes Arising from the
FRCC Regional Transmission Planning Process
and/or Cost Allocation Thereunder

Section 1 Dispute Resolution.

These procedures are established for the equitable, efficient and expeditious resolution of disputes arising under this Attachment K from the *FRCC Regional Transmission Planning Process* and/or cost allocation thereunder. These procedures shall be used to resolve such disputes between FRCC Members, between an FRCC Member (hereafter "Member") and a consenting non-member, or between FRCC and any Member or consenting non-member (any of the foregoing being referred to hereinafter as a "party"), arising from an act or omission by FRCC, or from an act or omission by a party in its capacity as a Member. Among other things these procedures do not apply to disputes that are covered by the dispute resolution provisions of the FRCC Compliance Monitoring and Enforcement Program (Exhibit D to the Delegation Agreement between FRCC and NERC) or other NERC dispute resolution provisions, disputes subject to other dispute resolution procedures set forth in Members' Open Access Transmission Tariffs, and/or disputes arising under Appendix 1 of this Attachment K, and do not supersede, unless agreed to by the parties, any dispute resolution agreement between the parties applicable to a dispute .

These procedures supersede the dispute resolution provisions in the *FRCC Regional Transmission Planning Process*.

Multiple parties with the same or substantially similar interests may be joined in the same proceeding.

The parties are strongly encouraged to take part in the complete process described herein prior to initiation of judicial proceedings or the utilization of other external dispute resolution processes, but the use of any of the steps of the process shall not be a required condition for the initiation of judicial or regulatory proceedings or the utilization of other external dispute resolution processes, including the filing of a complaint pursuant to Section 206 of the Federal Power Act.

FRCC shall be involved in the administration of a proceeding as provided in section 5 to coordinate with the parties to facilitate the resolution of the dispute, and to provide personnel, coordination, and meeting and other facilities as specified herein.

Section 2 Initiation.

Any Member, consenting non-member or FRCC (the "Invoking Party") may initiate these dispute resolution procedures by making a request in writing to the FRCC President with a copy to all other parties to the dispute; provided, however, that if FRCC initiates the dispute, FRCC shall make a request in writing to the Chair of the FRCC Board of Directors, with a copy to the FRCC Vice Chair and all other parties. The copy of the dispute resolution request for each party shall be sent to and accepted by the Member representative appointed in accordance with Section 1.7 of the FRCC Bylaws. The FRCC President will inform the FRCC Board of Directors of the initiation of any dispute resolution proceedings, and the docket number and title assigned to the dispute. The request must contain:

(a) a statement of the issues in dispute;

(b) the position of the party on each of the issues;

(c) the relief sought by the party;

(d) an explanation of the asserted right to such relief under an applicable tariff, contract or other legal standard or obligation;

(e) the dispute resolution step under Section 4 at which the party proposes to begin; and

(f) any proposed modifications or specific additions to the proceedings described in this Dispute Resolution Procedure by which the dispute may be resolved.

Each person or entity identified as party to the dispute (a "Noticed Party") shall submit a response to the request to the FRCC President, the FRCC Chair and FRCC Vice Chair, and each other party to the dispute (the "Dispute Response"). Each response shall set forth the position of the party on each of the points identified above. A party shall have 20 business days from its receipt of the request to submit its Dispute Response.

Section 3 Dispute Resolution Process.

The dispute resolution process described herein shall be conducted and administered in accordance with the FRCC Bylaws and such other FRCC governing documents as may be relevant to the proceedings. These dispute resolution procedures outline a step-by-step process for the resolution of disputes. Parties are permitted to skip steps in the dispute resolution process by mutual agreement, or as specified in the procedures for each step.

Section 4 Resolution Steps.

The four steps in the dispute resolution process are:

(a) <u>Step 1—Settlement Proceeding</u>: (i) Step 1 is a proceeding in which the parties shall meet in a good faith effort to resolve the dispute by mutual agreement ("Settlement Proceeding"). FRCC shall provide administrative support, such as making available meeting space, as requested by the parties. The parties shall be represented at settlement discussions by a person with full authority to resolve the dispute. A final resolution may be subject to corporate or regulatory or other government approvals, the requirements for which shall be disclosed by any party subject to an approval prior to agreement on a final resolution.

(ii) In the event that the parties cannot resolve their dispute in ninety (90) days from the submission of the dispute resolution request, or such later date as may be agreed to by the parties, the dispute shall proceed to the next step in the dispute resolution process. At any time after thirty (30) days from the submission of the dispute resolution request the parties may mutually agree to end the process. Any statement relating to the dispute by any party during the course of or relating to the Settlement Proceeding may not be cited or offered into evidence for any purpose in any external proceeding by any party.

(b) Step 2—Mediation Proceeding: (i) Step 2 is a proceeding to assist the parties through active participation by a mediator in joint discussions and negotiations through which the parties attempt to resolve the dispute by mutual agreement ("Mediation Proceeding"). The Mediation Proceeding shall be conducted by an independent mediator selected and mutually agreed upon by the parties ("Mediator"). A Mediator shall have no affiliation with, financial or other interest in, or prior employment with any party or any of their parents, subsidiaries or affiliates, and shall have knowledge and experience relevant to the subject matter of the dispute. In the event that the parties cannot agree on a Mediator within 10 days following the termination of the Settlement Proceeding, the President of FRCC shall select a Mediator; provided, however, that if FRCC is a party the Mediator shall be selected by the FRCC Chair, unless the FRCC Chair is an officer or employee of a party, in which case the selection shall be made by the FRCC Vice Chair. At the request of the Mediator, the parties shall be represented at a mediation session by a person with full authority to resolve the dispute. A final resolution may be subject to corporate or regulatory or other government approvals, the requirements for which shall be disclosed by any party subject to an approval prior to agreement on a final resolution.

(ii) The Mediator shall not issue specific recommendations on resolution of the dispute or otherwise opine on the merits of the dispute except at the request of the parties. A party may request the Mediator to offer his or her views on the merits or any other aspect of the dispute to that party individually on a confidential basis. Any recommendation, opinion or other statement expressed by the Mediator or any party relating to the dispute during the course of or relating to the Mediation Proceeding shall be offered solely for purposes of resolution of the Mediation Proceeding, and may not be cited or offered into evidence for any purpose in any external proceeding by any party.

(iii) In the event that the parties cannot resolve their dispute in ninety (90) days from the selection of the Mediator, or such later date as may be agreed to by the parties with the concurrence of the Mediator, the dispute shall then proceed to the next step in the dispute resolution process. At any time after sixty (60) days from selection of the Mediator, the parties may mutually agree to end the process, or a party may request the Mediator to determine and declare that the Mediation Proceeding is at an impasse. If the Mediator determines that the Mediation Proceeding is not likely to result in a resolution of the dispute, the Mediator shall declare the Mediation Proceeding at an impasse, and if so the dispute shall proceed to the next step in the dispute resolution process.

(c) Step 3—Arbitration Proceeding: (i) Step 3 is a non-binding arbitration in which an arbitrator or an arbitration panel shall receive evidence from each disputing party on factual matters, and hear arguments, relating to the issues in dispute, make written findings and conclusions of fact and law, and issue specific recommendations, based on those findings and conclusions, for resolution of each issue in dispute ("Arbitration Proceeding"). Initiation of an Arbitration Proceeding shall require the mutual agreement of the parties. The Arbitration

Proceeding shall be conducted before a single arbitrator selected by the parties. Alternatively, the parties may agree to have the Arbitration Proceeding conducted by a panel of three arbitrators, with one designated by the Invoking Party or Parties, one designated by the Noticed Party or Parties, and a third selected by the two arbitrators designated by the parties. The parties may by mutual agreement engage a firm specializing in alternative dispute resolution to administer the Arbitration Proceeding, or may invoke the assistance of the Federal Energy

Regulatory Commission's Dispute Resolution Service. Arbitrators shall have no affiliation with, financial or other interest in, or prior employment with any party or any of their parents, subsidiaries or affiliates, and shall have knowledge and experience relevant to the subject matter of the dispute. The parties shall have 10 business days after conclusion of or agreement to skip the Mediation Proceeding to select a single arbitrator, or to agree on the use of an arbitration panel and to make their respective arbitrator designations and to so notify the opposing party or parties, with the arbitrators so designated selecting the third arbitrator not later than five days after the last such designation. If the parties cannot agree on the selection of a single arbitrator, unless the parties agree otherwise the President of FRCC shall provide the parties with a list of not less than five candidates meeting the qualifications set forth above. The list shall summarize the qualifications of the candidates, by experience and education, to resolve the matters at issue. The parties shall convene a meeting or telephone conference call during which the parties shall alternate striking names from the list until a single name remains, the party with the first strike to be chosen by lot. If any person so selected is or becomes unwilling or unable to serve, the last

person struck from the list shall be requested to serve. Subsequent procedures shall be determined by the arbitrator or arbitration panel, upon consideration of the recommendations of the parties, who shall seek to agree on a location for the arbitration and other procedures.

(ii) The arbitrator or arbitration panel shall issue findings of fact and law and recommendations for resolution of the dispute within ninety (90) days of appointment, unless a longer period shall be agreed to by the parties with the concurrence of the arbitrator or arbitration panel.

(d) Step 4—Board Proceeding: (i) Step 4 is a proceeding conducted by the FRCC Board (Board Proceeding) to hear formal evidence on factual matters related to the issues submitted, make written findings of fact and conclusions of law, and issue a recommended award or other resolution for each issue in dispute; provided, however, that if the parties have completed an Arbitration Proceeding as specified in Step 3, the Board shall accept the arbitrator's findings of fact except to the extent that a party demonstrates to the satisfaction of the Board that one or more findings of fact are erroneous. A party shall have 30 days from the completion of the Arbitration Proceeding to make a submission to the Board, with copies to all parties, contending that any of the findings of fact by the Arbitrator are erroneous, and any other party shall have 15 days from its receipt of the submission to respond to any such submission. Other procedures and schedules for the Board Proceeding shall be established by the FRCC Board.

(ii) The FRCC Board shall vote on the appropriate resolution of the dispute in accordance with the voting procedures described in the FRCC Bylaws. The FRCC Board shall publish the results of the vote and issue recommendations for resolution of the issues in dispute within ninety (90) days of initiation of the Board Proceeding, or such longer period as may be agreed to by the parties, with the concurrence of the FRCC Board.

(e) Further Proceedings. After 30 days from completion of the dispute resolution steps described above, to the extent that the parties have not agreed to resolution of any issue in dispute a party may seek resolution of the dispute through one of the following proceedings:

(i) By agreement of the parties, binding arbitration.

(ii) A regulatory proceeding before a state or federal regulatory agency having jurisdiction of all parties and the subject matter of the dispute.

(iii) A judicial proceeding before a court of competent jurisdiction.

Nothing in this Section 4(e) shall limit the right of a party to file a complaint, at any time, with the Federal Energy Regulatory Commission pursuant to Section 206 of the Federal Power Act.

Section 5 Administration.

The following administrative procedures apply to the dispute resolution procedures described in Section 4(a)-(d):

At each step in the process, unless the parties otherwise agree the neutral person or persons conducting the dispute resolution process shall determine meeting arrangements and formats necessary to efficiently expedite the resolution of the dispute, and shall notify the parties of these details. The parties shall seek to agree on such matters, but if after endeavoring in good faith they are unable to agree, or if they request it, the neutral authority for the proceeding shall make decisions regarding such details. The President of FRCC shall assign a member of the FRCC staff to assist those responsible for conducting the dispute resolution with the administration of the process. If the parties resolve their dispute in a proceeding prior to the Board Proceeding, the person or persons responsible for conducting the dispute resolution process shall notify the President of FRCC and the FRCC Chair of its outcome. After consultation with the parties and the individuals responsible for conducting the dispute resolution process to confirm the completion of the process described in that step, the President of FRCC, with the concurrence of the FRCC Chair if the FRCC initiated the dispute, shall discharge the persons responsible for conducting the dispute resolution process, and notify the FRCC Board of the results.

Section 6 Expenses.

The parties to the dispute shall share equally all costs for meeting locations, administrative costs, and travel and related expenses of FRCC staff members, Mediators or arbitrators administering or conducting the dispute resolution process. The parties to the dispute shall also share equally all charges for time and expenses of a Mediator, an arbitrator or an arbitration panel. The FRCC Controller shall, with the assistance of the FRCC staff members assigned to assist in the administration of the proceedings, account for these expenses. Each party to the dispute shall be responsible for its own costs and fees, including attorney fees, associated with participation in any of the proceedings described herein.

Appendix 6 to Attachment K

Examples of Cost Recovery Provisions

Example 1: per 9.4.5.A(1)

- CEERTS project where Companies A & B are incumbent enrolled transmission providers and each receive benefits from the project
- Company A is the project developer
- Company B makes a FERC-approved CIAC payment to Company A for its allocated cost and records an intangible asset in its rate base to be amortized
- Company A records CIAC as a reduction to transmission plant in service

Assumptions:	Ownership %	Initial Capital	Ongoing O&M Expense	Capital Replacements
Total CEERTS Project Cost:		$400 million	$150 million	$100 million
Company A Cost Responsibility	60%	$240 million	$90 million	$60 million
Company B Cost Responsibility	40%	$160 million	$60 million	$40 million
CIAC is not Grossed-Up for Income Taxes				

$ in Millions

Company A	Taxes Payable		Cash		Transmission Net Plant (FERC 350-359)		Depreciation Expense (FERC 403)		O & M Expense (FERC 566, 573)	
Record Initial Project cost Spending				$ 400	$ 400					
Record Receipt of CIAC			$ 160			$ 160				
Record Annual Depreciation (30 yr life)						$ 8	$ 8			
Record On-going O&M Expense ($5M Annually)				$ 150					$ 150	
Record Receipt of O&M (40%)			$ 60							$ 60
Record Replacement Capital Expenditures				$ 100	$ 100					
Record receipt of Replacement Capital Expenditures as CIAC			$ 40			$ 40				
Record Annual Depreciation on Replacement Capital (30 yr life)						$ 2	$ 2			

Company B	Cash		Intangible Net Plant (FERC 303)		Amortization Expense (FERC 404)		O & M Expense (FERC 566, 573)	
Record Initial Payment of CIAC		$ 160	$ 160					
Record Annual Amortization (30 yr life)				$ 5	$ 5			
Record On-going O&M Expense ($5M Annually x 40%)		$ 60					$ 60	
Record Replacement Capital Expenditures		$ 40	$ 40					
Record Annual Amortization on Replacement Capital (30 yr life)				$ 1	$ 1			

Appendix 6 to Attachment K

Examples of Cost Recovery Provisions

Page 2 of 3

Example 2: per 9.4.5.A(2)

- CEERTS project where Companies A & B are incumbent enrolled transmission providers and each receive benefits from the project
- Company A is the project developer and funds the entire project
- Company A files with FERC to recover its transmission revenue requirement from Company B over 30 years
- Company A reduces its transmission revenue requirements
- Company B increases its transmission revenue requirements
- Assume capital replacements are $90 million over the 30-year period
- Assume operating and maintenance expense (O&M) is $150 million over the 30-year period
- Assume total pretax return on rate base to Company A of $350 million (pretax ROR of 12%)
- Total revenue requirement due to Company A is capital, O&M, and return on capital

Assumptions:	Ownership %	Initial Capital	Ongoing O&M Expense	Capital Replacements	Return on Rate Base to Co A	
Total CEERTS Project Cost:		$400 million	$150 million	$90 million		
Company A Cost Responsibility	60%	$240 million	$90 million	$54 million		
Company B Cost Responsibility	40%	$160 million	$60 million	$36 million	$350 million	$606 due to A

$ in Millions **Company A**	Cash		Transmission Net Plant (FERC 350-359)		Depreciation Expense (FERC 403)		O & M Expense (FERC 566, 573)		Revenue (FERC 456)	
Record Project Cost Spending		$ 400	$ 400							
Record Annual Depreciation (30 yr life)				$ 13	$ 13					
Record On-going O&M Expense		$ 150					$ 150			
Record Replacement capital expenditures		$ 90	$ 90							
Record Annual Depreciation on Replacement Capital (30 yr life)				$ 3	$ 3					
Record Total Revenue Requirements from Company B	$ 606									$ 606

Company B	Cash		O & M Expense (FERC 566, 573)	
Record On-going Payment to Company A (over 30 yrs)		$ 606	$ 606	

Appendix 6 to Attachment K

Examples of Cost Recovery Provisions

Example 3: per 9.4.5.B

- CEERTS project where Companies A & B each receive benefits from the project
- Company C is a non-incumbent and the project developer and funds the entire project
- Company C files with FERC to recover its transmission revenue requirement from Company A & B over 20 years
- Company A & B increase their transmission revenue requirements
- Assume capital replacements are $90 million over the 30 year-period
- Assume operating and maintenance expense (O&M) is $150 million over the 30-year period
- Assume total pretax return on rate base to Company C of $900 million (pretax ROR of 12%)
- Total revenue requirement due to Company C is capital, O&M, and return on capital

Assumptions:	Ownership %	Initial Capital	Ongoing O&M Expense	Capital Replacements	Return on Rate Base to Co A		
Total CEERTS project cost:		$400 million	$150 million	$90 million	$900 million		
Company A cost responsibility	50%	$200 million	$75 million	$45 million	$450 million	$770	due to C
Company B cost responsibility	50%	$200 million	$75 million	$45 million	$450 million	$770	due to C

$ in Millions

Company C	Cash		Transmission Net Plant (FERC 350-359)		Depreciation Expense FERC 403		O & M Expense (FERC 566, 573)		Revenue (FERC 456)	
Record Project Cost Spending		$ 400	$ 400							
Record Annual Depreciation (30 yr life)				13	$ 13					
Record On-going O&M Expense		$ 150					$ 150			
Record Replacement Capital Expenditures		$ 90	$ 90							
Record Annual Depreciation on Replacement Capital (30 yr life)				$ 3	$ 3					
Record Total Revenue Requirements from Company A & B	$ 1,540									$1,540

Company A	Cash		O & M Expense (FERC 566, 573)	
Record on-going payment to Company C (over 30 yrs)		$ 770	$ 770	

Company B	Cash		O & M Expense (FERC 566, 573)	
Record on-going payment to Company C (over 30 yrs)		$ 770	$ 770	

ATTACHMENT A

ATTACHMENT K

TRANSMISSION PLANNING PROCESS

Transmission Provider plans for the existing and future requirements of all customers of Transmission Provider's transmission system in a coordinated, open, comparable, non-discriminatory and transparent manner both at the local and regional level. The Transmission Planning Process described herein includes Transmission Service for Transmission Provider's Native Load Customers, Network Customers, Firm Point-to-Point Transmission Customers, and Generator Interconnection Service for Interconnection Customers. The Transmission Planning Process is intended to provide transmission customers the opportunity to interact with the transmission planning personnel of the Transmission Provider in order for transmission customers to provide timely and meaningful input into the development of the transmission plan. Transmission Provider's Transmission Planning Process works in conjunction with and is an integral part of the *Florida Reliability Coordinating Council's ("FRCC") Regional Transmission Planning Process* (reference the FRCC website for this document[1]) which facilitates coordinated planning by all transmission providers, owners and stakeholders within the FRCC Region.

The FRCC is one of the North American Electric Reliability Corporation ("NERC") Regional Reliability Organizations, with responsibility for maintaining grid reliability in Peninsular Florida, east of the Apalachicola River. This region is electrically unique because it is a peninsula and is tied to the Eastern Interconnection only on one side. FRCC's members include investor owned utilities, cooperative utilities, municipal utilities, a federal power agency, power marketers, and independent power producers. The FRCC Board of Directors has the responsibility to ensure that the *FRCC Regional Transmission Planning Process* is fully implemented. The FRCC Planning Committee ("FRCC PC"), which includes representation by all FRCC members, directs the FRCC Transmission Working Group and any other supporting group, in conjunction with the FRCC Staff, to conduct the necessary studies to fully implement the *FRCC Regional Transmission Planning Process*. The descriptions of the *FRCC Regional Transmission Planning Process* set forth herein summarize the elements of that process as they relate to Transmission Provider and the principles of the Final Rule in Docket No. RM05-25-000.

The Florida Public Service Commission ("FPSC") is an integral part of the planning process by providing input, guidance, regulatory oversight and decision-making under this process. Additionally, the FPSC conducts workshops on an annual basis to review the transmission and generation expansion plans for Florida. The FPSC, under Florida law, has the authority to ensure an adequate and reliable electric system for Florida. As set forth below, Transmission Provider's Transmission Planning Process is a seamless process that fully integrates both the local and regional transmission planning and is designed to satisfy the following principles, as defined in the FERC Final Rule in Docket No. RM05-25-000: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects. Descriptions of the *FRCC Regional Transmission Planning Process* are contained herein as they relate to Transmission Provider's Transmission Planning Process.

End Notes:

1. The FRCC posts on its website at https://www.frcc.com all of the FRCC documents referenced in this Attachment K. This provides flexibility for the FRCC to change the URL addresses for individual FRCC documents without requiring the modification of tariff language.

Section 1 Coordination

1.1 Transmission Provider consults and interacts directly with its customers in providing transmission service and generator interconnection service as well as with its neighboring transmission providers, on a regular basis. A transmission customer may request and/or schedule a meeting with Transmission Provider to discuss any issue related to the provision of transmission service at any time. Transmission Provider consults and interacts with its customers any time during the study process that either the transmission customer or the Transmission Provider deem necessary and/or at various stages of the planning process (e.g., Scoping Meeting, Feasibility, System Impact and Facilities Studies). An open dialogue between the transmission customer and the Transmission Provider takes place regarding customer needs. This interaction and dialogue between the customer and Transmission Provider are further described under the Local Transmission Network Planning Process as set forth in Appendix 1 to this Attachment K. Topics such as load growth projections, planned generation resource additions/deletions, new delivery points and possible transmission alternatives are discussed. This dialogue is intended to provide timely and meaningful input and participation of customers during the early stages of development of the transmission plan. Additionally, the transmission customer shall have an opportunity to comment at any time during the evaluation process and/or when study findings (Feasibility, System Impact and Facilities Studies) are communicated by the Transmission Provider to the customer. Transmission Provider communicates with its neighboring transmission providers on a regular basis, and Transmission Provider facilitates communication and consultation between its customers and its neighboring transmission service providers/owners, specifically, if during the transmission service study process, a neighboring system's facilities are identified as being affected. This coordination process continues in a seamless manner at the local as well as the regional level, leading to each Transmission Provider providing an initial transmission plan which, when consolidated, becomes the initial regional transmission plan. The initial transmission plan submitted to the FRCC by the Transmission Provider, which results from the Local Transmission Network Planning Process as set forth in Appendix 1 to this Attachment K, will be posted by the FRCC in accordance with the FRCC Regional Transmission Planning Process (reference link to Initial Plans on the FRCC website). This initial transmission plan is reviewed by the FRCC as well as all interested transmission customers/users. The Transmission Provider relies on the FRCC Committee process to finalize its initial transmission plan as submitted to the FRCC. In addition to transmission customers/users being provided timely and meaningful input and participation during the planning process with the Transmission Provider, the transmission customers/users are also given an additional opportunity to raise any issues, concerns or minority opinions that they believe have not been adequately addressed by any Transmission Providers' initial transmission plan submittal during the FRCC review process. This FRCC review process normally commences shortly after the submittal of the Ten Year Site Plans to the FPSC on April 1 of each year. Once issues raised by interested stakeholders are addressed, including consideration of proposed "Cost Effective or Efficient Regional Transmission Solutions" ("CEERTS") projects as set forth in section 1.2 below, the FRCC PC approves the proposed regional transmission plan and presents it to the FRCC Board for approval. Upon approval by the Board, which is expected in February of each year, the FRCC sends the final regional transmission plan to the FPSC. Unresolved issues may be resolved under the Dispute Resolution Procedures in Appendix 5.

1.2 CEERTS Projects

1.2.1 This section 1.2 sets forth provisions for consideration of proposed CEERTS projects in the regional transmission planning process in which Transmission Provider participates and applies to reliability, economic and public policy regional transmission projects. As discussed above, the FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The process results in a Board-approved regional plan. The biennial transmission planning process, in which CEERTS projects are identified, evaluated, and considered for regional cost allocation, contains several steps in which the FRCC Board is kept informed and must act in order to keep the process moving forward. The FRCC Board typically meets at least four times per year. If a regular meeting of the Board is not scheduled within the timeframes specified for the evaluation of a CEERTS project, special meetings of the Board will be called by the Chair, as needed, in order to meet the scheduled milestones for CEERTS project evaluation within the biennial transmission planning process timeline.

As set forth herein, the Transmission Provider, in collaboration with other transmission providers, FRCC staff, and other FRCC members, shall identify and evaluate whether there are more efficient or cost-effective regional transmission solutions to regional transmission needs relative to the transmission facilities in the initial regional transmission plan. The regional analysis shall utilize the standards, criteria, rules, tools, data, models, methods and studies of the local transmission plans, as delineated in Appendix 1, supplemented as necessary for the regional analysis as set forth herein. The regional analysis shall determine if there is a solution meeting CEERTS project criteria under section 1.2.3.

The regional analysis shall include consideration of potential transmission solutions to transmission needs driven by public policy requirements, as such needs are identified pursuant to section 11. The provisions for stakeholder involvement and input in the regional transmission plan, and ability to propose CEERTS projects on their own initiative, as set forth in this section 1.2, are fully applicable to potential transmission solutions to transmission public policy needs driven by public policy requirements.

1.2.2 Any entity desiring to propose a CEERTS project for regional cost allocation must submit such a CEERTS project to the FRCC no later than June 1st of the first year of the biennial regional projects planning cycle. The entity proposing a CEERTS project is referred to herein as the project sponsor. The project sponsor for a CEERTS project need not be the project developer for that project.

In addition to the right of individual entities to submit potential CEERTS projects, Transmission Provider shall participate with other transmission providers and other interested entities, through the FRCC PC, in the identification and evaluation of potential CEERTS projects for submission. The FRCC PC, or a designated subcommittee thereof, shall proactively seek out potential CEERTS projects from its analysis of the most recent Board-approved plan. This will occur during the period February through April of the first year of the biennial regional projects planning cycle. The general steps of the process are as follows:

A. Gather all relevant information relating to the most recent Board-approved plan (e.g., Final Project Information Form, approved Long Range Study, early project suggestions from interested entities); and request and collect all necessary supplemental information from transmission providers and other entities (e.g., project details and cost estimates for projects identified for potential displacement, list of potentially feasible projects not selected in the initial regional transmission plan).

B. Analyze the current plan information to identify potential opportunities for CEERTS projects. Seek justification for remedies that do not have projects planned, and synergies with the planned projects that potentially could be modified, combined, or accelerated for a more cost effective or efficient regional transmission solution. The analysis will include comparative load flow studies to evaluate various potential transmission CEERTS projects. For example, comparative load flow studies will be run to identify and evaluate potential CEERTS projects that could displace transmission projects in the initial regional transmission plan.

1. If a potential CEERTS project is identified that addresses a regional reliability or economic transmission need(s) for which no transmission projects are currently planned, an analysis will be performed to identify local and/or regional alternative transmission project(s) which would also fully and appropriately address the same transmission need(s). These local and/or regional alternative transmission project(s) will be identified through comparative load flow studies. The alternative project(s) will be used to determine the Total Estimated Alternative Project Cost Benefit in the CEERTS Project Cost-Benefit Analysis described in section 1.2.9.C.

2. If a potential regional public policy transmission need has been identified for which no transmission projects are currently planned and for which no CEERTS project has otherwise been submitted for evaluation, an analysis will be performed to identify a potential CEERTS project that would satisfy that regional public policy transmission need in a least-cost manner by evaluating various potential transmission project alternatives.

C. Develop potential CEERTS project alternatives and solicit project sponsorship from enrolled transmission providers and other entities which may have an interest in sponsoring potential CEERTS projects.

1. A potential CEERTS project developed by this process will contain the following minimum set of transmission project information:

   a) General description of the transmission facilities being proposed;

   b) General path of the transmission lines; and

   c) Transmission systems that would interconnect with the potential CEERTS project.

2. The FRCC shall post a notice on its website of any potential CEERTS projects identified through this process. Notice would be posted by May 1 of the first year of the biennial regional projects planning cycle to provide time for meeting sponsorship requirements by June 1.

3. Each identified potential CEERTS project will require at least one sponsor in order to be submitted to the FRCC for consideration. Multiple sponsors of the same project will be considered joint sponsors and shall equally share the required $100,000 deposit unless the sponsors otherwise mutually agree to a different sharing of the deposit. Potential CEERTS projects identified in this process shall not have competing sponsors for the same project. An entity that is not a sponsor or joint sponsor of a potential CEERTS project shall not be eligible to be a developer of that project unless the sponsors discontinue development of that project.

4. The sponsor or joint sponsors shall submit the potential CEERTS project for consideration in the first year of the biennial regional projects planning cycle.

1.2.3 To be eligible for approval by the FRCC Board for inclusion in the regional plan, a proposed CEERTS project must meet these threshold criteria:

A. Be a transmission line 230 kV or higher and 15 miles or longer; or be a substation flexible AC transmission system ("FACTS") device, e.g., series compensation or static var compensator, designed to operate at 230 kV or more; and

B. Be materially different from projects already in the regional plan. For purposes of this section, the FRCC will consider a CEERTS project to be materially different from another CEERTS project if it displaces a different local project or projects or is not considered a minor adjustment to an existing local or CEERTS project that it is displacing. Minor adjustments could include changes in equipment size, different terminal bus arrangement, or a slight change in route.

Local transmission facilities located solely within a Transmission Provider's footprint (e.g. Control Area) that are not selected in the regional transmission plan for purposes of cost allocation cannot qualify as CEERTS projects. Such facilities are the responsibility of the Transmission Provider to meet reliability needs and/or other obligations within its retail distribution service territory or footprint.

1.2.4 A CEERTS project submittal must include the following elements (to be provided in the context of the most current FRCC Board-approved regional transmission plan):

A. Those project sponsors that do not also intend to be a project developer must submit sufficient information related to the proposed CEERTS project that will permit the potential CEERTS project to be adequately considered within the FRCC regional transmission planning process. Below is the minimum set of information that must be submitted:

1. General description of the transmission facilities being proposed;

2. General path of the transmission lines; and

3. Transmission systems that would interconnect with the proposed CEERTS project.

B. Those project sponsors that intend to be the project developer shall so indicate and shall submit the following information:

1. Transmission project technical information:

a) Description of the transmission facilities being proposed (*e.g.*, voltage levels);

b) General path of the transmission lines; and

c) Interconnection points with the existing transmission system.

2. A cost estimate and a recommended in-service date for the project. A project developer may also submit a demonstration of its cost containment capabilities, including any binding agreement to accept a cost cap for the developer's cost of the transmission project if it is selected as a CEERTS project.

3. If the project sponsor is an incumbent, it must indicate which funding option set forth in section 9.4.5.A it intends to select.

4. A high-level summary of who will own, operate and maintain the CEERTS project, to the extent available.

C. A project sponsor may also submit any studies and analysis it performed to support its proposed CEERTS project, including the below:

1. Reliability impact assessment.

2. Load flow analysis that demonstrates performance utilizing the FRCC load flow model. The sponsor, if not an FRCC member, may obtain this model upon request from the FRCC ("Request for Florida Reliability Coordinating Council (FRCC) Transmission Information" document is posted on the FRCC website).

3. Identification of projects in the regional transmission plan that would be affected or avoided as well as any additional projects that may be required. A demonstration through a technical evaluation process that the CEERTS project is equal to or superior to avoided projects from the current regional transmission plan.

D. A deposit of $100,000 shall be submitted by the project sponsor at the time the project is submitted (*e.g.*, June 1st of the biennial regional projects planning cycle) for each CEERTS project. This deposit will be used for FRCC internal labor costs for analysis of the project as well as any out-of-pocket expenses such as for independent consultants (unexpended amounts shall be refunded, with interest, to the project sponsor). The actual costs incurred by the FRCC to analyze the CEERTS project will be borne by the project sponsor and the deposit will be trued up based on the documented cost of the analysis. An accounting of the actual costs of the CEERTS project analysis including an explanation of how the costs were calculated will be provided to the project sponsor after the analysis has been completed. Any disputes regarding the accounting for specific deposits will be addressed through the Dispute Resolution Procedures in Appendix 5.

1.2.5 During the 30-45 days following the submittals under section 1.2.2, the FRCC PC shall review the project sponsor submittals and ensure that they meet the threshold criteria in section 1.2.3 and the minimum requirements in section 1.2.4. If a submittal is incomplete, the FRCC PC shall inform the CEERTS sponsor in writing within 15 days after the next regularly scheduled FRCC PC meeting of the specific deficiency(ies), and the CEERTS sponsor shall be given an opportunity, within 30 days, to submit the information required for a complete submittal. This may be referred to as Step 1.

1.2.6 At the next FRCC Board meeting following the review in section 1.2.5, the FRCC PC shall provide an update to the FRCC Board related to all projects that have been submitted and deemed complete. The FRCC PC shall post this information on the FRCC website (subject to any posting restrictions to protect CEII or other confidential information). This may be referred to as Step 2. At that time, the FRCC PC shall also post on the FRCC website (subject to any posting restrictions to protect CEII or other confidential information) any determination that a proposed CEERTS project is not materially different from a project or projects already in the regional plan. Such posting will include an explanation of the basis for the determination that the proposed CEERTS project is not materially different.

1.2.7 During the succeeding three to five months following the FRCC Board meeting in section 1.2.6, for those CEERTS projects that cleared sections 1.2.3 through 1.2.5 above, the FRCC PC, together with an independent consultant, will conduct a technical analysis for the purpose of either developing CEERTS project information or validating CEERTS project information and analysis provided by the sponsor. Such analysis will be performed in a manner consistent with other technical analyses performed by the FRCC PC. This may be referred to as Step 3.

A. The development/validation process will either develop the needed CEERTS project parameters or validate the information and analysis provided by the sponsor. This analysis will examine the following:

1. Transmission project technical information:

a) Description of the transmission facilities being proposed (*e.g.*, voltage levels);

b) General path of the transmission lines; and

c) Interconnection points with the existing transmission system.

2. Load flow analysis that demonstrates adequate NERC Reliability Standards performance utilizing the FRCC load flow model;

3. Whether it can be demonstrated through a technical evaluation process that the CEERTS project is equal to or superior to avoided projects from the current regional transmission plan or equal to or superior to the alternative transmission project(s) that address(es) the same transmission need(s), which alternative must be identified if there are no transmission projects currently planned for the relevant transmission need(s) (see section 1.2.2.B);

    a) The FRCC PC shall verify that the proposed CEERTS project addresses transmission need(s) for which there are no transmission projects currently planned, and that the alternative project(s) to the CEERTS project could also meet such need(s). After the alternative project(s) are verified to meet such needs, the FRCC PC shall request that the entities responsible for the alternative project(s) provide cost information to the FRCC PC to be used in the FRCC PC's analysis;

4. Identification of projects in the regional transmission plan that would be affected or avoided as well as any additional projects that may be required.

    a) The FRCC PC shall request that the entities responsible for the existing project(s) that could be impacted by the proposed CEERTS project, or entities who would be required to implement additional local projects provide cost information to the FRCC PC to be used in their analysis;

5. Cost estimate for the proposed CEERTS project; and

6. In-service date for the project.

B. The FRCC PC will also consider any proposed non-transmission alternatives on a comparable basis with the CEERTS project, as described in section 5.

C. The FRCC PC will provide the CEERTS sponsor and stakeholders an opportunity to review and provide input on a report that includes its findings from the technical analysis performed, and then the report will be provided to the FRCC Board with a recommendation as to whether the proposed CEERTS project should proceed to the next evaluation step in section 1.2.8 below. The CEERTS sponsor and stakeholders shall be given 15 days to provide written comments on the report to the FRCC Board following the date on which the FRCC PC provides the report and its recommendations to the Board.

1.2.8 Over a period of two to three months from receipt of the FRCC PC report and any comments on the report provided by the CEERTS sponsor and stakeholders pursuant to section 1.2.7.C, the FRCC Board will review the FRCC PC report and any comments received and determine if the CEERTS project should proceed to the next evaluation step as described in section 1.2.9 below. The CEERTS sponsor shall be invited to be present and participate in any FRCC Board meeting that addresses the FRCC PC report in order to answer questions and to present its views regarding the CEERTS project and the FRCC PC report. If a CEERTS sponsor does not agree with the FRCC Board's determination, then the Dispute Resolution Procedures in Appendix 5 are available for use by the CEERTS sponsor. This may be referred to as Step 4.

1.2.9 Over a period of two to four months from FRCC Board approval of the continuation of the CEERTS project evaluation in section 1.2.8, the process described below will be performed by the FRCC PC under the direction of the FRCC Board. This may be referred to as Step 5.

A. A meeting will be organized by the FRCC PC to provide the CEERTS sponsor an opportunity to fully describe its proposed CEERTS project. This meeting is the venue to fully discuss the CEERTS project, taking into account the technical analysis performed by the FRCC PC, as well as any potential revisions, including transmission technical aspects, transmission project costs, and affected projects. This meeting also provides the opportunity for potentially affected transmission providers to discuss these matters. If no developer is a sponsor of the proposed project, then this meeting also provides an opportunity for potential developers to express interest in being considered as the developer of the CEERTS project (if no entity expresses interest as the project developer then the project will not move forward and the projects in the regional plan that would have been avoided by the CEERTS project will remain in the regional plan). If multiple qualified project developers express an interest in developing a CEERTS project for which the sponsor does not plan to be the developer, then such developers must each submit, within the 30 days following the meeting held pursuant to this section 1.2.9.A, the project information identified in section 1.2.4.B.2 through 1.2.4.B.4 and these project developer proposals will be evaluated in the remainder of the steps identified in sections 1.2.9 and 1.2.10. This forum will enable the CEERTS project to be fully reviewed by all affected parties.

B. The FRCC PC will consider the proposed project in light of the criteria set forth in sections 1.2.7.A. and 1.2.7.B above and as set forth below.

1. A cost-benefit analysis must be performed in accordance with section 1.2.9.C for reliability/economic projects by an independent

consultant. If the result of this analysis is a benefit-to-cost ratio of greater than 1.00, the CEERTS project will move forward in the process.

2. For a project proposed to meet a public policy transmission need that requires a solution, as verified by the FRCC PC under section 11, the FRCC PC will determine whether the proposed CEERTS project meets the public policy transmission needs identified. There is no cost-benefit analysis performed, except for the validation of the CEERTS project being the least-cost solution. The CEERTS project may be the only solution proposed, in which case it would be accepted in accordance with the project sponsorship model being used within the FRCC. However, in the event there are equally effective alternative CEERTS project solutions that have been proposed to satisfy the public policy transmission needs, then the least-cost CEERTS project would be selected. The total estimated cost of the CEERTS public policy project is determined by the methodology set forth in section 1.2.9.C.4.

C. CEERTS Project Cost-Benefit Analysis

An independent consultant will be retained to perform a cost-benefit analysis and will issue a written report of findings to the FRCC PC for sponsor and stakeholder review as set forth in section 1.2.9.D. The independent consultant will determine if the benefit-to-cost ratio, which is the sum of the "Total Estimated Avoided Project Cost Benefit," "Total Estimated Alternative Projects Cost Benefit" and "Total Estimated Transmission Line Loss Value Benefit" divided by the "Estimated CEERTS Project Cost," is greater than 1.0.

Such analysis will consider estimated costs and benefits for the 10-year period of the planning horizon that is used to prepare the regional transmission plan under development at the time the analysis is prepared plus an additional, sequential 10-year period (the "20-year period"). Levelized annual costs and benefits to determine the appropriate revenue requirements will be used and deemed appropriate.

1. Total Estimated Avoided Project Cost Benefit

The Estimated Avoided Project Cost Benefit for each enrolled transmission provider in the FRCC that has one or more projects being displaced by a CEERTS project will be determined by the independent consultant in the below manner. A CEERTS project that was previously selected and included in the most recent Board-approved transmission plan may be displaced by a newly-proposed CEERTS project. If a newly-proposed CEERTS project would displace a previously-approved

CEERTS project, the portion of the costs of the newly-proposed CEERTS project associated with the benefits calculated using the costs of the displaced previously-approved CEERTS project would be allocated to the enrolled transmission providers that were allocated the costs for the previously-approved CEERTS project (see Appendix 4, Example 4 for a hypothetical example of this cost allocation process).

> Each enrolled transmission provider that has one or more projects being displaced is considered a beneficiary of the proposed transmission facility(ies) and will develop an original installed capital cost estimate for each project being displaced and indicate in what year each such project would be projected to be in service.
>
> The independent consultant will review each enrolled transmission provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.
>
> The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate, depending on which will be used for further calculations, for each year that the displaced project would have been expected to be in service during the 20-year period, but for the CEERTS project. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the enrolled transmission provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.
>
> The net present value of the estimated annual revenue requirements for each project will be determined using the average discount rate of enrolled transmission providers weighted by their total capitalization (Enrolled TP Discount Rate). Each enrolled transmission provider will provide its discount rate and total capitalization to the independent consultant for purposes of this calculation. Such net present value will be the "TP Estimated Avoided Project Cost Benefit" for each enrolled transmission provider's displaced project(s).

All such TP Estimated Avoided Project Cost Benefits will be summed to determine the Total Estimated Avoided Project Cost Benefit.

2. Total Estimated Alternative Projects Cost Benefit

The Estimated Alternative Project Cost Benefit for each enrolled transmission provider in the FRCC that has one or more alternative projects for which a CEERTS project addresses a need for which there are no transmission projects currently planned will be determined by the independent consultant in the below manner. These projects will include those alternative transmission projects to a CEERTS project that were identified under section 1.2.2.B.1:

Each enrolled transmission provider that has one or more alternative projects is considered a beneficiary of the proposed transmission facility(ies) and will develop an original installed capital cost estimate for each alternative project and indicate in what year each such project would be needed to be in service.

The independent consultant will review each enrolled transmission provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate, depending on which will be used for further calculations, for each year that the alternative project would have been expected to be in service during the 20-year period, but for the CEERTS project. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the enrolled transmission provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements for each project will be determined using the average discount rate of enrolled transmission providers weighted by their total capitalization (Enrolled TP Discount Rate). Each enrolled transmission provider will provide its discount rate and total capitalization to the independent consultant for purposes of this calculation. Such net present value will be the "TP Estimated Alternative Project Cost Benefit" for each enrolled transmission provider's displaced project(s).

All such TP Estimated Alternative Project Cost Benefits will be summed to determine the Total Estimated Alternative Project Cost Benefit.

3. Total Estimated Transmission Line Loss Value Benefit

The Total Estimated Transmission Line Loss Value Benefit is calculated for each enrolled transmission provider by the independent consultant as follows:

The change in transmission losses caused by the CEERTS project will be determined by the FRCC PC.

The FRCC PC will run simulations of the approved transmission plan with all projects, adjusted (if necessary) to include the alternative transmission projects that were identified that would have been needed to satisfy a transmission need for which no transmission projects are in the current transmission plan (see section 1.2.2.B), to establish base transmission losses for each enrolled transmission provider represented in the plan over the planning horizon. Base case losses will be determined for the years during which the CEERTS project is expected to be in service during the planning horizon, under both peak and off-peak conditions.

The approved transmission plan will then be modified to (1) include a proposed CEERTS project; (2) remove all alternative transmission projects; and (3) adjust or remove any affected or avoided transmission projects in the approved transmission plan as well as add any additional projects that would be required (see section 1.2.7.A.4) (after verifying that all reliability requirements are met) with the appropriate in-service dates. The modified plan is then analyzed for losses. The CEERTS case losses are determined for each enrolled transmission provider represented in the plan for the years during which the CEERTS project is expected to be in service during the planning horizon, at both peak and off-peak conditions. Enrolled transmission providers with reduced losses are beneficiaries of the CEERTS project.

The change in losses for year 10 of the planning horizon will be held constant for years 11-20 of the 20-year period. The change in losses (whether negative or positive) in each year that the CEERTS project is in service for the 20-year period is determined for each enrolled transmission provider.

The value of the change in losses for each enrolled transmission provider will be determined by the independent consultant as follows:

The independent consultant will use fuel cost and heat rate data from the U.S. Energy Information Administration ("EIA") to value losses.

The net present value of the value of losses will be determined for each enrolled transmission provider using the Enrolled TP Discount Rate.

Such net present value will be the "TP Estimated Transmission Line Loss Value Benefit."

The TP Estimated Transmission Line Loss Value Benefit for each enrolled transmission provider will be summed to determine the Total Estimated Transmission Line Loss Value Benefit.

4. Estimated CEERTS Project Cost

The Estimated CEERTS Project Cost is determined using the following formula:

Estimated CEERTS Project Cost = Estimated Developer Cost + Total Estimated Related Local Project Costs + Total Estimated Displacement Costs

The Estimated Developer Cost will be determined by the independent consultant as follows:

The developer of a CEERTS project will provide an original installed capital cost estimate for the developer's project and indicate which year the project is expected to be in service.

The independent consultant will review the developer's original cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate for the developer's project, depending on which will be used for further calculations, for the years during which the CEERTS project is expected to be in service during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the rates of return on equity approved by FERC for the developer or its affiliates (if any); commitments regarding incentive rates; proposed weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements will be determined using the Enrolled TP Discount Rate. The net present value of these estimated annual revenue requirements shall be the Estimated Developer Cost.

The Total Estimated Related Local Project Cost will be determined as follows by the independent consultant:

Each enrolled transmission provider that will need to construct a local project to implement the CEERTS project will develop an original installed capital cost estimate for each such related local project and indicate what year such project is projected to be in service.

The independent consultant will review the enrolled transmission provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate for each year that the local project is expected to be in service during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the enrolled transmission provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirement for each local project will be determined using the Enrolled TP Discount Rate. Such net present value will be the TP Estimated Avoided Project Cost for the displaced project.

All TP Estimated Related Local Project Costs will be summed to determine the Total Estimated Related Local Project Cost.

The calculation of Total Estimated Displacement Cost will be performed by the independent consultant as follows:

Any enrolled transmission provider that has incurred, or expects to incur, costs associated with a project that is being displaced by a CEERTS project will provide an accounting to the independent consultant as to the level of its actual and expected expenditure on any displaced projects and any planned mitigation of such expenditures. The independent consultant will review the displacement cost estimate. The independent consultant will estimate the level of displacement cost that the enrolled transmission provider that has expended funds on a displaced project will recover by assuming that the enrolled transmission provider will be permitted to recover 100% of such displacement costs. The independent consultant will calculate an annual transmission revenue requirement associated with the displacement cost estimate for each year so that the displacement costs would be recovered during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions and will describe such relevant factors and assumptions used in the report. The net present value of the estimated annual revenue requirements shall be calculated using the Enrolled TP Discount Rate. Such net present value will be the Estimated Displacement Cost.

All such Estimated Displacement Costs will be summed to determine the Total Estimated Displacement Cost.

D. The FRCC PC will provide the CEERTS sponsor and stakeholders an opportunity to review and provide input on a report that includes its findings from the cost-benefit analysis performed that determined how benefits and beneficiaries were identified and applied to a proposed CEERTS project. The report will then be provided to the FRCC Board with the FRCC PC's recommendation based upon its review as set forth above. For any CEERTS public policy project(s), this report will include an explanation of why the CEERTS project(s) does or does not provide an opportunity to satisfy the public policy need. The CEERTS public policy analysis is more completely described in section 11.1. The CEERTS sponsor and stakeholders shall be given an opportunity to also provide written comments on the report to the FRCC Board. The CEERTS sponsor shall be invited to be present and participate in any FRCC Board meeting that addresses the FRCC PC report to answer questions and to present its views regarding the CEERTS project and the FRCC PC report.

E. The FRCC Board will review the FRCC PC report and any comments on the report that may be provided by the CEERTS sponsor and stakeholders and determine if the proposed CEERTS project is a more cost effective or efficient solution to regional transmission needs under applicable criteria in this section 1.2.9 and section 11.1.

F. If a CEERTS project is selected, the FRCC will perform analyses to determine whether the CEERTS project could potentially result in reliability impacts to the transmission system(s) in another transmission planning region. If a potential reliability impact is identified, the FRCC will coordinate with the public utility transmission providers in the other transmission planning region on any further evaluation. The evaluation may identify required upgrades in the other transmission planning region. The costs of those upgrades are addressed in section 9.4.6.

1.2.10 Over a period of two to three months following a decision that a CEERTS project should move forward under section 1.2.9, the following "Transmission Project Developer and Project Selection Process" will occur. This may be referred to as Step 6.

A. If the CEERTS project requires upgrades to an enrolled transmission provider's existing facilities that enrolled transmission provider retains a right-of-first refusal to build those portions of the CEERTS project. As used in this section the term "upgrade" means an improvement to, addition to, or replacement of a part of an existing transmission facility; the term does not refer to an entirely new transmission facility. Nothing herein affects an enrolled transmission provider's rights under state law with regard to its real property (including rights of way and easements).

B. If a single project sponsor is also the developer identified for a given CEERTS project, then that project sponsor/developer is accepted by default as the project developer eligible to use the regional cost allocation for that CEERTS project (subject to the qualifications review below). If there are different proposed CEERTS projects to address the same transmission need(s), then the CEERTS project will be selected based on the highest benefit-to-cost ratio as determined in section 1.2.9.C and once a project sponsor/developer's proposed CEERTS project is selected in the regional transmission plan, that project sponsor/developer will also be selected as the project developer eligible to use the regional cost allocation for that CEERTS project, subject to the project developer qualifications review. CEERTS projects proposed by a single qualified project developer and selected by the FRCC Board will not be assigned to a different project developer.

C. If there are multiple project developers for the same CEERTS project, then the FRCC Board will, upon request, facilitate an opportunity for the project sponsors/developers to collaborate with each other to determine how each of the project developers may share responsibility for portions of the CEERTS project(s). If agreement is reached, then these project sponsors/developers will be selected (subject to the qualifications review below). If there is no agreement, then the project developer for the CEERTS project will be selected based on the highest benefit-to-cost ratio as determined in section 1.2.9.C.

1.2.11 Project Developer Qualifications Review

A. Project developers (both incumbent and non-incumbent project developers) that are submitting for the first time a qualification application must submit the application and a deposit of $50,000 to the FRCC along with the information identified in the Qualification Criteria as set forth in Appendix 3 of this Attachment K. The deposit will be used by the FRCC Board to fund the internal FRCC labor cost for application review, which will be documented, and expenses for the independent consultant for the review described in the next section. Any unexpended amounts from the deposit, including interest, shall be refunded to the project developer. The transmission developer will be provided with an accounting of the actual costs and how the costs were calculated. Any disputes related to the accounting for specific deposits shall be addressed under the Dispute Resolution Procedures in Appendix 5. A project developer may be a joint venture or a partnership in which case a lead representative will be designated in the qualification application. Project developers that already have been found qualified after a review by the FRCC must submit an attestation to maintain their qualification as discussed in Appendix 3. If sufficient changes, as determined by the FRCC, have been identified in the attestation by a project developer which had previously been qualified, then a deposit of $10,000 to the FRCC will be required during the attestation review process. This deposit will be handled in a similar manner as described above for the initial project developer qualification review.

B. The FRCC Board will provide for the review of the submitted qualifications by an independent consultant. The consultant fees will be paid from the deposit made when a project developer qualification application is submitted. The consultant will make a recommendation to the FRCC Board as to whether the Qualification Criteria have been met. The FRCC Board shall make, on a non-discriminatory basis, a determination as to whether the Qualification Criteria have been met. If the FRCC Board determines that the Qualification Criteria have not been met, the FRCC Board will notify the project developer of the qualification deficiencies and provide a 30-day period for the project developer to cure the deficiencies. If a project developer does not agree with the FRCC

Board's determination, then the Dispute Resolution Procedures in Appendix 5 are available for use by the project developer. The qualification process is a one-time process for each project developer, subject to the attestation review process provided for in Appendix 3.

C. The timeline for the project developer qualification review evaluation process is set forth below:

1. By January 1 of the first year of a biennial regional projects planning cycle, any potential developer that seeks to be qualified to develop CEERTS projects during this cycle must submit its qualifications to the FRCC. Biennial attestations also must be submitted at this time.

2. In January through March of the first year of a biennial regional projects planning cycle, FRCC shall coordinate the qualifications review.

3. By April 1 of the first year of a biennial regional projects planning cycle, the FRCC Board will inform developers that have submitted qualifications or attestations that they have either met the qualification criteria or the FRCC Board will identify deficiencies in the submitted qualifications/attestations.

4. From April 1 through April 30 of the first year of a biennial regional projects planning cycle, developers will have an opportunity to cure deficiencies and resubmit their modified qualifications/attestations.

5. From May 1 through May 31 of the first year of a biennial regional projects planning cycle, the FRCC Board shall reexamine the modified qualifications/attestations, make final determinations, and notify developers, FRCC members and other stakeholders.

1.2.12 Approval and Certification after Conclusion of the Project Developer Determination and Qualifications Review

A. At the next FRCC Board meeting after successful completion of the items in sections 1.2.3 through 1.2.11 above, the FRCC Board will notify the project developer to proceed with the project as it has been approved for inclusion in the regional transmission plan. It is at this point that any transmission projects currently in the regional transmission plan that are being avoided due to the new CEERTS project will be removed from the regional transmission plan. The project developer(s) shall then proceed with obtaining the necessary approvals and/or permits required to construct, own and operate the project, including certification under the Transmission Line Siting Act.

1.2.13 The FRCC PC, under the oversight of the FRCC Board, will verify that all required reliability, operational, and property rights provisions listed below are in place, or reasonably planned for, after a CEERTS project is included in the regional transmission plan pursuant to section 1.2.12. The FRCC Board will monitor such elements and progress toward such elements in determining whether a CEERTS project has been delayed or abandoned.

A. All certification and other requirements under the NERC Standards and Rules of Procedure;

B. Implementation of communications and operational control features (e.g., requirements to follow instructions of the Reliability Coordinator, Balancing Authority and/or Transmission Service Provider);

C. Responsibility for operation and maintenance ("O&M"), including any plans to turn over O&M responsibilities to another entity; and

D. Acquisition of the property rights necessary to construct the CEERTS facilities, or a reasonable expectation of the ability to acquire such rights.

1.2.14 As identified in section 1.2.2, new CEERTS projects are to be submitted by June 1 of the first year of each biennial regional projects planning cycle. The technical evaluation of a new CEERTS project will occur within approximately 12 months concurrent with the evaluation of the initial FRCC regional transmission plan, and final approval will be achieved within 19 months. This time period may be shorter for some CEERTS projects, such as where the project developer has previously satisfied qualification criteria and/or the project is relatively small in scale. Following the evaluation steps identified in this section 1.2 for a newly proposed CEERTS project, a sponsor can expect the project to be analyzed with the regional transmission plan as a tentative project in the summer or fall of the following year. For the project to remain in the regional transmission plan, the remainder of the process must be completed. For example, a new CEERTS project that was proposed by June 1 in biennial year 1 would proceed through section 1.2.7 in the fall of biennial year 1 through the winter of biennial year 2. In the spring and summer of biennial year 2, the project would progress through the items in section 1.2.9 and be tentatively added to the regional transmission plan. Successful completion of the items in sections 1.2.10 through 1.2.12 would qualify the project for final approval in December of biennial year 2, roughly 19 months after it was initially proposed. This overall schedule provides a roadmap of the projected schedule for new CEERTS project evaluation, selection, approval and ultimate reflection in the regional transmission plan within the mandatory two year (biennial) planning cycle. A particular CEERTS project submittal may benefit from schedule flexibility or shortening of process steps depending on the project's nature or complexity, availability of qualified project developer(s), or other factors. In all cases, once a CEERTS project is submitted, the FRCC will keep all parties informed of the projected schedule for project evaluation. This

CEERTS project evaluation process will fold into the overall regional transmission planning cycle, which will continue to be an annual process, that is, a regional transmission plan will continue to be developed each year. The inclusion of the CEERTS projects into the annual regional transmission plan will be in accordance with the process outlined above.

1.2.15 After a CEERTS project is approved for the regional transmission plan, the project developer shall submit to the FRCC PC a development schedule that sets forth the required steps necessary to develop and construct the project and the schedule that the developer will follow to satisfy each required step. Required steps include, but are not limited to, obtaining all regulatory approvals necessary to develop and construct the facility.

1.2.16 Status updates of a CEERTS project are required at any time when material changes to the project or schedule take place, or at least annually, and must include any revised cost estimate. If the cost estimate for a CEERTS project is substantially more than the cost estimate upon which the project was approved, the FRCC PC and FRCC Board may re-examine the cost effectiveness of the project.

1.2.17 If a CEERTS reliability-based project is abandoned by the developer the Transmission Provider(s) has a right of first refusal to complete the project to the extent it is located in the Transmission Provider's service territory. However, if the Transmission Provider decides not to complete the abandoned reliability-based CEERTS project and decides instead to propose an alternative CEERTS project, then other potential developers will be given an opportunity to propose an alternative CEERTS project to ensure that the reliability need is met. Developer evaluation and selection shall follow the steps above for a CEERTS project when first proposed. If a non-reliability-based CEERTS project is abandoned by the developer, other potential developers may offer to complete the project. Developer evaluation and selection shall follow the steps above for a CEERTS project when first proposed.

1.2.18 If a delay in the completion of a CEERTS reliability-based project potentially would cause Transmission Provider or other NERC-registered entity to violate a Reliability Standard, the NERC-registered entity shall inform the FRCC as soon as it is aware of the possibility. The FRCC PC will re-evaluate the regional transmission plan to determine if the delay in the CEERTS project requires the evaluation of alternative solutions to ensure the relevant Transmission Provider or other NERC-registered entity can continue to meet its reliability and/or other service obligations. If the FRCC PC determines that the delay in the CEERTS project would adversely affect reliability (e.g., would cause a violation of one or more NERC reliability standards), the FRCC PC will initiate a process to evaluate solutions to address the reliability concerns. The transmission providers whose system(s) are affected by these reliability concerns will be given an opportunity to propose solutions that they would implement within their service territories or footprints to address these reliability concerns, and their proposals can be evaluated as possible CEERTS projects if such transmission providers agree. The FRCC PC will fully evaluate the original CEERTS project delay along with any proposals for alternate solutions and will make a determination on how to proceed in a timely manner to ensure that the FRCC regional transmission plan supports the adequate planning for a reliable transmission system for the FRCC region. Where possible, the review of a CEERTS project delay will be included within the biennial regional transmission planning cycle. However, if the FRCC PC determines that a CEERTS project delay needs to be evaluated outside of the biennial regional projects planning cycle, the FRCC PC will notify the members and establish a schedule for the evaluation process. The FRCC PC will follow similar steps that are identified in sections 1.2.9.C and 1.2.9.D to develop a report of the results of their evaluation and provide their findings to the FRCC Board for ultimate resolution.

1.2.19 The Transmission Provider retains the right to construct local transmission projects that are not subject to regional cost allocation to meet reliability needs and/or service obligations within its retail distribution service territory or footprint.

1.2.20 Nothing herein shall adversely affect the ability of Transmission Provider to comply with state and federal law, including its service obligations under the laws and regulations of the Florida Public Service Commission and its reliability obligations under section 215 of the Federal Power Act ("FPA").

1.3 The FRCC Regional Transmission Planning Process is intended to ensure the long-term reliability, economic and public policy needs of the bulk power system in the FRCC Region (see section 1.3 endnote). An objective of the FRCC Regional Transmission Planning Process is to ensure coordination of the transmission planning activities within the FRCC Region in order to provide for the development of a reliable and economically robust transmission network in the FRCC Region. The process is intended to develop a regional transmission plan to meet the existing and future requirements of all customers/users, providers, owners, and operators of the transmission system in a coordinated, open and transparent manner.

The FRCC obtains and posts transmission owners' 10-year expansion plans on the FRCC website. All transmission providers/owners provide their long-term firm transmission service requests and generator interconnection service requests to the FRCC in a common format. The FRCC consolidates all requests for coordination purposes, and posts the consolidated requests available for viewing by all FRCC members.

Section 1.3 Endnote: Nothing in the *FRCC Regional Transmission Planning Process* is intended to limit or override rights or obligations of transmission providers, owners and/or transmission customers/users contained in any rate schedules, tariffs or binding regulatory orders issued by applicable federal, state or local agencies. In the event that a conflict arises between the FRCC process and the rights and obligations included in those rate schedules, tariffs or regulatory orders, and the conflict cannot be mutually resolved among the appropriate transmission providers, owners, or customers/users, any affected party may seek a resolution from the appropriate regulatory agencies or judicial bodies having jurisdiction.

1.3.1 This coordinated *FRCC Regional Transmission Planning Process* offers many opportunities for transmission providers to interact with customers and neighboring systems during the development of the transmission plan. The schedule of committee and working group meetings related to transmission planning is posted on the FRCC website under *FRCC Calendar*.

FRCC meeting notices, meeting minutes and documents of FRCC PC and/or FRCC Board meetings in which transmission plans or related study results are exchanged, discussed or presented are distributed by the FRCC. Detailed evaluation and analysis of the transmission providers/owners plans are conducted by the FRCC Transmission Working Group ("TWG") and Stability Working Group ("SWG") in concert with the FRCC Staff. The TWG and SWG are further described below.

1.4 A general scope of the FRCC PC and the respective working groups related to transmission planning is described below. The scope of these committees is subject to change in the future in order to address evolving needs. The members of the FRCC PC and the working groups related to transmission planning are posted on the FRCC website under *FRCC Committees.* Contact with the FRCC PC and transmission working groups can be made through FRCC staff or through the chair of the respective committee or working group.

1.4.1 The FRCC PC promotes the reliability of the Bulk Power System in the FRCC, and assesses and encourages generation and transmission adequacy. The FRCC PC reports to the Board of Directors. Rules and procedures governing the FRCC PC are posted on the FRCC website under *Rules of Procedure for FRCC Standing Committees*. Working Groups related to transmission planning reporting to the FRCC PC are described below.

1.4.2 The Transmission Working Group engages in active coordination of transmission planning within the FRCC Region under the direction of the FRCC PC , and performs the duties as required by the *FRCC Regional Transmission Planning Process*. Some of the responsibilities and objectives of the Transmission Working Group are: 1) Maintain, update and provide summer and winter database cases for the FRCC including the bulk power transmission and generation systems, projected loads and any facility additions for an eleven year period; 2) Put together the FERC Form 715 filing and EIA-411 for FRCC members, prepare State of Florida electrical maps, etc.

1.4.3 The Stability Working Group engages in the active coordination of transmission planning in the FRCC Region, assesses stability of the FRCC bulk electric system under various conditions, and provides support to the other FRCC working groups as needed. Some of the responsibilities and objectives of the Stability Working Group are: 1) Maintain and update a dynamic data base for the FRCC Region; this data base is coordinated with selected FRCC planning horizon power flow cases as required by NERC Multi-regional Modeling Working Group and other FRCC study needs; 2) Assess dynamic performance of the FRCC bulk power system in response to Category B, C and D contingencies which includes special protection systems, under frequency load shedding programs, oscillatory stability, disturbances involving separation, etc.

Section 2 Openness

2.1 Transmission Provider provides notice and schedules meetings with its transmission customers as deemed necessary by the transmission customer and/or Transmission Provider. Transmission Provider schedules meetings with its customers to interact, exchange perspectives or share findings from studies. Transmission Provider communicates and interacts with its transmission service customers on a regular basis to discuss loads, generation/network resource additions/deletions, new facility additions and upgrades, demand resource information, customers' projections of future needs, and related subjects that have an impact on the provision of transmission service to a customer. Transmission Provider provides a status update to its customers on a regular basis or at any time, if requested by a customer. Additionally, Appendix 1 to this Attachment K describes the customer and Transmission Provider interaction in the flow diagram and outlines the steps of the Local Transmission Network Planning Process.

2.2 This openness principle is also incorporated in the *FRCC Regional Transmission Planning Process* by which the Transmission Provider participates, along with other parties, in the committee and working processes at the FRCC as described below. The participants in the planning process at the FRCC are the sector representative of the FRCC PC. A list of representatives may be found on the FRCC website under the *FRCC PC Member List.* The *Rules of Procedure for FRCC Standing Committees* document on the FRCC website describes the FRCC PC structure and processes as they relate to Organization Structure, Standing Committee Representation, Standing Committee Quorum and Voting, Duties of Officers and Representatives, General Procedures for Standing Committees, FRCC Representation on NERC Committees, Procedures of Minutes of Meetings and Conduct of the Meeting. Interested entities or persons may participate in the committees via participation within one of the identified sectors (Supplier Sector, Non-Investor Owned Utility Wholesale Sector, Load Serving Entity Sector (including municipals and cooperatives), Generating Load Serving Entity Sector, Investor Owned Utility Sector, and General Sector (this sector provides for any entity or individual's participation)). Moreover, at the FRCC regional level interested entities have an opportunity to raise any special requirements that they have and believe have not been addressed at the local level. For ease of reference, the FRCC quorum and voting provisions are shown in Appendix 2 of Attachment K.

2.2.1 The FRCC meeting dates are provided in the *FRCC Calendar* document on the FRCC website and the chairs and member representatives for the various committees are posted on the FRCC website under the *FRCC Committees*. The meeting agenda for the FRCC PC is normally provided two weeks prior to the meeting to the committee members.

FRCC meeting notices, meeting minutes and documents of FRCC PC and/or FRCC Board meetings in which transmission plans or related study results will be exchanged, discussed or presented, are distributed by the FRCC.

2.2.2 The FRCC developed the *FERC Standards of Conduct Protocols* for the *FRCC* document for the purpose of ensuring proper disclosure of transmission information in accordance with FERC requirements. The primary rule is that a transmission provider must treat all transmission customers, affiliated and non-affiliated on a non-discriminatory basis, and it cannot operate its transmission system to give a preference to any transmission customer or to share non-public transmission or customer information with any transmission customer. The rules also prevent transmission function employees from sharing with their merchant employees and certain affiliates non-public transmission information about the transmission provider's transmission system or any other transmission system, which is information that the affiliated merchant employee receiving the information could use to commercial advantage. Reference the *FERC Standards of Conduct Protocols for the FRCC* posted on the FRCC website.

2.3 Customer input is included in the early stages of the development of the transmission plans, as well as during and after plan evaluation processes. Detailed evaluation and analysis of the transmission providers'/owners' plans are conducted by the FRCC Transmission Working Group and Stability Working Groups under the direction of the FRCC PC. Such evaluation and analysis provides the basis for possible changes to the transmission providers'/owners' plans that could result in a more reliable and more robust transmission system for the FRCC Region. The FRCC PC meets on a regular basis, usually monthly, with two weeks prior notice.

2.4 The FRCC conducts the FRCC planning process in an open manner in such a way that it ensures fair treatment for all customers/users, owners and operators of the transmission system. Stakeholders have access to and participate in the FRCC planning process. The committees and working groups described in this document are stakeholder groups. The FRCC PC consists of six stakeholder sectors: Suppliers, Non-Investor Owned Utility Wholesalers, Load Serving Entities, Generating Load Serving Entities, Investor Owned Utilities, and General. The rules of procedure governing the FRCC PC in conducting the *FRCC Regional Transmission Planning Process* are posted under the *Rules of Procedure for FRCC Standing Committees* on the FRCC website. The FPSC is encouraged to and does participate in the *FRCC Regional Transmission Planning Process*.

2.5 The *FRCC Regional Transmission Planning Process* provides for the overall protection of all confidential and proprietary information that is used to support the planning process. A customer, user or other interested entity may enter into a confidentiality agreement with the FRCC and/or applicable transmission provider/owner, as appropriate, to be eligible to receive transmission information that is restricted due to Critical Energy Infrastructure Information ("CEII"), security, business rules and standards and/or other limitations. The procedure for requesting this type of information is delineated at the FRCC website under the *Request of CEII Data*.

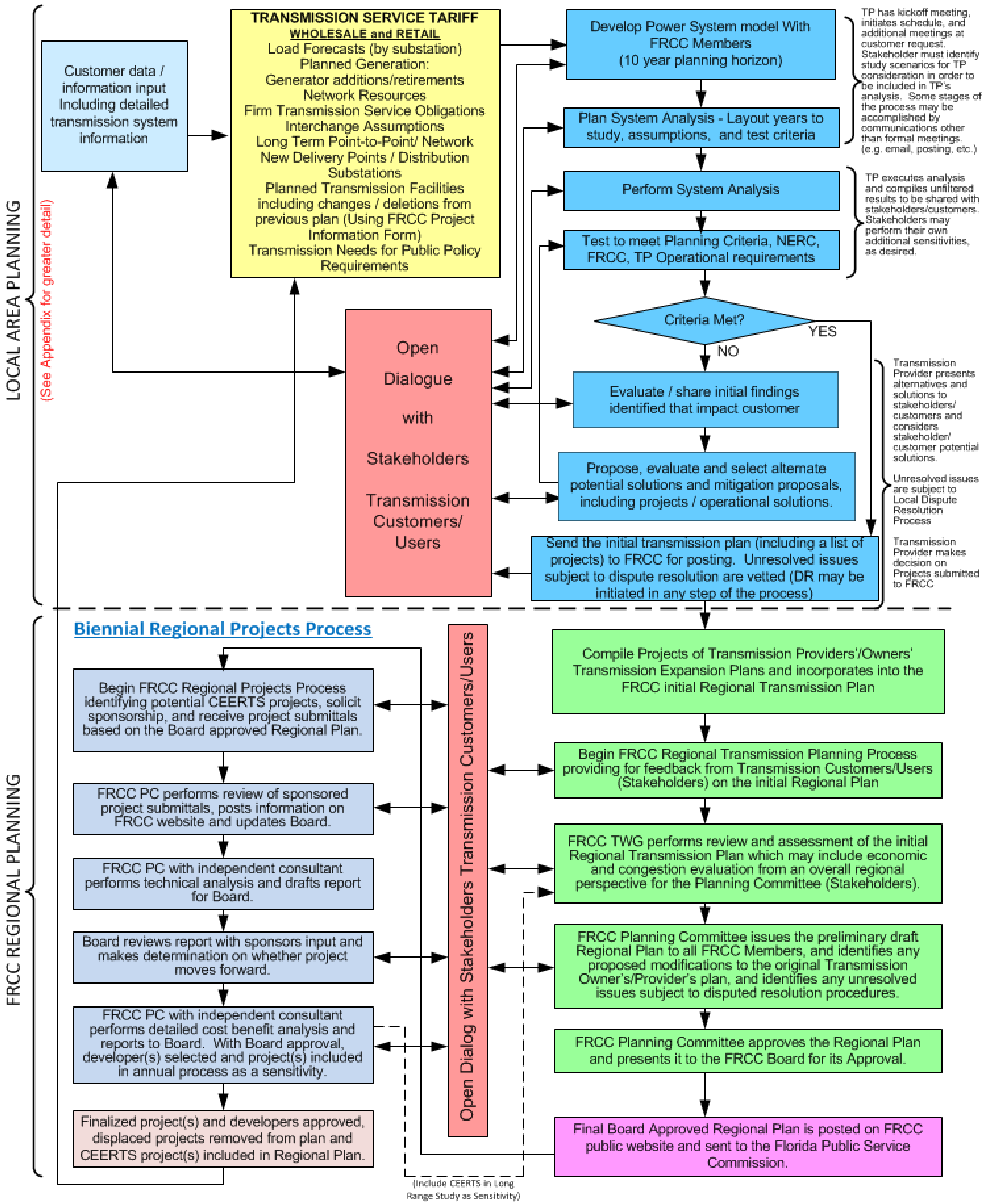
Section 3 Transparency

3.1 Transmission Provider plans its transmission system in accordance with the NERC and FRCC Planning Reliability Standards, along with Transmission Provider's own design, planning and operating criteria which it utilizes for all customers on a comparable and non-discriminatory basis. These standards/criteria are also referred to in the Transmission Provider's FERC Form 715. In addition, Transmission Provider makes available Facility Connection Requirements, Capacity Benefit Margin ("CBM") Methodology and other pertinent information used in the transmission planning process and posts this information on the Transmission Provider's OASIS website.

3.2 During the Transmission Provider's local area planning process the Transmission Provider utilizes the FRCC databanks which contain information provided by the Transmission Provider and customers of projected loads as well as all planned and committed transmission and generation projects, including upgrades, new facilities and changes to planned-in-service dates over the planning horizon, as the base case for Transmission Provider's studies. Transmission Provider makes available to a transmission service customer the underlying data, assumptions, criteria and underlying transmission plans utilized in the study process. Transmission Provider provides written descriptions of the basic methodology, criteria and processes used to develop plans. In order to get a better understanding, a transmission customer may inquire about the assumptions, data and/or underlying methods, criteria, etc. and the customer will be provided a response by the Transmission Provider's qualified technical representative. Dialogue during the study process is encouraged. The dialogue during the Transmission Provider’s local area planning process between the Transmission Provider and customers involves discussions of the initial findings that affect customers, potential alternatives including feasibility of mitigating any adverse findings, and third party impacts. Discussion of initial findings in areas of the system that affect customers is intended to communicate and validate with the customer issues or concerns identified by the Transmission Provider or conversely, issues not specifically identified by the Transmission Provider that may be of concern to the customers. As part of the process of identifying potential alternatives to mitigate any adverse issue or concern, the dialogue with the customer should facilitate the identification of the most effective solution. This dialogue during the different stages of the planning process provides for meaningful input and participation of transmission customers in the development of the transmission plan. The goal of this interaction between the Transmission Provider and customers is to develop a transmission expansion plan that meets the needs of the Transmission Provider and customer in a reliable cost effective manner. This planning process between the Transmission Provider and customers is described in the process flow diagram below and in the more detailed description of the Local Transmission Network Planning Process as set forth in Appendix 1 to this Attachment K.

3.3 An overview of the Transmission Provider's local area planning process and how it relates to the *FRCC Regional Transmission Planning Process* is shown in the flow chart below:

TRANSMISSION PROVIDER's (TP) LOCAL / REGIONAL COORDINATED TRANSMISSION NETWORK PLANNING PROCESS OVERVIEW



3.4 Once the results of the Transmission Provider's local area planning process are reflected in the *FRCC Regional Transmission Planning Process*, the FRCC seeks input and feedback from transmission customers/users for any issues or concerns that are identified and independently assesses the initial regional transmission plan from a FRCC regional perspective. A dialogue among the FRCC, transmission customers/users, and transmission owners/providers occurs to address any issues identified during this process. When the FRCC regional transmission plan has been approved by the FRCC PC, it is sent to the FRCC Board for approval. After the FRCC Board approves the FRCC regional transmission plan, it is posted on the FRCC website and sent to the FPSC. Additionally, the FRCC compiles all of the individual transmission providers'/owners' FERC Form 715s within the FRCC region, including Transmission Provider's, and files all FERC Form 715s for its members with the FERC on an annual basis.

3.5 Studies conducted pursuant to the *FRCC Regional Transmission Planning Process* utilize the applicable reliability standards and criteria of the FRCC and NERC that apply to the Bulk Power System as defined by NERC. Such studies also utilize the specific design, operating and planning criteria used by FRCC transmission providers/owners. The transmission planning criteria are available to all customers and stakeholders. Transmission planning assumptions, transmission projects/upgrades and project descriptions, scheduled in-service dates for transmission projects and the project status of upgrades will be available to all customers through the FRCC periodic project update process. The FRCC updates and distributes transmission projects/upgrades project descriptions, scheduled in-service dates, and project status on a regular basis, no less than quarterly. The FRCC also updates and distributes on a periodic basis the load flow data base. The FRCC publishes the individual transmission providers' system impact study schedules so that other potentially impacted transmission owners can assess whether they are affected and elect to participate in the study analysis. The FRCC planning studies are also distributed by the FRCC and updated as needed. All entities that have transmission projects/upgrades in the regional transmission plan shall provide updates on such projects at least annually.

3.6 The FRCC also produces the following annual reports which are submitted/available to the FPSC:

- The Regional Load and Resource Plan contains aggregate data on demand and energy, capacity and reserves, and proposed new generating unit and transmission line additions for Peninsular Florida as well as statewide.

- The Reliability Assessment is an aggregate study of generating unit availability, forced outage rates, load forecast methodologies, and gas pipeline availability.

- The Long Range Transmission Reliability Study is an assessment of the adequacy of Peninsular Florida's bulk power and transmission system. The study includes both short-term (1-5 years) detailed analysis and long-term (6-10 years) evaluation of developing trends that would require transmission additions or other corrective action. Updates on regional areas of interest and/or constraints (e.g., Central Florida) are also addressed.

Section 4 Information Exchange

4.1 Transmission Provider participates in information exchange on a regular and ongoing basis with the FRCC, neighboring utilities, and customers. Transmission customers are required to submit data for the planning process described in this Attachment K to the Transmission Provider in order for the Transmission Provider to plan for the needs of network and point-to-point customers. This data/information shall be provided by the transmission customer by no later than January 1 of each year. Such data/information includes load growth projections, planned generation resource additions/upgrades (including network resources), any demand response resources, new delivery points, new or continuation of long-term firm point-to-point transactions with specific receipt (i.e., source or electrical location of generation resources) and delivery points, (i.e., the electrical location of load or sink where the power will be delivered to), and planned transmission facilities. This data/information shall be provided over the 10 year planning horizon to the extent such information is known. Additionally, the transmission customer shall provide timely written notice of any material changes to this data/information as soon as practicable due to the possible effect on the transmission plan or the ability of the Transmission Provider to provide service.

4.2 The Transmission Provider utilizes the information provided in modeling and assessing the performance of its system in order to develop a transmission plan that meets the needs of all customers of the transmission system. The Transmission Provider exchanges information with a transmission customer to provide an opportunity for the transmission customer to evaluate the initial study findings or to propose potential alternative transmission solutions for consideration by the Transmission Provider. If the Transmission Provider and transmission customer agree that the transmission customer's recommended solution is the best overall transmission solution then such solution will be incorporated in the Transmission Provider's plan. Through this information exchange process the transmission customer has an integral role in the development of the transmission plan. This process is described in greater detail in Appendix 1 to this Attachment K. Consistent with the Transmission Provider's obligation under federal and state law, and under NERC and FRCC reliability standards, the Transmission Provider is ultimately responsible for the transmission plan.

4.3 The FRCC TWG sets the schedule for data submittal and frequency of information exchange which starts at the beginning of each calendar year. Updates and revisions are discussed at the FRCC PC meetings by the members. This process requires extensive coordination and information exchange over a period of several months as the FRCC develops electric power system load-flow databank models for the FRCC Region. The models include data for every utility in peninsular Florida and are developed and maintained by the FRCC. The TWG is responsible for developing and maintaining power flow base cases. The FRCC power flow base case models contain the data used by the FRCC and transmission providers for intra- and inter-regional assessment studies, and other system studies. The models created also are the basis for the FRCC submittal to the NERC Multi-regional Modeling Working Group ("MMWG"). TWG members support the data collection requirements and guidelines related to the accurate modeling of generation, transmission and load in the power flow cases. The data collected includes:

For power flow models:

- Bus data; (name, base voltage, type, area assignment, zone assignment, owner)
- Load data; (bus, MW, MVAR, area assignment, zone assignment, owner)
- Generator data; (bus, machine number, MW, MVAR, status, PMAX, PMIN, QMAX, QMIN, MVA base, voltage set-point, regulating bus)
- Branch data; (from bus, to bus, circuit number, impedances, ratings, status, length, owner)
- Transformer data; (from bus, to bus, to bus, circuit number, status, winding impedances, ratings, taps, voltage control bus, voltage limits, owner)
- Area interchange data; (area, slack bus, desired interchange, tolerance)
- Switched shunt data
- Facts device data

For dynamic stability models (in addition to power flow model data):

- Generator models; (turbine, generator, governor, exciter, power system stabilizers)
- Relay models; (distance, out of step, underfrequency)
- Special protection scheme models

For short circuit models (in addition to power flow model data):

- Zero and negative sequence impedances;

The databank models are compiled and incorporate load projections by substations, firm transmission services, and transmission expansion projects over the 10 year planning horizon. Transmission Provider utilizes the FRCC databanks which contain projected loads as well as all planned and committed transmission and generation projects, including upgrades, new facilities and changes to planned in-service dates over the planning horizon, as the base case for Transmission Provider's studies. These databanks are maintained by the FRCC Transmission Working Group and are updated on a periodic basis to ensure that the assumptions are current. Transmission Provider makes available to a transmission service customer the underlying data, assumptions, criteria and transmission plans utilized in the study process. If information is deemed confidential, Transmission Provider requires the customer to enter into a confidentiality agreement prior to providing the confidential information.

4.4 The FRCC maintains databanks of all FRCC members' projected loads and planned and committed transmission and generation projects, including upgrades, new facilities, and changes to planned in-service dates. These databanks are updated on a periodic basis. The FRCC maintains and updates the load flow, short circuit, and stability models. All of this above information is distributed by the FRCC, along with the FRCC transmission planning studies, subject to possible redaction of user sensitive or critical infrastructure information consistent with market and business rules and standards.

4.5 Any transmission developer that is not participating in the regional transmission planning process (and therefore not seeking regulated cost-of-service recovery) that proposes to develop a transmission project in the FRCC region shall provide to the FRCC PC and affected transmission providers in the FRCC region such information and data related to its proposed project that are necessary to allow the FRCC PC and affected transmission providers in the FRCC region to assess the potential reliability and operational impacts of the non-participant developer's proposed transmission facility on the transmission system in the region. That information should include: transmission project timing, scope, network terminations, load flow data, stability data, HVDC data (as applicable), and other technical data necessary to assess potential impacts.

The required information and data shall be provided with the transmission developer's interconnection request(s). Non-participant developers' transmission projects will not be included in long-term planning models or interconnected to the existing transmission system until and unless: 1) interconnection service has been requested of affected transmission provider(s); and 2) all interconnection studies have been completed.

Section 5 Comparability

5.1 This comparability principle is applied in all aspects of the transmission planning process including each of the respective principles in this Attachment K. Transmission Provider incorporates into its transmission plans on a comparable basis all firm transmission obligations, both retail and wholesale. The retail obligations consist of load growth, interconnection and integration of new network resources, firm power purchases and new distribution substations. Transmission Provider wholesale obligations are existing firm wholesale power sales, existing long-term firm transmission service including firm point-to-point and network (interconnection and integration of network resources), projected network load, generator interconnections, and new delivery points.

5.2 Transmission Provider plans for forecasted load, generation additions/upgrades which include network resources and new distribution substations associated with retail service obligations. A network transmission customer provides corresponding data as part of the provision of service, such as load forecast data, generation additions/upgrades including network resource forecast, new delivery points, and other information needed by the Transmission Provider to plan for the needs of the customer. Both Transmission Provider and the transmission customers reflect their demand response resources within the information that is input within this planning process. The data required for planning the transmission system for both retail and wholesale customers is comparable. Transmission customers/users (retail and wholesale) accurately reflect their demand response resources appropriately in their load forecast projections. To the extent a customer/stakeholder has a demand response resource or a generation resource that is not incorporated into its submitted plans and such customer/stakeholder desires the Transmission Provider to specifically consider on a comparable basis such demand response resource or generation resource as an alternative to transmission expansion, or in conjunction with the Transmission Provider's transmission expansion plan, such customer/stakeholder sponsoring such demand response resource or generation resource shall provide the necessary information (cost, performance, lead time to install, etc.) in order for the Transmission Provider to consider such demand response resource or generation resource alternatives comparably with other alternatives. Any customer/stakeholder sponsoring a demand response resource or generation alternative should participate in the planning process. The Transmission Provider shall treat customer/stakeholder resources and its own resources on a comparable basis for transmission planning purposes. This comparability principle is also further described under the Local Transmission Planning Process as set forth in Appendix 1 to this Attachment K. The data/information is also provided to the FRCC for its use in databank development and analysis under the *FRCC Regional Transmission Planning Process*. These data requirements are generally communicated by OASIS, email, letter or combination thereof.

5.3 Transmission providers/owners submit to the FRCC their latest 10-year expansion plans for their transmission systems, which incorporate the transmission expansion needed to meet the transmission customer requirements, including a list of transmission projects that provides for all of the firm obligations based on the best available information. The FRCC compiles and distributes a list of projects distributed from the transmission providers/owners and updates the project status to keep the list current. FRCC compiles and distributes the transmission providers/owners' 10-year expansion plans. All transmission users and other affected parties are asked to submit to the FRCC any issues or special needs that they believe are not adequately addressed in the expansion plans.

5.4 Transmission providers that own or control or have been approved to own or control transmission facilities in the FRCC region may enroll in the FRCC regional planning process. These transmission providers must satisfy one of two enrollment criteria: (1) registered with NERC as a Transmission Service Provider or a Transmission Owner within the FRCC region; or (2) selected to develop a CEERTS project. Should a NERC-registered Transmission Service Provider or a Transmission Owner that owns or provides transmission service over facilities located adjacent to, and interconnected with, transmission facilities within the FRCC region provide an application to enroll in the FRCC regional planning process, such a request to expand the FRCC regional planning region will be considered by the FRCC. An entity may request enrollment in the planning process for purposes of regional cost allocation by submitting a written or email communication by authorized representative to the FRCC identifying that it is seeking to enroll. The FRCC will validate the request against the above criteria, provide a response back to the entity making the request in seven business days, and if the request is granted, which granting makes the enrollment effective, the FRCC will request that the Transmission Provider make the necessary OATT change to add the entity to the below list of enrolled transmission providers with a requested effective date of the date that the request was granted. Transmission providers that do not enroll in the regional planning process will not be obligated to pay the costs of transmission facilities that would otherwise be allocable to them under Order No. 1000, nor will their projects be eligible for Order No. 1000 cost allocation. If a developer that has been selected to develop a CEERTS project and is not also a Transmission Service Provider or Transmission Owner within the FRCC region abandons such project and that developer does not have any other approved CEERTS project, the FRCC will notify the developer that steps will be taken to remove it from the current list of enrolled transmission providers. Below is the current list of enrolled transmission providers:

Duke Energy Florida, Inc.

Florida Power & Light Company

JEA

Orlando Utilities Commission

Tampa Electric Company

Florida Municipal Power Agency

Seminole Electric Cooperative, Inc.

City of Tallahassee, Florida

5.5 A non-public utility transmission provider choosing to withdraw its enrollment in the FRCC regional planning process may do so by providing written notification of such intent to the Transmission Provider. A non-public utility's withdrawal shall be effective as of the date the notice of withdrawal is provided to the Transmission Provider. The withdrawing non-public utility will be subject to regional cost allocations, if any, that were approved in accordance with this Attachment K during the period in which it was enrolled and was determined to be a beneficiary. Any withdrawing non-public utility will not be allocated costs for regionally cost-allocated projects approved after its termination of enrollment becomes effective. Any withdrawing non-public utility will continue to be able to recover costs allocated to the beneficiaries of CEERTS projects that were allocated pursuant to this tariff until it has recovered such costs.

5.6 If a non-public utility transmission provider withdraws, the Transmission Provider shall submit to FERC an update to the list of enrolled transmission providers with a proposed effective date for the relevant tariff record that reflects the effective date of the withdrawal.

Section 6 Dispute Resolution

6.1 If a dispute arises between a transmission customer and the Transmission Provider under the local transmission planning process set forth in Appendix 1 to this Attachment K or involving Transmission Service under the Tariff, the senior representatives of the Transmission Provider and the customer shall attempt to resolve the dispute and may mutually agree to utilize a mediation service for that purpose. However, if such dispute is not resolved, then the Dispute Resolution Procedures set forth in Article 12 of the Tariff shall govern. If a dispute arises under this Attachment K involving the *FRCC Regional Transmission Planning Process* and/or cost allocation thereunder, then the Dispute Resolution Procedures set forth in Appendix 5 shall govern resolution of the dispute and the FRCC will notify the FPSC of any such dispute.

Section 7 Regional Participation

7.1 The *FRCC Regional Transmission Planning Process* begins with the consolidation of the long term transmission plans of all of the transmission providers/owners in the FRCC Region. Such transmission plans incorporate the integration of new firm resources as well as other firm commitments. Any generating or transmission entity not required to submit a 10 year plan to the FPSC submits its 10 year expansion plan to the FRCC, together with any issues or special needs they believe are not adequately addressed by the transmission providers/owners' 10 year plans. The FRCC process requires that the FRCC PC address any issue or area of concern not previously or adequately addressed with emphasis on constructing a more robust regional transmission system.

7.2 Each transmission provider/owner furnishes the FRCC with a study schedule for each system impact study so that other potentially affected transmission providers/owners can independently assess whether they may be affected by the request, and elect to participate in or monitor the study process. If a transmission provider/owner believes that it may be affected, it may participate in the study process.

7.3 FRCC has a reliability coordination arrangement with Southern Company Services, Inc. ("Southern"), which is located in the Southeastern Subregion of SERC Reliability Corporation ("SERC"). The purpose of the reliability coordination arrangement is to safeguard and augment the reliability on an inter-regional basis for Southern and the FRCC bulk power supply systems. This arrangement provides for exchanges of information and system data between Southern and the FRCC for the coordination of planning and operations in the interest of reliability. The arrangement also provides the mechanism for inter-regional joint studies and recommendations designed to improve the reliability of the interconnected bulk power system. The arrangement contributes to the safeguarding and augmenting of reliability through: (1) coordination of generation and transmission system planning, construction, operating, and protection to maintain maximum reliability; (2) coordination of interconnection lines and facilities for full implementation of mutual assistance in emergencies; (3) initiation of joint studies and investigations pertaining to the reliability of bulk power supply facilities; (4) coordination of maintenance schedules of generating units and transmission lines; (5) determination of requirements for necessary communication between the parties; (6) coordination of load relief measures and restoration procedures; (7) coordination of spinning reserve requirements; (8) coordination of voltage levels and reactive power supply; (9) other matters relating to the reliability of bulk power supply required to meet customer service requirements; and (10) exchange of necessary information, such as magnitude and characteristics of actual and forecasted loads, capability of generating facilities, programs of capacity additions, capability of bulk power interchange facilities, plant and system emergencies, unit outages, and line outages.

7.4 Southern Companies, Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "LG&E/KU"), Ohio Valley Electric Corporation ("OVEC"), Associated Electric Cooperative Inc., PowerSouth Energy Cooperative, Dalton Utilities, Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, South Mississippi Electric Power Association, Duke Energy Carolinas, and Duke Energy Progress sponsor the Southeastern Regional Transmission Planning ("SERTP") forum. The FRCC and the SERTP have established their respective links to transmission providers and FRCC/SERTP websites as applicable that contain study methodologies, joint transmission studies, and inter-regional transmission service and generator interconnection service related studies. The FRCC website link that contains this type of information can be found under the *Florida-SERC Inter-Regional Transmission Information* folder. In this folder please refer to a document entitled *FRCC Inter-regional Coordination Process* that describes how information, modeling data and expansion plans are shared. The SERTP website link is http://www.southeasternrtp.com. FRCC and SERTP transmission providers plan to attend transmission planning forums when study findings are presented to stakeholders that impact their respective transmission systems.

7.5 The FRCC is a member of the Eastern Interconnection Reliability Assessment Group ("ERAG") which includes other Eastern Interconnection reliability regional entities, the Midwest Reliability Organization, the Northeast Power Coordinating Council, Inc., Reliability First Corporation, SERC Reliability Corporation, and Southwest Power Pool. The purpose of ERAG is to ensure reliability of the interconnected system and the adequacy of infrastructure in their respective regions for the benefit of all end-users of electricity and all entities engaged in providing electric services in the region.

Section 8 Economic Planning Studies

8.1 In the performance of an economic sensitivity study that is identified as part of the *FRCC Regional Transmission Planning Process*, Transmission Provider plans to participate in such study utilizing the procedures that are contained in the *FRCC Regional Transmission Planning Process*. If Transmission Provider receives a specific request to perform economic studies for a transmission customer, Transmission Provider plans to utilize the OASIS for such requests. To the extent an economic study would involve other transmission providers/owners, Transmission Provider will coordinate with these providers/owners in performing the study. Stakeholders will collectively be allowed to request the performance of up to five (5) economic planning studies annually, at no charge to the individual requesting customer(s). The cost of the sixth and subsequent economic planning studies requested in a calendar year shall be assessed to the individual customer(s) requesting such studies. If there are similar interests for certain economic studies, stakeholders can coordinate with each other and the Transmission Provider during the transmission planning process to collectively select the five no-charge economic studies. If more than five economic planning studies are requested and the stakeholders are unable to agree on the selection of the five no-charge economic planning studies, then the Transmission Provider will select the five no-charge economic planning studies by selecting one study per stakeholder based on the time the economic planning study was submitted on OASIS (up to a maximum of five stakeholders) and continuing this iterative process until the five no-cost economic planning studies have been selected. In the event the Transmission Provider receives more than one request for an economic planning study which the Transmission Provider determines: (i) will have overlapping time periods of study; (ii) may involve the same facilities; and (iii) can be reasonably performed on a clustered basis, then the Transmission Provider will, either at the request of transmission customer(s) requesting the studies or if the Transmission Provider deems it to be appropriate, offer to cluster two or more qualifying study requests which meet the aforementioned criteria for an economic planning study. Transmission customers agreeing to the clustering must also agree: (i) to remain in the cluster throughout the performance of the study; and (ii) to share equally in the cost of the study, to the extent that there are such costs (i.e., for economic planning study requests beyond the first five in any calendar year). The Transmission Provider will consider an economic planning cluster study under this section as a single study in the context of the number of studies done at no cost each year.

8.2 The *FRCC Regional Transmission Planning Process* includes both economic and congestion studies. One of the sensitivities may include evaluating the FRCC Region with various generation dispatches that test or stress the transmission system, including economic dispatch from all generation (firm and non-firm) in the region. Other sensitivities may include specific areas where a combination/cluster of generation and load serving capability involving various transmission providers/owners in the FRCC experiences or may experience significant and recurring transmission congestion on their transmission facilities. Members of the FRCC PC may also request specific economic analyses that would examine potential generation resource options, demand resource options, or other types of regional economic studies, and to the extent information is available, may request a study of the cost of congestion. The FRCC PC may consider clustering studies as appropriate. Economic analyses should reflect the upgrades to integrate necessary new generation resources and/or loads on an aggregate or regional (cluster) basis.

Section 9 Cost Allocation

Subsections 9.1 – 9.3 apply to cost allocation for third party impacts resulting from the FRCC regional planning process; subsection 9.4 applies to cost allocation for CEERTS projects. The cost allocation provisions contained in the section relate to cost allocation procedures for specific circumstances as described herein. All other transmission cost allocation not specifically described below is provided in accordance with OATT provisions for generation interconnection and for network and point-to-point transmission service.

9.1 If a transmission expansion is identified as needed under the *FRCC Regional Transmission Planning Process* and such transmission expansion results in a material adverse system impact upon a third party transmission owner, the third party transmission owner may choose to utilize the FRCC Principles for Sharing of Certain Transmission Expansion Costs as outlined below in this Attachment K. The FPSC is involved in this process and provides oversight, guidance and may exercise its statutory authority as appropriate. A more detailed description of the FRCC Principles for Sharing of Certain Transmission Expansion Costs can be found on the FRCC website.

9.2 The FRCC Principles for Sharing of Certain Transmission Expansion Costs: (i) sets forth certain principles regarding the provision of financial funding to Transmission Owners (note: for this purpose, "Transmission Owner" means an electric utility owning transmission facilities in the FRCC Region) that undertake remedial upgrades to, or expansions of, their systems resulting from upgrades, expansions, or provisions of services on the systems of *other* Transmission Owners, and (ii) procedures for attempting to resolve disputes among Transmission Owners and other parties regarding the application of such principles. These principles shall not apply to transmission upgrades or expansions if, and to the extent that, the costs thereof are subject to recovery by a Transmission Owner pursuant to FERC Order No. 2003 or Order No. 2006.

9.3 Principles

9.3.1 Except for a CEERTS project for which it is not the project developer, each Transmission Owner in the FRCC Region shall be responsible for upgrading or expanding its transmission system in accordance with the *FRCC Regional Transmission Planning Process* consistent with applicable NERC and FRCC Reliability Standards and shall participate, directly or indirectly (as the member of a participating Transmission Owner, e.g., Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency), in the *FRCC Regional Transmission Planning Process* in planning all upgrades and expansions to its system.

9.3.2 If, and to the extent that, the need for a 230 kV or above upgrade to, or expansion of, the transmission system of one Transmission Owner (the "Affected Transmission Owner") is reasonably expected to result from, upgrade(s) or expansion(s) to, or new provisions of service on, the system(s) of another Transmission Owner or Transmission Owners (hereinafter "Precipitating Events"), and if such need is reasonably expected to arise within the FRCC planning horizon, the Affected Transmission Owner shall be entitled to receive

Financial Assistance (as defined herein) from each other such Transmission Owner and other parties, to the extent consistent with the other provisions hereof. Such upgrade or expansion to the Affected Transmission Owner's system shall hereinafter be referred to as the "Remedial Upgrade." Upgrade(s), expansion(s), or provisions of service on another Transmission Owner's system that may result in the need for a Remedial Upgrade on the Affected Transmission Owner's system for which Financial Assistance is to be provided hereunder include the following Precipitating Events:

- A new generating unit(s) to serve incremental load

- A new or increased long-term sale(s)/purchase(s) to or by others (different uses)

- A new or modified long-term designation of Network Resource(s)

- A new or increased long-term, firm reservation for point-to-point transmission service

Specific non-Precipitating Events are as follows: 1) Transmission requests that have already been confirmed prior to adoption of these principles; 2) Qualifying rollover agreements that are subsequently rolled over; 3) Redirected transmission service for sources to the extent the redirected service does not meet the Threshold Criteria described in subsection 9.3.5.A. Existing flows would not be considered "incremental."; and 4) Repowered generation if the MW output of the facility is not increased, regardless of whether the repowered unit is used more/less hours of the year.

9.3.3 Except for a CEERTS project for which it is not the project developer and except to the extent that an Affected Transmission Owner is entitled to Financial Assistance from other parties as provided herein, each Transmission Owner shall be responsible for all costs of upgrades to, and expansions of, its transmission system; provided, however, that nothing herein is intended to affect the right of any Transmission Owner or another party from obtaining remuneration from other parties to the extent allowed by contract or otherwise pursuant to applicable law or regulation (including, for example, through rates to a Transmission Owner's customers).

9.3.4 Except for a CEERTS project for which it is not the project developer, each Transmission Owner shall be solely responsible for the execution, or acquisition, of all engineering, permitting, rights-of-way, materials, and equipment, and for the construction of facilities comprising upgrades or expansions, including Remedial Upgrades, of its transmission system; provided, however, that nothing herein is intended to preclude a Transmission Owner from seeking to require another party to undertake some or all of such responsibilities to the extent allowed by contract or otherwise pursuant to applicable law.

9.3.5 Threshold Criteria: The following criteria ("Threshold Criteria") must be satisfied in order for an Affected Transmission Owner to be entitled to receive Financial Assistance from another party or parties in connection with a Remedial Upgrade:

A. A change in power flow of at least a 5% or 25 MW, whichever is greater, on the Affected Transmission Owner's facilities which results in a NERC or FRCC Reliability Standards violation;

B. The Transmission Expansion must be 230 kV or higher voltage; and

C. The costs associated with the Transmission Expansion must exceed $3.5 million.

9.3.6 In order for a Transmission Owner to be entitled to receive Financial Assistance from another party or parties hereunder in connection with a particular Remedial Upgrade, that Transmission Owner must: (i) participate, directly or indirectly, in the *FRCC Regional Transmission Planning Process*, and (ii) identify itself as an Affected Transmission Owner and identify the subject Remedial Upgrade in a timely manner once it learns of the need for that Remedial Upgrade.

9.3.7 The following principles govern the nature and amount of Financial Assistance that an Affected Transmission Owner is entitled to receive from one or more other parties with respect to a Remedial Upgrade:

A. A recognition of the reasonably determined benefits that result from the Remedial Upgrades due to the elimination or deferral of otherwise planned transmission upgrades or expansions.

B. Remedial Upgrade costs, net of recognized benefits, shall be allocated fifty-fifty, respectively, based on:

- The sources or cluster of sources which are causing the need for the transmission expansion; and
- The load in the area or zone associated with the need for the Transmission Expansion. (For these purposes, network customer loads embedded within a transmission provider's service area in the Transmission Zone would not be separately allocated any costs as such loads would be paying their load ratio share of the affected transmission provider's costs.)

C. Initially, there are six zones in the FRCC region. A request by a party to modify one or more zones should be substantiated on its merits (e.g., technical analysis, area of limited transmission capability). Below are principles that will guide how the boundaries of zones are determined:

- Electrically, a substantial amount of the generation within a zone is used to serve load also within that zone.

- Transmission facilities in a zone are substantially electrically independent of other zones.

- Zones represent electrical demarcation areas in the FRCC transmission grid that can be supported from a technical perspective.

D. The Financial Assistance provided to an Affected Transmission Owner related to one or more transmission service requests keyed to new sources of power is subject to repayment without interest over a ten year period through credits for transmission service charges by the funding party and at the end of ten years through payment of any outstanding balance.

9.3.8 Implementation and Dispute Resolution Process:

A. As soon as practical after a Transmission Owner shall have identified itself as an Affected Transmission Owner because of the need for a Remedial Upgrade, that Transmission Owner and parties whose actions shall have contributed, or are reasonably expected to contribute, to the need for that Remedial Upgrade which may be responsible for providing Financial Assistance in connection therewith in accordance herewith shall enter into good faith negotiations to: (i) confirm the need and cause for the Remedial Upgrade and their respective responsibilities for providing Financial Assistance to the Affected Transmission Owner, and (ii) establish a fair and reasonable schedule and means by which such Financial Assistance is to be provided to the Affected Transmission Owner.

B. In the event the parties identified in the foregoing subsection are unable to reach agreement on the determination or assignment of cost responsibility within a sixty (60) day period, the dispute shall be resolved pursuant to the Dispute Resolution Procedures in Appendix 5.

C. Nothing in this document is intended to abrogate or mitigate any rights a party may have before any regulatory or other body having jurisdiction.

D. During those circumstances in which this section 9.3.8 pertaining to Dispute Resolution Process is being utilized due to parties being unable to reach agreement on the determination or assignment of cost responsibility associated with a Remedial Upgrade(s), the parties shall continue in parallel with the Dispute Resolution Process with the engineering, permitting and siting associated with the Remedial Upgrade(s). *The fact that a matter is subject to Dispute Resolution hereunder shall not be a basis for any party being relieved of its obligations under this document.*

9.4 Cost Allocation for CEERTS Projects

9.4.1 There are three potential sets of CEERTS project costs that will be allocated: developer costs, related local project costs, and displacement costs. The general principle is to allocate all of the prudently-incurred costs of a CEERTS project to the entities that benefit from the project in proportion to the benefits received, although a CEERTS project developer may accept a cost cap for the developer costs, in which case the developer's costs up to the cost cap will be allocated. Cost allocations are determined in terms of percentages, with each beneficiary allocated a percentage of the CEERTS project costs. Entities that receive no benefit from a CEERTS project will not be allocated any project costs.

9.4.2 Project beneficiaries for a CEERTS project will be transmission providers within the FRCC region enrolled in the regional planning process (on behalf of their retail and wholesale customers) which will benefit from the project.

9.4.3 The cost allocation for CEERTS reliability/economic projects is based on the following formula using terms defined in section 1.2.9.C: ((TP Estimated Avoided Project Cost Benefit + TP Estimated Alternative Project Cost Benefit + TP Estimated Transmission Line Loss Value Benefit) / (Total Estimated Avoided Project Cost Benefit + Total Estimated Alternative Project Cost Benefit + Total Estimated Transmission Line Loss Value Benefit)) * Estimated CEERTS Project Cost. The cost allocation dollar amounts calculated here using estimated cost information will further be translated to a percentage for each beneficiary as a ratio of their allocated share of the total estimated cost of the CEERTS project. These percentages will be used to allocate actual CEERTS project costs that are recoverable pursuant to the applicable subsection of section 9.4.5. Examples of CEERTS project cost allocation are provided in Appendix 4, Examples 1 and 2.

9.4.4 The costs for CEERTS public policy projects that are identified through the process described in section 11 will be allocated to the enrolled transmission providers whose transmission systems provide access to the public policy resources. The cost allocation for each enrolled transmission provider will be as follows:

- Individual enrolled transmission provider MWs = number of megawatts of public policy resources enabled by the public policy project for the customers (including Native Load) within their transmission service territory.

- Total MWs = total number of megawatts of public policy resources enabled by the public policy project.

- Individual enrolled transmission provider cost allocation percentage = (Individual enrolled transmission provider MWs/Total MWs).

An example of the CEERTS public policy cost allocation is provided in Appendix 4, Example 3. These percentages will be used to allocate actual CEERTS project costs that are recoverable pursuant to the applicable subsection of section 9.4.5.

The process to interconnect individual generation resources is provided for under the generator interconnection section of each utility's OATT and not under this process.

Requests for transmission service that originate in a utility's system and terminate at the border shall be handled through that utility's OATT.

9.4.5 Transmission Project Funding and Rate Base/Cost Recovery:

A. If incumbent enrolled transmission providers are the only transmission developers for a particular project, then they shall have two options in the initial transmission project funding and subsequent cost recovery of developer costs. Note that if an incumbent enrolled transmission provider develops a CEERTS project and is not FERC-jurisdictional, it will make any requisite FERC filings through the declaratory order process used for non-jurisdictional enrolled transmission providers rather than under FPA section 205:

(1) Incumbent enrolled transmission providers may fund the transmission project in proportion to their cost responsibility for the project. For the portions of the projects that each of the companies were building that are related to their cost responsibility, the companies would include those transmission costs as identified in a Contribution in Aid to Construction (CIAC) filing at FERC within their respective rate bases and transmission revenue requirements. The costs would be reflected in FERC filed OATT rates in Account 107, Construction Work in Progress. When the assets go into service, the balance will be moved to Account 101, Electric Plant in Service and the Units of Property will be unitized to the FERC Accounts corresponding to the Units of Property. This treatment is for accounting purposes: a FERC filing and FERC approval would still be required to include Construction Work in Progress in rates. For the portion of the funding that was being provided for the transmission to be built by someone other than the incumbent, the payments by the incumbent (for their cost responsibility) would be recorded in Account 303, Miscellaneous Intangible Plant and amortized by debiting Account 404, Amortization of Limited-Term Electric Plant, and crediting Account 111, Accumulated Provision for Amortization of Electric Utility Plant. The amortization of the investment would be derived using a composite factor based on the most recently approved depreciation rates for the constructing company. The calculation of the composite factor would be based on the Units of Property installed in the transmission project. The amortization will begin when the project is declared in service. The costs and amortization would be reflected in FERC filed OATT rates until the

investment is fully amortized to expense. The company receiving the money would treat these monies as a CIAC and thus have no associated net book investment in its transmission rate base. CIAC agreements will be filed with FERC prior to any CIAC payments being made to the constructing developer. Enrolled transmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC for authorization to include the intangible asset investment and amortization expense in the formula rate. Traditional cost-based ratemaking procedures would be used to determine the impact of including the intangible asset investment in rate base and the amortization expense in operating expenses in deriving OATT rates. CIAC agreements filed with FERC would include workpapers to support the costs included in the determination of revenue requirements. See Example 1 provided in Appendix 6 for more detail and accounting treatment.

(2) Incumbent enrolled transmission providers may fund the portion of the transmission project that their company would be building/developing. Incumbent enrolled transmission providers would include the total transmission project costs that they are funding within their respective rate bases and transmission revenue requirements for recovery in their routine rate processes. For those portions of the project costs that are over and above their cost responsibility, the incumbent enrolled transmission providers would file with FERC for authorization to recover their Transmission Revenue Requirement ("TRR") associated with those project costs to be directly assigned to the beneficiary(ies) responsible for that portion of the cost assignment. The TRR when received by the incumbent developer would be treated as a revenue credit recorded in Account 456, Miscellaneous Revenue in its cost of service to offset the inclusion of other beneficiary(ies) assigned cost in rate base and revenue requirement. In addition to including the TRR for those portions of the project costs that were over and above their cost responsibility, the incumbent enrolled transmission providers would also include any TRR costs allocated to them in their FERC-filed cost of service in support of FERC-approved OATT rates. Enrolled transmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC for authorization to include their allocated TRR costs in the formula rate. See Example 2 provided in Appendix 6 for more detail and accounting treatment.

B. If a non-incumbent developer builds the CEERTS project, it shall file with FERC for authorization to recover its developer costs in the form of a TRR from the incumbent enrolled transmission providers in accordance with their cost responsibilities as determined by the cost allocation methodologies. The incumbent enrolled transmission providers may include those costs allocated to them in their respective wholesale rates (*e.g.*, in FERC-filed cost of service in support of FERC approved OATT rates). Enrolled transmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC to include their allocated TRR costs in the formula rate. See Example 3 provided in Appendix 6 for more detail and accounting treatment.

C. Incumbent enrolled transmission providers with formula-based OATT rates shall be allowed to revise their formula rates to include the intangible asset investment balance as directly assignable transmission function rate base, and amortization expense should be included as transmission function specific expense. Formula-based OATT rates shall be revised by submitting a separate FPA section 205 filing with FERC.

D. Enrolled transmission provider(s) will be responsible for recovering their related local project costs from the beneficiaries allocated such costs through a FPA section 205 filing if the enrolled transmission provider is FERC-jurisdictional or through FERC's declaratory order process if the enrolled transmission provider is non-jurisdictional.

E. Enrolled transmission provider(s) will be responsible for recovering their actual displacement costs, if applicable, through a FPA section 205 filing if the enrolled transmission provider is FERC-jurisdictional or through FERC's declaratory order process for non-jurisdictional enrolled transmission owners. In such filing, the enrolled transmission provider(s) will allocate displacement costs in the same manner as the CEERTS project costs are allocated.

9.4.6 Neighboring Transmission Planning Region Potential Cost Impacts Not Included in FRCC’s CEERTS Cost:

The costs associated with any required upgrades identified through the FRCC’s CEERTS project evaluation process identified in section 1.2.9.F for the neighboring transmission planning region will not be included in the CEERTS cost within the FRCC. However, nothing in this Attachment K prevents the beneficiaries or project sponsor of a CEERTS project that causes the need for upgrades in another region from voluntarily negotiating a resolution of the project impacts with the transmission owner(s) in the other region.

9.4.7 Allocation of Transmission Rights:

Enrolled transmission providers allocated costs of CEERTS projects shall have priority with regard to any transmission rights associated with such projects, in proportion to their respective share of such costs. Any use of the transmission rights allocated to the Transmission Provider, including use by the Transmission Provider itself, shall be governed by this Tariff.

Section 10 Recovery of Planning Costs

10.1 Planning study costs incurred by the Transmission Provider in the performance of studies requested by a customer/stakeholder associated with transmission service or generator interconnection service are separately addressed in this tariff under provisions that require the customer/stakeholder to pay the cost of such studies. Planning study costs incurred by the Transmission Provider in the performance of the first five economic planning studies will be absorbed by the Transmission Provider in its normal course of business of performing its obligations under this Attachment K. The cost of the sixth and additional economic planning studies in a calendar year will be assessed to the requesting entity as set forth in section 8.1. Other general transmission planning costs not associated with the above studies are routine cost-of-service items that would be reflected in both wholesale and retail transmission rates as appropriate.

Section 11 Public Policy Planning

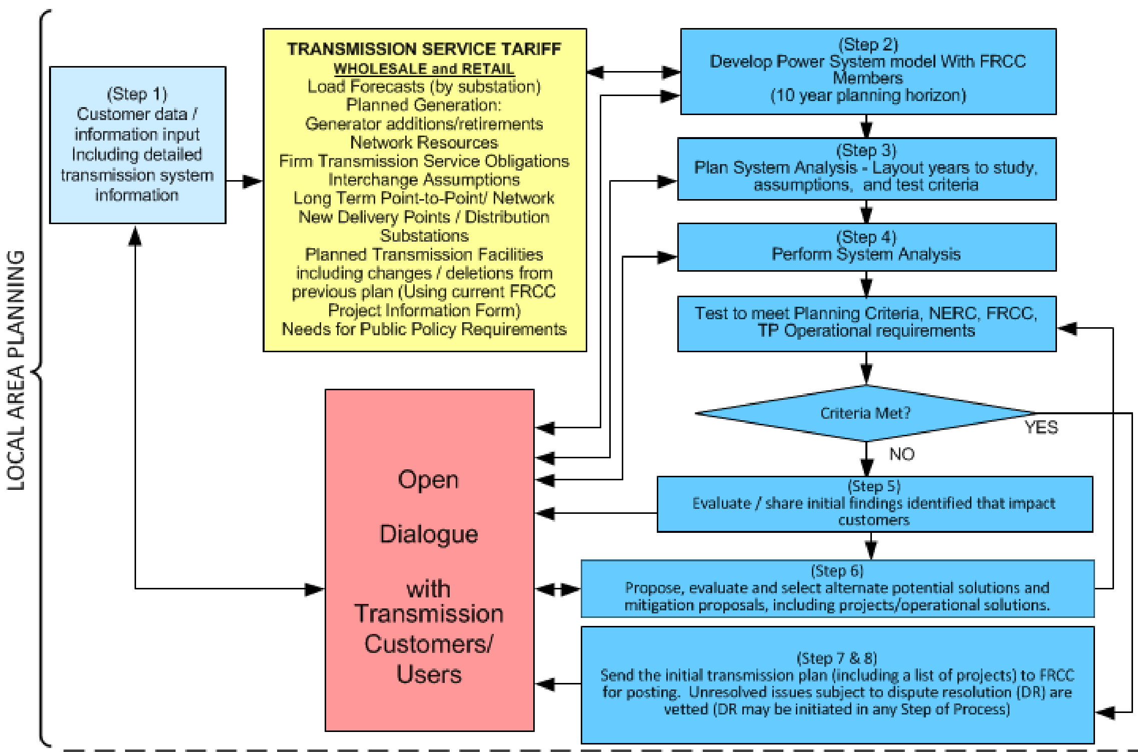
11.1 To be considered in transmission planning, a public policy requirement must be reflected in state, federal, or local law or regulation (including an order of a state, federal, or local agency). If a stakeholder identifies a transmission need that is driven by a public policy requirement, it must submit a written description of the need to the FRCC PC, prior to January 1st of the first year of the biennial regional projects planning cycle, for consideration in regional planning during that planning cycle. To the extent the information is available to the stakeholder, the description of the need should: 1) identify the state, federal, or local law or regulation that contains the public policy requirement; 2) identify the type of entity(ies) in the region to which the public policy requirement applies; 3) identify the subset of entities in the region subject to the public policy requirement that have a transmission need driven by the public policy requirement; 4) describe the type and nature of the transmission service, including the number of megawatts, needed from the enrolled transmission providers by such subset of entities to meet that transmission need. Any stakeholder submitting a potential public policy transmission need to the FRCC PC may, but is not required to, also propose a transmission project(s) to meet such a need along with its description of the need. All submissions will be posted on the FRCC website for public comment and will be reviewed to determine if a public policy requirement is driving a transmission need for which a solution is required. The FRCC PC, under the oversight of the FRCC Board, may seek, on a voluntary basis, additional information from entities identified as having potential needs and then will evaluate the submittals and any additional information to make a decision as to whether a public policy requirement is driving a transmission need for which a solution is required and will post this determination on the FRCC website prior to March 1st of the first year of the biennial regional projects planning cycle, along with an explanation and record of that determination (including a negative determination). If a public policy transmission need is identified for which a solution is required, CEERTS and local projects shall be proposed to address such a need.

Appendix 1 to Attachment K

Local Transmission Network Planning Process – Process Description

The Local Transmission Network Planning Process ("Local Process") is performed annually with the Transmission Provider's plan being finalized on or about April 1st of each calendar year. The times shown (in months) for each of the steps contained in the Local Process are target dates that recognize some potential overlapping of the various activities. The Transmission Provider may develop a different timeline where warranted with the concurrence of the Transmission Provider's Customers/Stakeholders. The timelines and dates in this Appendix 1 to Attachment K are to be used as guidelines subject to modification (modified or expedited) as warranted. It is also recognized and understood that under the Transmission Provider's OATT, there are certain FERC mandated timelines that are applied to Transmission Service Requests ("TSRs") and Generator Interconnection Service Requests ("GISRs") that may conflict and be of higher priority than the Local Process. Therefore, Transmission Provider's receipt of TSRs and/or GISRs may require the modification, from time to time, of the timelines described below.

TRANSMISSION PROVIDER's (TP) LOCAL TRANSMISSION NETWORK PLANNING PROCESS



Proceed to FRCC Regional Planning **Process)**

(Proceed to FRCC Regional Planning Process)

Local Transmission Network Planning Process – Process Description Overview:

- The Transmission Provider, which is ultimately responsible for the development of the Transmission Provider's annual 10 Year Expansion Plan, will lead the Local Process on a coordinated basis with the Customers/Stakeholders. This Local Transmission Planning Process will be implemented in such a manner as to ensure the development of the Local Transmission Plan in a timely manner. The Transmission Provider will facilitate each meeting throughout the process. The Transmission Provider will encourage an open dialogue and the sharing of information with Customers/Stakeholders (subject to confidentiality requirements and FERC Standards of Conduct – *note:* the provision for handling of information also applies to all steps of the Local Process) in the development of the Local Transmission Plan.

- Customers/Stakeholders are invited to participate in the Transmission Provider's Local Process.

- The Local Process will comply with the FERC nine principles as well as the provisions below.

- All annual initial kick-off meetings will be open to all Customers/Stakeholders and noticed by the Transmission Provider to all Customers/Stakeholders with sufficient time to arrange for travel planning and attendance (two week minimum). The annual initial kick-off meeting will be a face-to-face meeting; otherwise, with the consent of the Customers/Stakeholders, meetings may be organized as face-to-face meetings, conference calls, web-ex events, etc., wherein the dialogue and communications will be open, direct, detailed, and consistent with the FERC Standards of Conduct and confidentiality requirements.

- The Customers/Stakeholders may initiate the dispute resolution process at any point in the Local Process where agreement between the Transmission Provider and Customer(s)/Stakeholder(s) cannot be reached.

- The entities generally responsible for undertaking the tasks described below are designated as the TP (Transmission Provider) and/or the S (Customers/Stakeholders).

The study process will include the following steps:

A. Data Submission Requirements (STEP 1 – 3 months)

In order for The Transmission Provider to carry out its responsibility of developing the Transmission Provider's annual 10 Year Expansion Plan and leading the Local Process on a coordinated basis with the Customers/Stakeholders, data submission by the Customer/Stakeholder on a timely manner (on or before January 1st of each year) is essential. As such, the following data submission requirements from Customers/Stakeholders to the Transmission Provider are established. The Customers/Stakeholders will submit data to the Transmission Provider in a format that is compatible with the transmission planning tools in common use by the Transmission Provider. The Transmission Provider will identify the data format to be used by the Customers/Stakeholders for all data submissions, or absent a Transmission Provider identified data format, the Customers/Stakeholders will use their discretion in selection of data format. Examples of data that may be required are:

- Load forecasts, if appropriate:

    - Coincident and non-coincident Peak load forecasts will be provided for the subsequent 11 years, for each summer and winter peak season, with real power and reactive power values for each load serving substation (reflected to the transformer high-side) or delivery Point, as applicable.

- Transmission Delivery Points, if appropriate:

    - Delivery Point additions and/or Delivery Point modifications that have not previously been noticed to the Transmission Provider will be communicated by the Customer/Stakeholder to the Transmission Provider via the standard Delivery Point Request letter process.

    - Delivery Point additions and/or Delivery Point modifications that have not previously been included in the FRCC Databank Transmission Planning models will be provided by the Customers/Stakeholders to the Transmission Provider via the standard FRCC Project Information Sheet ("PIF") per the attached Transmission Provider provided form and by the Siemens PTI PSS/E IDEV file format, compatible with the Siemens PTI PSS/E version in common use throughout the FRCC Region at that time.

- Network Resource Forecast, if appropriate:

    - Network Resource forecasts will be provided for the subsequent 11 years, for each summer and winter peak season. At a minimum, the following data will be provided: 1. the name of each network resource; 2. the total capacity of each network resource; 3. the net capacity of each resource; 4. the designated network capacity of each resource; 5. the Balancing Authority Area wherein each network resource is interconnected to the transmission grid; 6. the transmission path utilized to deliver the capacity and energy of each network resource to the Transmission Provider's transmission system; 7. the Transmission Provider's point of receipt of each network resource; 8. the contract term of each network resource, if not an owned network resource; and 9. the dispatch order of the entire portfolio of network resources (subject to confidentiality requirements and Standards of Conduct).

- Needs driven by public policy requirements, if appropriate:

    - To be considered in the local transmission network planning process, a public policy requirement must be reflected in state, federal, or local law or regulation (including an order of a state, federal, or local agency). If a stakeholder identifies a transmission need that is driven by a public policy requirement, it must submit a written description of the need to the Transmission Provider, for consideration in local planning during that planning cycle. To the extent the information is available to the stakeholder, the description of the need should:

1) Identify the state, federal, or local law or regulation that contains the public policy requirement;

2) Identify the type of entity(ies) in the Transmission Provider's area to which the public policy requirement applies;

3) Identify the subset of entities in the area subject to the public policy requirement that have a transmission need driven by the public policy requirement;

4) Describe the type and nature of the transmission service needed from the transmission provider by such subset of entities to meet that transmission need.

- How, where, and to whom, the data will be submitted to:

  - If hardcopy, the Transmission Provider will provide the mailing address;
  - If faxed, the Transmission Provider will provide the fax number;
  - If e-mailed, the Transmission Provider will provide the e-mail address;
  - If delivered to a password protected FTP site or e-vault, the Transmission Provider will provide the folder for the data, the contact person to be notified of the data delivery, etc. consistent with confidentially requirements and FERC Standards of Conduct.

The Transmission Provider will provide the name and contact details for the Transmission Provider point of contact for data submittal questions.

B. Stakeholder Data Submissions (S) (STEP 1 – con't)

- On or before January 1^{st} of each calendar year, the Customers/Stakeholders will submit the required data (as directed by the Transmission Provider procedures communicated in A. above), plus any additional data that they believe is relevant to the process.

- On or before January 1^{st} of each calendar year, the Customers/Stakeholders will submit to the Transmission Provider the name(s) and contact details for those individuals that will represent them as the point(s) of contact for resolution of any data submittal or study questions/conflicts.

- On or before January 1st of each calendar year, the Customers/Stakeholders will submit the name(s) of those individuals that will represent them during the FRCC Data Bank Transmission Planning Model development process and throughout the Local Process. Name(s), contact details, and their FERC Standards of Conduct status (i.e., Reliability Only, Merchant function, etc.) will be provided. The contact individuals can be changed by the Customers/Stakeholders with notice to Transmission Provider.

- On or before January 1st of each calendar year, the Customers/Stakeholders will submit a written description of a transmission need that a Stakeholder believes is driven by a public policy requirement to the Transmission Provider. Any stakeholder submitting a potential public policy transmission need to the Transmission Provider may, but is not required to, also propose a transmission project(s) to meet such a need along with its description of the need.

  - All submissions will be posted on the Transmission Provider's website for public comment and will be reviewed to determine if a public policy requirement is driving a transmission need for which a solution is required.

  - The Transmission Provider may seek, on a voluntary basis, additional information from entities identified as having potential needs and then will evaluate the submittals and any additional information to make a decision as to whether a public policy requirement is driving a transmission need for which a solution is required and will post this determination on the Transmission Provider's website prior to April 1st of the local transmission network planning cycle, along with an explanation and record of that determination (including a negative determination). If a public policy transmission need is identified for which a solution is required local projects shall be proposed to address such a need.

C. FRCC Data Bank Transmission Planning Model Development Process (TP/S) (STEP 2 – 2 months)

- The FRCC Regional Data Bank Development Process will control the model development schedule and work product as established by the applicable FRCC Working Group.

D. Kick-off for Transmission Provider's Local Transmission Network Planning Process (STEP 2 – con't - 1 month)

- The Transmission Provider will, approximately two (2) weeks prior to the second quarter initial kick-off meeting (or other date, if Transmission Provider and Customers/Stakeholders agree), communicate via e-mail with all

Customers/Stakeholders the schedule/coordination details of the Transmission Provider's Local Process kick-off meeting(s). Customer/Stakeholder shall provide to Transmission Provider a confirmation of their intent to participate in the initial kick-off meeting at least three (3) days prior to such meeting. (TP)

- The Transmission Provider will, in advance of the Kick-off meeting(s), with sufficient time for Customer/Stakeholder review, provide to the Customers/Stakeholders a proposed study schedule, the NERC and FRCC Reliability Standards that will apply to the study, and/or guidelines that will apply to the study and Transmission Provider developed criteria that will apply to the study, including public policy requirements. (TP)

- The initial Kick-off meeting in the second quarter of the calendar year will begin the Transmission Provider's Local Process. The Transmission Provider will review and validate the input data assumptions received from each Customer/Stakeholder, discuss the proposed study schedule, and discuss the study requirements, which will include, but not be limited to, the following:

  - The methodologies that will be used to carry out the study (TP/S)

  - The specific software programs that will be utilized to perform the analysis (TP)

  - The Years to study (TP/S)

  - The load levels to be studied (e.g., peak, shoulder and light loads) (TP/S)

  - The criteria for determining transmission contingencies for the analysis (i.e. methods, areas, zones, voltages, generators, etc.) (TP/S)

  - The Individual company criteria (i.e., thermal, voltage, stability and short circuit) by which the study results will be measured (TP/S)

  - The NERC reliability standards by which the study results will be measured (TP/S)

  - The FRCC reliability standards and requirements by which the study results will be measured (TP/S)

  - Customer/Stakeholder proposed study scenarios for Transmission Provider consideration in the analysis (TP/S)

  - Potential solutions proposed by Stakeholders to identified transmission needs driven by public policy requirements (TP/S)

- The kick-off process will be complete when the schedule, standards, criteria, rules, tools, methods and Customer/Stakeholder participation are finalized for the study process to (described below) begin. (TP/S)

E. Case Development (TP) (STEP 3 – 1 month)

- Utilizing all of the data received from the Customers/Stakeholders during the data submission stage and the standards, criteria, rules, tools, and methods determined in the kick-off meeting(s), the Transmission Provider will develop the base case models to be used for the study. These models will be developed in the Siemens PTI PSS/E file format, compatible with the Siemens PTI PSS/E version in use by the Transmission Provider.

- Utilizing all of the data received from the Customers/Stakeholders during the data submission stage and the standards, criteria, rules, tools, and methods determine in the kick-off meeting, the Transmission Provider will develop the change case models to be used for the study. These models will be developed in the Siemens PTI PSS/E file format, compatible with the Siemens PTI PSS/E version in use by the Transmission Provider.

- The Transmission Provider will electronically post and provide notice to the Customers/Stakeholders of the posting of the base case models, the change case models and/or the IDEV files.

F. Perform System Analysis (STEP 4 - 1 to 2 months)

- The Transmission Provider will perform the study analyses (verification that thermal, voltage, stability and short circuit values meet all planning criteria) on the local transmission plan (including potential solutions to identified transmission needs driven by public policy requirements) and produce the initial unfiltered, un-processed input data, output data, and files. (TP).

- The Transmission Provider will electronically post and provide notice to the Customers/Stakeholders of the posting of the initial unfiltered, un-processed input data, output data, and files. (TP/S)

G. Assessment and Problem Identification (STEP 5 - 1 month)

- The Transmission Provider will evaluate at the local level the initial unfiltered, un-processed output data to identify any problems / issues for further investigation. The Transmission Provider will document, electronically post, and provide notice to the Customers/Stakeholders if there is an impact to them of the posting of the evaluation results documentation associated with the impact to the Customer/Stakeholder. (TP/S)

- The Customers/Stakeholders may perform their own additional sensitivities. (S)

H. Mitigation / Alternative Development (STEP 6 - 1 to 2 months)

- The Transmission Provider will identify potential solutions / mitigation proposals, including solutions to identified transmission needs driven by public policy requirements, to address problems / issues. (TP)

- The Transmission Provider will document, electronically post, and provide notice to the Customers/Stakeholders of the posting of the identified potential solutions / mitigation proposals to address problems / issues related to the impacted Customer(s)/Stakeholder(s).

- The Customers/Stakeholders may provide alternative potential solutions / mitigation proposals, including alternative solutions to identified transmission needs driven by public policy requirements, for the Transmission Provider to consider. Such information shall be provided in IDEV format and posted. (TP/S)

- The Transmission Provider will determine the effectiveness of the potential solutions through additional studies (thermal, voltage, stability and short circuit). The Transmission Provider may modify the potential solutions, as necessary, such that required study criteria are met. (TP)

- The Transmission Provider will identify feasibility, timing and cost-effectiveness of proposed solutions that meet the study criteria. (TP/S)

I. Selection of Preferred Transmission Plan (STEP 6 con't - 1 to 2 months)

- The Transmission Provider, in consultation with the Customers/Stakeholders, will compare the alternatives and select the preferred solution / mitigation alternatives based on feasibility, timing and cost effectiveness that provide a reliable and cost-effective transmission solution, taking into account neighboring transmission providers' transmission plans. (TP/S)

- In case of Transmission Provider and Customer/Stakeholder dispute, the dispute resolution process described in section 6.1 will be utilized. (TP/S)

J. Send Selected Local Transmission Network Plan Results (Transmission Provider's Ten Year Expansion Plan) to the FRCC (STEPS 7 & 8 - 1 to 2 months)

- The Transmission Provider will submit the Transmission Provider's proposed local transmission network plan results (the Transmission Provider's 10 Year Expansion Plan) to the FRCC for posting with other transmission plans as the FRCC's initial regional transmission expansion plan (reference the *Initial Plans* on the FRCC website), along with an indication whether there are any pending disagreements regarding the Plan (and if there are, will elicit from the dissenting entity(ies), and provide, a minority report regarding such differences of opinion). The Transmission Provider's 10 Year Expansion Plan will include all transmission system projects without differentiation between bulk transmission system projects and lower voltage transmission system projects (i.e. all projects 69 kV and above). This Transmission Provider submittal to the FRCC will be made on or about April 1 and will become part of the initial FRCC regional transmission plan. (TP)

- The *FRCC Regional Planning Process* will now start and the FRCC Regional Planning Process rules and guidelines will now control the transmission planning process. (TP/S)

- Following completion of the Transmission Provider's submission of the local transmission network plan results (the Transmission Provider's 10 Year Expansion Plan) to the FRCC, the Transmission Provider will, either directly or through the FRCC project status reporting process, make available to the Customers/Stakeholders project descriptions, project scheduled in-service dates, project status, etc. for all projects. This information should be updated no less often than quarterly. (TP)

Appendix 2 to Attachment K

FRCC Quorum and Voting Sectors

Note: The below descriptions of the FRCC's Quorum and Voting provisions were extracted from the FRCC *Rules of Procedure for FRCC Standing Committees.* The FRCC PC is one of the Standing Committees within the FRCC.

A. <u>Quorum</u>

Representation at any meeting of the standing committees of 60% or more of the total voting strength of the Standing Committee, shall constitute a quorum for the transaction of business at such meeting; provided, however, that action on matters dealing with the scope or funding of Member Services shall require sixty percent (60%) or more of the total voting strength of members of the Standing Committee representing Voting Members that are Services Members; and provided further that a quorum shall require that at least three (3) Sectors are represented, all three of which shall be Sectors, a majority of the members of which are Services Members in the case of a quorum for action on matters governing Member Services.

If a quorum is not present at any meeting of the standing committees, then no actions may be taken for the purpose of voting. The representatives present may decide to have discussions concerning agenda items as long as voting is not called.

B. <u>Voting</u>

Voting is by Sector. Each voting representative present at a meeting is assigned a vote equal to the voting strength of their Sector, as provided in this section, divided by the number of voting representatives present in that Sector, except that no voting representative present at a meeting shall have more than one (1) vote, except an Investor Owned Utility Sector voting representative who may have up to 1.167 votes. Action by the Standing Committee shall require an affirmative vote equal to or greater than sixty percent (60%) of the total voting strength of the Standing Committee.

Sector Votes

(1) Suppliers Sector	2.5 Votes
(2) Non-Investor Owned Utility Wholesale Sector	2 Votes
(3) Load Serving Entity Sector	
Municipal	0.5 Vote
Cooperative	0.5 Vote
(4) Generating Load Serving Entity Sector	3.0 Votes
(5) Investor Owned Utility Sector	3.5 Votes
(6) General	1 Vote
Total	13 Votes

Appendix 3 to Attachment K
Project Developer Qualification Criteria

1. Demonstration that the project developer is technically, and financially capable of (i) completing the CEERTS project in a timely and competent manner; and (ii) operating and maintaining the CEERTS facilities consistent with Good Utility Practice and applicable reliability criteria for the life of the project. To support this demonstration, the following information should be provided/shown:

   A. Project developer's current and expected capability to finance, or arrange financing for the transmission facilities:

      1. Evidence of its demonstrated experience financing or arranging financing for transmission facilities, including a description of such projects (not to exceed ten) over the previous ten years, the capital costs and financing structure of such projects, a description of any financing obtained for these projects through any approved rates, the financing closing date of such project, and whether any of the projects are in default;

      2. Its audited financial statements from the most recent three years and its most recent quarterly financial statement, or equivalent information;

      3. Current credit ratings from Moody's Investor Services and Standard & Poors, if available;

      4. A summary of any history of bankruptcy, dissolution, merger, or acquisition of the project developer or any predecessors in interest for the current calendar year and the five calendar years immediately preceding its submission of information related to affiliated entities;

      5. A summary of outstanding liens against the developer(s); and

      6. Such other evidence that demonstrates its current and expected capability to finance a CEERTS project.

      The project developer must identify the portions of this financial data that would need to be treated as confidential information in accordance with the FRCC confidentiality practices and subject to disclosure only to those that have signed a confidentiality agreement.

   B. Total dollar amount of CEERTS estimated project(s) cost up to which the project developer wants to be deemed qualified.

   C. A discussion of the project developer's business practices that demonstrate that its business practices are consistent with Good Utility Practices for proper licensing, designing, right-of-way acquisition, constructing, operating and maintaining transmission facilities that will become part of the regional transmission grid. The project developer shall also provide the following information for the current calendar year and the previous five calendar years:

1. A summary of any violations of law by the project developer found by federal or state courts, federal regulatory agencies, state public utility commissions, other regulatory agencies, or attorneys general; and

2. A summary of any instances in which the project developer is currently under investigation or is a defendant in a proceeding involving an attorney general or any state or federal regulatory agency, for violation of any laws, including regulatory requirements.

D. Technical and engineering qualifications and experience;

E. Past history of meeting transmission project schedules;

F. Past history regarding providing construction and maintenance of transmission facilities and/or contracting for the construction and maintenance of transmission facilities;

G. Capability to adhere to standardized construction, maintenance and operating practices;

H. Plans for compliance with all applicable reliability standards:

I. Planning standards that will be used to develop the project: and

J. Plans to obtain the appropriate NERC certifications.

2. An attestation from an officer of the project developer stating that the information that is being submitted is true and that the project developer will comply with the provisions identified in the qualification data submittal, and will submit a biennial (or more often if the information provided has materially changed) update of the information submitted, accompanied by an attestation from an officer of the project developer that the previously submitted information remains correct and has not materially changed since the last attestation, with such attestation to be submitted biennially while that transmission developer has a transmission project under consideration in the FRCC Regional Planning Process, under construction in the FRCC region or in-service within the FRCC region.

3. For joint ventures, partnerships, or other multiple-party developer arrangements, the qualification criteria above will be applied to the designated lead entity, which will be responsible for meeting the qualification criteria. Sharing of such responsibilities with other entities may be achieved contractually between the designated lead entity and its partners.

Appendix 4 to Attachment K
Examples of CEERTS Cost Allocation Methodology

Example 1: Reliability/Economic Project

- CEERTS project where Enrolled Transmission Providers A, B and C all receive benefits from the project.
- The project developer is a non-incumbent developer

Assumptions:

- Estimated CEERTS Project Cost = $401M:
  - Estimated Developer Cost = $400M
  - Total Estimated Related Local Project Costs = $1M
- Total Estimated Avoided Project Cost Benefit = $500M:
  - Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $300M
  - Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $200M
  - Enrolled Transmission Provider C Estimated Avoided Project Cost Benefit = $0
- Total Estimated Alternative Project Cost Benefit = $0M
- Total Estimated Transmission Line Loss Value Benefit = $14M:
  - Enrolled Transmission Provider A Estimated Transmission Line Loss Value Benefit = $4M
  - Enrolled Transmission Provider B Estimated Transmission Line Loss Value Benefit = $5M
  - Enrolled Transmission Provider C Estimated Transmission Line Loss Value Benefit = $5M

Benefit to Cost Ratio:

- ("Total Estimated Avoided Project Cost Benefit" ($500M) plus "Total Estimated Alternative Project Cost Benefit" ($0M) plus "Total Estimated Transmission Line Loss Value Benefit" ($14M)) divided by Estimated CEERTS Project Cost ($401M) = 1.28, therefore this CEERTS project passes the benefit to cost ratio threshold.

CEERTS Project Cost Allocation:

- (Percentages in example are rounded to nearest whole percentage)
  - Enrolled Transmission Provider A = ($300M + $4) ÷ $514M = 59%
  - Enrolled Transmission Provider B = ($200M + $5M) ÷ $514M) = 40%
  - Enrolled Transmission Provider C = ($0 + $5M) ÷ $514M) = 1%

Example 2: Reliability/Economic Project

- CEERTS project where Enrolled Transmission Providers A & B each receive avoided cost benefits from the project
- There are no transmission loss benefits
- The project developer is a non-incumbent developer

Assumptions:

- Estimated CEERTS Project Cost = $400 M:
  - Estimated Developer Cost = $400 M
- Total Estimated Avoided Project Cost Benefit = $300 M:
  - Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $100 M
  - Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $200 M
- Total Estimated Alternative Project Cost Benefit = $0M

Benefit to Cost Ratio:

- "Total Estimated Avoided Project Cost Benefit" ($300 M) divided by Estimated CEERTS Project Cost ($400 M) = 0.75, therefore this CEERTS project does not pass the benefit to cost ratio threshold.

CEERTS Project Cost Allocation:

- N/A

Example 3: Public Policy Project

- CEERTS project where LSEs within Enrolled Transmission Providers A, B and C each receive benefits from the project
- The project developer is a non-incumbent developer

Assumptions:

- Public policy CEERTS project enables access to a total of 600 MW of public policy resources
- Public policy CEERTS project enables LSEs within Enrolled Transmission Providers A, B and C to access the public policy resources:
  - Enrolled Transmission Provider A = 100 MWs
  - Enrolled Transmission Provider B = 200 MWs
  - Enrolled Transmission Provider C = 300 MWs

CEERTS Project Cost Allocation:

- Enrolled Transmission Provider A = (100 MW / 600 MW) = 17%
- Enrolled Transmission Provider B = (200 MW / 600 MW) = 33%
- Enrolled Transmission Provider C = (300 MW / 600 MW) = 50%

Example 4: Newly-Proposed CEERTS Project Displacing a Previously-Approved CEERTS Project

- Previously-approved CEERTS project was estimated to provide LSEs within Enrolled Transmission Provider A and B benefits
- Newly-proposed CEERTS project would displace the previously-approved CEERTS project as well as being estimated to provide LSEs within Enrolled Transmission C benefits from the newly-proposed CEERTS project
- The newly-proposed CEERTS project would displace the previously-approved CEERTS project

<u>Previously-Approved CEERTS Project:</u>

Assumptions:

- Estimated Previously-Approved CEERTS Project Cost = $75M
- Total Estimated Previously-Approved CEERTS Project Avoided Project Cost Benefit = $100M
  - Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $50M
  - Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $50M

Previously-Approved CEERTS Project Cost Allocation:

- (Percentages in example are rounded to nearest whole percentage)
  - Enrolled Transmission Provider A = ($50M / $100M) = 50%
  - Enrolled Transmission Provider B = ($50M / $100M) = 50%

<u>Previously-Approved CEERTS Project Displaced by a Newly-Proposed CEERTS Project:</u>

Assumptions:

- Estimated Newly-Proposed CEERTS Project = $100M
- Total Estimated Newly-Proposed CEERTS Avoided Project Cost Benefit = $125M
  - Total Estimated Previously-Approved CEERTS Project Cost Benefit = $75M
  - Enrolled Transmission Provider C Estimated Avoided Project Cost Benefit = $50M

Newly-Proposed CEERTS Project Cost Allocation:

- (Percentages in example are rounded to nearest whole percentage)
  - Previously-Approved CEERTS Project Enrolled Transmission Providers (A & B) = ($75M / $125) = 60%
    - This 60% of the cost responsibility would be allocated to Enrolled Transmission Providers A & B:
      - Enrolled Transmission Provider A = 60% * 50% = 30%
      - Enrolled Transmission Provider B = 60% * 50% = 30%
  - Enrolled Transmission Provider C = ($50M / $125M) = 40%

Appendix 5 to Attachment K

Dispute Resolution Procedures for Disputes Arising from the *FRCC Regional Transmission Planning Process* and/or Cost Allocation Thereunder

Section 1 Dispute Resolution.

These procedures are established for the equitable, efficient and expeditious resolution of disputes arising under this Attachment K from the *FRCC Regional Transmission Planning Process* and/or cost allocation thereunder. These procedures shall be used to resolve such disputes between FRCC Members, between an FRCC Member (hereafter "Member") and a consenting non-member, or between FRCC and any Member or consenting non-member (any of the foregoing being referred to hereinafter as a "party"), arising from an act or omission by FRCC, or from an act or omission by a party in its capacity as a Member. Among other things these procedures do not apply to disputes that are covered by the dispute resolution provisions of the FRCC Compliance Monitoring and Enforcement Program (Exhibit D to the Delegation Agreement between FRCC and NERC) or other NERC dispute resolution provisions, disputes subject to other dispute resolution procedures set forth in Members' Open Access Transmission Tariffs, and/or disputes arising under Appendix 1 of this Attachment K, and do not supersede, unless agreed to by the parties, any dispute resolution agreement between the parties applicable to a dispute .

These procedures supersede the dispute resolution provisions in the *FRCC Regional Transmission Planning Process*.

Multiple parties with the same or substantially similar interests may be joined in the same proceeding.

The parties are strongly encouraged to take part in the complete process described herein prior to initiation of judicial proceedings or the utilization of other external dispute resolution processes, but the use of any of the steps of the process shall not be a required condition for the initiation of judicial or regulatory proceedings or the utilization of other external dispute resolution processes, including the filing of a complaint pursuant to Section 206 of the Federal Power Act.

FRCC shall be involved in the administration of a proceeding as provided in section 5 to coordinate with the parties to facilitate the resolution of the dispute, and to provide personnel, coordination, and meeting and other facilities as specified herein.

Section 2 Initiation.

Any Member, consenting non-member or FRCC (the "Invoking Party") may initiate these dispute resolution procedures by making a request in writing to the FRCC President with a copy to all other parties to the dispute; provided, however, that if FRCC initiates the dispute, FRCC shall make a request in writing to the Chair of the FRCC Board of Directors, with a copy to the

FRCC Vice Chair and all other parties. The copy of the dispute resolution request for each party shall be sent to and accepted by the Member representative appointed in accordance with Section 1.7 of the FRCC Bylaws. The FRCC President will inform the FRCC Board of Directors of the initiation of any dispute resolution proceedings, and the docket number and title assigned to the dispute. The request must contain:

(a) a statement of the issues in dispute;

(b) the position of the party on each of the issues;

(c) the relief sought by the party;

(d) an explanation of the asserted right to such relief under an applicable tariff, contract or other legal standard or obligation;

(e) the dispute resolution step under Section 4 at which the party proposes to begin; and

(f) any proposed modifications or specific additions to the proceedings described in this Dispute Resolution Procedure by which the dispute may be resolved.

Each person or entity identified as party to the dispute (a "Noticed Party") shall submit a response to the request to the FRCC President, the FRCC Chair and FRCC Vice Chair, and each other party to the dispute (the "Dispute Response"). Each response shall set forth the position of the party on each of the points identified above. A party shall have 20 business days from its receipt of the request to submit its Dispute Response.

Section 3 Dispute Resolution Process.

The dispute resolution process described herein shall be conducted and administered in accordance with the FRCC Bylaws and such other FRCC governing documents as may be relevant to the proceedings. These dispute resolution procedures outline a step-by-step process for the resolution of disputes. Parties are permitted to skip steps in the dispute resolution process by mutual agreement, or as specified in the procedures for each step.

Section 4 Resolution Steps.

The four steps in the dispute resolution process are:

(a) <u>Step 1—Settlement Proceeding</u>: (i) Step 1 is a proceeding in which the parties shall meet in a good faith effort to resolve the dispute by mutual agreement ("Settlement Proceeding"). FRCC shall provide administrative support, such as making available meeting space, as requested by the parties. The parties shall be represented at settlement discussions by a person with full authority to resolve the dispute. A final resolution may be subject to corporate or regulatory or other government approvals, the requirements for which shall be disclosed by any party subject to an approval prior to agreement on a final resolution.

(ii) In the event that the parties cannot resolve their dispute in ninety (90) days from the submission of the dispute resolution request, or such later date as may be agreed to by the parties, the dispute shall proceed to the next step in the dispute resolution process. At any time after thirty (30) days from the submission of the dispute resolution request the parties may mutually agree to end the process. Any statement relating to the dispute by any party during the course of or relating to the Settlement Proceeding may not be cited or offered into evidence for any purpose in any external proceeding by any party.

(b) Step 2—Mediation Proceeding: (i) Step 2 is a proceeding to assist the parties through active participation by a mediator in joint discussions and negotiations through which the parties attempt to resolve the dispute by mutual agreement ("Mediation Proceeding"). The Mediation Proceeding shall be conducted by an independent mediator selected and mutually agreed upon by the parties ("Mediator"). A Mediator shall have no affiliation with, financial or other interest in, or prior employment with any party or any of their parents, subsidiaries or affiliates, and shall have knowledge and experience relevant to the subject matter of the dispute. In the event that the parties cannot agree on a Mediator within 10 days following the termination of the Settlement Proceeding, the President of FRCC shall select a Mediator; provided, however, that if FRCC is a party the Mediator shall be selected by the FRCC Chair, unless the FRCC Chair is an officer or employee of a party, in which case the selection shall be made by the FRCC Vice Chair. At the request of the Mediator, the parties shall be represented at a mediation session by a person with full authority to resolve the dispute. A final resolution may be subject to corporate or regulatory or other government approvals, the requirements for which shall be disclosed by any party subject to an approval prior to agreement on a final resolution.

(ii) The Mediator shall not issue specific recommendations on resolution of the dispute or otherwise opine on the merits of the dispute except at the request of the parties. A party may request the Mediator to offer his or her views on the merits or any other aspect of the dispute to that party individually on a confidential basis. Any recommendation, opinion or other statement expressed by the Mediator or any party relating to the dispute during the course of or relating to the Mediation Proceeding shall be offered solely for purposes of resolution of the Mediation Proceeding, and may not be cited or offered into evidence for any purpose in any external proceeding by any party.

(iii) In the event that the parties cannot resolve their dispute in ninety (90) days from the selection of the Mediator, or such later date as may be agreed to by the parties with the concurrence of the Mediator, the dispute shall then proceed to the next step in the dispute resolution process. At any time after sixty (60) days from selection of the Mediator, the parties may mutually agree to end the process, or a party may request the Mediator to determine and declare that the Mediation Proceeding is at an impasse. If the Mediator determines that the Mediation Proceeding is not likely to result in a resolution of the dispute, the Mediator shall declare the Mediation Proceeding at an impasse, and if so the dispute shall proceed to the next step in the dispute resolution process.

(c) Step 3—Arbitration Proceeding: (i) Step 3 is a non-binding arbitration in which an arbitrator or an arbitration panel shall receive evidence from each disputing party on factual matters, and hear arguments, relating to the issues in dispute, make written findings and conclusions of fact and law, and issue specific recommendations, based on those findings and conclusions, for resolution of each issue in dispute ("Arbitration Proceeding"). Initiation of an Arbitration Proceeding shall require the mutual agreement of the parties. The Arbitration Proceeding shall be conducted before a single arbitrator selected by the parties. Alternatively, the parties may agree to have the Arbitration Proceeding conducted by a panel of three arbitrators, with one designated by the Invoking Party or Parties, one designated by the Noticed Party or Parties, and a third selected by the two arbitrators designated by the parties. The parties may by mutual agreement engage a firm specializing in alternative dispute resolution to administer the Arbitration Proceeding, or may invoke the assistance of the Federal Energy

Regulatory Commission's Dispute Resolution Service. Arbitrators shall have no affiliation with, financial or other interest in, or prior employment with any party or any of their parents, subsidiaries or affiliates, and shall have knowledge and experience relevant to the subject matter of the dispute. The parties shall have 10 business days after conclusion of or agreement to skip the Mediation Proceeding to select a single arbitrator, or to agree on the use of an arbitration panel and to make their respective arbitrator designations and to so notify the opposing party or parties, with the arbitrators so designated selecting the third arbitrator not later than five days after the last such designation. If the parties cannot agree on the selection of a single arbitrator, unless the parties agree otherwise the President of FRCC shall provide the parties with a list of not less than five candidates meeting the qualifications set forth above. The list shall summarize the qualifications of the candidates, by experience and education, to resolve the matters at issue. The parties shall convene a meeting or telephone conference call during which the parties shall alternate striking names from the list until a single name remains, the party with the first strike to be chosen by lot. If any person so selected is or becomes unwilling or unable to serve, the last

person struck from the list shall be requested to serve. Subsequent procedures shall be determined by the arbitrator or arbitration panel, upon consideration of the recommendations of the parties, who shall seek to agree on a location for the arbitration and other procedures.

(ii) The arbitrator or arbitration panel shall issue findings of fact and law and recommendations for resolution of the dispute within ninety (90) days of appointment, unless a longer period shall be agreed to by the parties with the concurrence of the arbitrator or arbitration panel.

(d) Step 4—Board Proceeding: (i) Step 4 is a proceeding conducted by the FRCC Board (Board Proceeding) to hear formal evidence on factual matters related to the issues submitted, make written findings of fact and conclusions of law, and issue a recommended award or other resolution for each issue in dispute; provided, however, that if the parties have completed an Arbitration Proceeding as specified in Step 3, the Board shall accept the arbitrator's findings of fact except to the extent that a party demonstrates to the satisfaction of the Board that one or more findings of fact are erroneous. A party shall have 30 days from the completion of the Arbitration Proceeding to make a submission to the Board, with copies to all parties, contending that any of the findings of fact by the Arbitrator are erroneous, and any other party shall have 15 days from its receipt of the submission to respond to any such submission. Other procedures and schedules for the Board Proceeding shall be established by the FRCC Board.

(ii) The FRCC Board shall vote on the appropriate resolution of the dispute in accordance with the voting procedures described in the FRCC Bylaws. The FRCC Board shall publish the results of the vote and issue recommendations for resolution of the issues in dispute within ninety (90) days of initiation of the Board Proceeding, or such longer period as may be agreed to by the parties, with the concurrence of the FRCC Board.

(e) Further Proceedings. After 30 days from completion of the dispute resolution steps described above, to the extent that the parties have not agreed to resolution of any issue in dispute a party may seek resolution of the dispute through one of the following proceedings:

(i) By agreement of the parties, binding arbitration.

(ii) A regulatory proceeding before a state or federal regulatory agency having jurisdiction of all parties and the subject matter of the dispute.

(iii) A judicial proceeding before a court of competent jurisdiction.

Nothing in this Section 4(e) shall limit the right of a party to file a complaint, at any time, with the Federal Energy Regulatory Commission pursuant to Section 206 of the Federal Power Act.

Section 5 Administration.

The following administrative procedures apply to the dispute resolution procedures described in Section 4(a)-(d):

At each step in the process, unless the parties otherwise agree the neutral person or persons conducting the dispute resolution process shall determine meeting arrangements and formats necessary to efficiently expedite the resolution of the dispute, and shall notify the parties of these details. The parties shall seek to agree on such matters, but if after endeavoring in good faith they are unable to agree, or if they request it, the neutral authority for the proceeding shall make decisions regarding such details. The President of FRCC shall assign a member of the FRCC staff to assist those responsible for conducting the dispute resolution with the administration of the process. If the parties resolve their dispute in a proceeding prior to the Board Proceeding, the person or persons responsible for conducting the dispute resolution process shall notify the President of FRCC and the FRCC Chair of its outcome. After consultation with the parties and the individuals responsible for conducting the dispute resolution process to confirm the completion of the process described in that step, the President of FRCC, with the concurrence of the FRCC Chair if the FRCC initiated the dispute, shall discharge the persons responsible for conducting the dispute resolution process, and notify the FRCC Board of the results.

Section 6 Expenses.

The parties to the dispute shall share equally all costs for meeting locations, administrative costs, and travel and related expenses of FRCC staff members, Mediators or arbitrators administering or conducting the dispute resolution process. The parties to the dispute shall also share equally all charges for time and expenses of a Mediator, an arbitrator or an arbitration panel. The FRCC Controller shall, with the assistance of the FRCC staff members assigned to assist in the administration of the proceedings, account for these expenses. Each party to the dispute shall be responsible for its own costs and fees, including attorney fees, associated with participation in any of the proceedings described herein.

Appendix 6 to Attachment K

Examples of Cost Recovery Provisions

Example 1: per 9.4.5.A(1)

- CEERTS project where Companies A & B are incumbent enrolled transmission providers and each receive benefits from the project
- Company A is the project developer
- Company B makes a FERC-approved CIAC payment to Company A for its allocated cost and records an intangible asset in its rate base to be amortized
- Company A records CIAC as a reduction to transmission plant in service

Assumptions:	Ownership %	Initial Capital	Ongoing O&M Expense	Capital Replacements
Total CEERTS Project Cost:		$400 million	$150 million	$100 million
Company A Cost Responsibility	60%	$240 million	$90 million	$60 million
Company B Cost Responsibility	40%	$160 million	$60 million	$40 million
CIAC is not Grossed-Up for Income Taxes				

$ in Millions

Company A	Taxes Payable (Dr)	Taxes Payable (Cr)	Cash (Dr)	Cash (Cr)	Transmission Net Plant (FERC 350-359) (Dr)	Transmission Net Plant (FERC 350-359) (Cr)	Depreciation Expense (FERC 403) (Dr)	Depreciation Expense (FERC 403) (Cr)	O & M Expense (FERC 566, 573) (Dr)	O & M Expense (FERC 566, 573) (Cr)
Record Initial Project cost Spending				$ 400	$ 400					
Record Receipt of CIAC			$ 160			$ 160				
Record Annual Depreciation (30 yr life)						$ 8	$ 8			
Record On-going O&M Expense ($5M Annually)				$ 150					$ 150	
Record Receipt of O&M (40%)			$ 60							$ 60
Record Replacement Capital Expenditures				$ 100	$ 100					
Record receipt of Replacement Capital Expenditures as CIAC			$ 40			$ 40				
Record Annual Depreciation on Replacement Capital (30 yr life)						$ 2	$ 2			

Company B	Cash (Dr)	Cash (Cr)	Intangible Net Plant (FERC 303) (Dr)	Intangible Net Plant (FERC 303) (Cr)	Amortization Expense (FERC 404) (Dr)	Amortization Expense (FERC 404) (Cr)	O & M Expense (FERC 566, 573) (Dr)	O & M Expense (FERC 566, 573) (Cr)
Record Initial Payment of CIAC		$ 160	$ 160					
Record Annual Amortization (30 yr life)				$ 5	$ 5			
Record On-going O&M Expense ($5M Annually x 40%)		$ 60					$ 60	
Record Replacement Capital Expenditures		$ 40	$ 40					
Record Annual Amortization on Replacement Capital (30 yr life)				$ 1	$ 1			

Appendix 6 to Attachment K

Examples of Cost Recovery Provisions

Example 2: per 9.4.5.A(2)

- CEERTS project where Companies A & B are incumbent enrolled transmission providers and each receive benefits from the project
- Company A is the project developer and funds the entire project
- Company A files with FERC to recover its transmission revenue requirement from Company B over 30 years
- Company A reduces its transmission revenue requirements
- Company B increases its transmission revenue requirements
- Assume capital replacements are $90 million over the 30-year period
- Assume operating and maintenance expense (O&M) is $150 million over the 30-year period
- Assume total pretax return on rate base to Company A of $350 million (pretax ROR of 12%)
- Total revenue requirement due to Company A is capital, O&M, and return on capital

Assumptions:	Ownership %	Initial Capital	Ongoing O&M Expense	Capital Replacements	Return on Rate Base to Co A	
Total CEERTS Project Cost:		$400 million	$150 million	$90 million		
Company A Cost Responsibility	60%	$240 million	$90 million	$54 million		
Company B Cost Responsibility	40%	$160 million	$60 million	$36 million	$350 million	$606 due to A

$ in Millions **Company A**	Cash		Transmission Net Plant (FERC 350-359)		Depreciation Expense (FERC 403)		O & M Expense (FERC 566, 573)		Revenue (FERC 456)	
Record Project Cost Spending		$ 400	$ 400							
Record Annual Depreciation (30 yr life)				$ 13	$ 13					
Record On-going O&M Expense		$ 150					$ 150			
Record Replacement capital expenditures		$ 90	$ 90							
Record Annual Depreciation on Replacement Capital (30 yr life)				$ 3	$ 3					
Record Total Revenue Requirements from Company B	$ 606									$ 606

Company B	Cash		O & M Expense (FERC 566, 573)	
Record On-going Payment to Company A (over 30 yrs)		$ 606	$ 606	

Appendix 6 to Attachment K

Examples of Cost Recovery Provisions

Example 3: per 9.4.5.B

- CEERTS project where Companies A & B each receive benefits from the project
- Company C is a non-incumbent and the project developer and funds the entire project
- Company C files with FERC to recover its transmission revenue requirement from Company A & B over 20 years
- Company A & B increase their transmission revenue requirements
- Assume capital replacements are $90 million over the 30 year-period
- Assume operating and maintenance expense (O&M) is $150 million over the 30-year period
- Assume total pretax return on rate base to Company C of $900 million (pretax ROR of 12%)
- Total revenue requirement due to Company C is capital, O&M, and return on capital

Assumptions:	Ownership %	Initial Capital	Ongoing O&M Expense	Capital Replacements	Return on Rate Base to Co A	
Total CEERTS project cost:		$400 million	$150 million	$90 million	$900 million	
Company A cost responsibility	50%	$200 million	$75 million	$45 million	$450 million	$770 due to C
Company B cost responsibility	50%	$200 million	$75 million	$45 million	$450 million	$770 due to C

$ in Millions

Company C	Cash		Transmission Net Plant (FERC 350-359)		Depreciation Expense FERC 403		O & M Expense (FERC 566, 573)		Revenue (FERC 456)	
Record Project Cost Spending		$ 400	$ 400							
Record Annual Depreciation (30 yr life)				13	$ 13					
Record On-going O&M Expense		$ 150					$ 150			
Record Replacement Capital Expenditures		$ 90	$ 90							
Record Annual Depreciation on Replacement Capital (30 yr life)				$ 3	$ 3					
Record Total Revenue Requirements from Company A & B	$ 1,540									$1,540

Company A	Cash		O & M Expense (FERC 566, 573)	
Record on-going payment to Company C (over 30 yrs)		$ 770	$ 770	

Company B	Cash		O & M Expense (FERC 566, 573)	
Record on-going payment to Company C (over 30 yrs)		$ 770	$ 770	

FERC rendition of the electronically filed tariff records in Docket No. ER13-00104-007
Filing Data:
CID: C001030
Filing Title: FPL Order No. 1000 Further Regional Compliance Filings
Company Filing Identifier: 682
Type of Filing Code: 80
Associated Filing Identifier: 658
Tariff Title: FPL OATT
Tariff ID: 5000
Payment Confirmation:
Suspension Motion: N

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1., 2.2, 1.2.0, A
Record Narative Name:
Tariff Record ID: 909
Tariff Record Collation Value: 401204 Tariff Record Parent Identifier: 811
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

Any entity desiring to propose a CEERTS project for regional cost allocation must submit such a CEERTS project to the FRCC no later than June 1st of the first year of the biennial regional projects planning cycle. The entity proposing a CEERTS project is referred to herein as the project sponsor. The project sponsor for a CEERTS project need not be the project developer for that project.

In addition to the right of individual entities to submit potential CEERTS projects, Transmission Provider shall participate with other transmission providers and other interested entities, through the FRCC PC, in the identification and evaluation of potential CEERTS projects for submission. The FRCC PC, or a designated subcommittee thereof, shall proactively seek out potential CEERTS projects from its analysis of the most recent Board-approved plan. This will occur during the period February through April of the first year of the biennial regional projects planning cycle. The general steps of the process are as follows:

A. Gather all relevant information relating to the most recent Board-approved plan (e.g., Final Project Information Form, approved Long Range Study, early project suggestions from interested entities); and request and collect all necessary supplemental information from transmission providers and other entities (e.g., project details and cost estimates for projects identified for potential displacement, list of potentially feasible projects not selected in the initial regional transmission plan).

B. Analyze the current plan information to identify potential opportunities for CEERTS projects. Seek justification for remedies that do not have projects planned, and synergies with the planned projects that potentially could be modified, combined, or accelerated for a more cost effective or efficient regional transmission solution. The analysis will include comparative load flow studies to evaluate various potential transmission CEERTS projects. For example, comparative load flow studies will be run to identify and evaluate potential CEERTS projects that could displace transmission projects in the initial regional transmission plan.

1. If a potential CEERTS project is identified that addresses a regional reliability or economic transmission need(s) for which no transmission projects are currently planned, an analysis will be performed to identify local and/or regional alternative transmission project(s) which would also fully and appropriately address the same transmission need(s). These local and/or regional alternative transmission project(s) will be identified through comparative load flow studies. The alternative project(s) will be used to determine the Total Estimated Alternative Project Cost Benefit in the CEERTS Project Cost-Benefit Analysis described in section 1.2.9.C.

2. If a potential regional public policy transmission need has been identified for which no transmission projects are currently planned and for which no CEERTS project has otherwise been submitted for evaluation, an analysis will be performed to identify a potential CEERTS project that would satisfy that regional public policy transmission need in a least-cost manner by evaluating various potential transmission project alternatives.

C. Develop potential CEERTS project alternatives and solicit project sponsorship from enrolled transmission providers and other entities which may have an interest in sponsoring potential CEERTS projects.

1. A potential CEERTS project developed by this process will contain the following minimum set of transmission project information:

a) General description of the transmission facilities being proposed;

b) General path of the transmission lines; and

c) Transmission systems that would interconnect with the potential CEERTS project.

2. The FRCC shall post a notice on its website of any potential CEERTS projects identified through this process. Notice would be posted by May 1 of the first year of the biennial regional projects planning cycle to provide time for meeting sponsorship requirements by June 1.

3. Each identified potential CEERTS project will require at least one sponsor in order to be submitted to the FRCC for consideration. Multiple sponsors of the same project will be considered joint sponsors and shall equally share the required $100,000 deposit unless the sponsors otherwise mutually agree to a different sharing of the deposit. Potential CEERTS projects identified in this process shall not have competing sponsors for the same project. An entity that is not a sponsor

or joint sponsor of a potential CEERTS project shall not be eligible to be a developer of that project unless the sponsors discontinue development of that project.

4. The sponsor or joint sponsors shall submit the potential CEERTS project for consideration in the first year of the biennial regional projects planning cycle.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1., 2.3, 1.2.0, A
Record Narative Name:
Tariff Record ID: 910
Tariff Record Collation Value: 401483 Tariff Record Parent Identifier: 811
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

To be eligible for approval by the FRCC Board for inclusion in the regional plan, a proposed CEERTS project must meet these threshold criteria:

A. Be a transmission line 230 kV or higher and 15 miles or longer; or be a substation flexible AC transmission system ("FACTS") device, e.g., series compensation or static var compensator, designed to operate at 230 kV or more; and

B. Be materially different from projects already in the regional plan. For purposes of this section, the FRCC will consider a CEERTS project to be materially different from another CEERTS project if it displaces a different local project or projects or is not considered a minor adjustment to an existing local or CEERTS project that it is displacing. Minor adjustments could include changes in equipment size, different terminal bus arrangement, or a slight change in route.

Local transmission facilities located solely within a Transmission Provider's footprint (e.g. Control Area) that are not selected in the regional transmission plan for purposes of cost allocation cannot qualify as CEERTS projects. Such facilities are the responsibility of the Transmission Provider to meet reliability needs and/or other obligations within its retail distribution service territory or footprint.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1., 2.7, 1.2.0, A
Record Narative Name:
Tariff Record ID: 914
Tariff Record Collation Value: 401744 Tariff Record Parent Identifier: 811
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1

During the succeeding three to five months following the FRCC Board meeting in section 1.2.6, for those CEERTS projects that cleared sections 1.2.3 through 1.2.5 above, the FRCC PC, together with an independent consultant, will conduct a technical analysis for the purpose of either developing CEERTS project information or validating CEERTS project information and analysis provided by the sponsor. Such analysis will be performed in a manner consistent with other technical analyses performed by the FRCC PC. This may be referred to as Step 3.

A. The development/validation process will either develop the needed CEERTS project parameters or validate the information and analysis provided by the sponsor. This analysis will examine the following:

1. Transmission project technical information:

a) Description of the transmission facilities being proposed (*e.g.*, voltage levels);

b) General path of the transmission lines; and

c) Interconnection points with the existing transmission system.

2. Load flow analysis that demonstrates adequate NERC Reliability Standards performance utilizing the FRCC load flow model;

3. Whether it can be demonstrated through a technical evaluation process that the CEERTS project is equal to or superior to avoided projects from the current regional transmission plan or equal to or superior to the alternative transmission project(s) that address(es) the same transmission need(s), which alternative must be identified if there are no transmission projects currently planned for the relevant transmission need(s) (see section 1.2.2.B);

a) The FRCC PC shall verify that the proposed CEERTS project addresses transmission need(s) for which there are no transmission projects currently planned, and that the alternative project(s) to the CEERTS project could also meet such need(s). After the alternative project(s) are verified to meet such needs, the FRCC PC shall request that the entities responsible for the alternative project(s) provide cost information to the FRCC PC to be used in the FRCC PC's analysis;

4. Identification of projects in the regional transmission plan that would be affected or avoided as well as any additional projects that may be required.

a) The FRCC PC shall request that the entities responsible for the existing project(s) that could be impacted by the proposed CEERTS project, or entities who would be required to implement additional local projects provide cost information to the FRCC PC to be used in their analysis;

5. Cost estimate for the proposed CEERTS project; and

6. In-service date for the project.

B. The FRCC PC will also consider any proposed non-transmission alternatives on a comparable basis with the CEERTS project, as described in section 5.

C. The FRCC PC will provide the CEERTS sponsor and stakeholders an opportunity to review and provide input on a report that includes its findings from the technical analysis performed, and then the report will be provided to the FRCC Board with a recommendation as to whether the proposed CEERTS project should proceed to the next evaluation step in section 1.2.8 below. The CEERTS sponsor and stakeholders shall be given 15 days to provide written comments on the report to the FRCC Board following the date on which the FRCC PC provides the report and its recommendations to the Board.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1., 2.9, 1.2.0, A
Record Narative Name:
Tariff Record ID: 916
Tariff Record Collation Value: 401757 Tariff Record Parent Identifier: 811
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

Over a period of two to four months from FRCC Board approval of the continuation of the CEERTS project evaluation in section 1.2.8, the process described below will be performed by the FRCC PC under the direction of the FRCC Board. This may be referred to as Step 5.

A. A meeting will be organized by the FRCC PC to provide the CEERTS sponsor an opportunity to fully describe its proposed CEERTS project. This meeting is the venue to fully discuss the CEERTS project, taking into account the technical analysis performed by the FRCC PC, as well as any potential revisions, including transmission technical aspects, transmission project costs, and affected projects. This meeting also provides the opportunity for potentially affected transmission providers to discuss these matters. If no developer is a sponsor of the proposed project, then this meeting also provides an opportunity for potential developers to express interest in being considered as the developer of the CEERTS project (if no entity expresses interest as the project developer then the project will not move forward and the projects in the regional plan that would have been avoided by the CEERTS project will remain in the regional plan). If multiple qualified project developers express an interest in developing a CEERTS project for which the sponsor does not plan to be the developer, then such developers must each submit, within the 30 days following the meeting held pursuant to this section 1.2.9.A, the project information identified in section 1.2.4.B.2 through 1.2.4.B.4 and these project developer proposals will be evaluated in the remainder of the steps identified in sections 1.2.9 and 1.2.10. This forum will enable the CEERTS project to be fully reviewed by all affected parties.

B. The FRCC PC will consider the proposed project in light of the criteria set forth in sections 1.2.7.A. and 1.2.7.B above and as set forth below.

1. A cost-benefit analysis must be performed in accordance with section 1.2.9.C for reliability/economic projects by an independent consultant. If the result of this analysis is a benefit-to-cost ratio of greater than 1.00, the CEERTS project will move forward in the process.

2. For a project proposed to meet a public policy transmission need that requires a solution, as verified by the FRCC PC under section 11, the FRCC PC will determine whether the proposed CEERTS project meets the public policy transmission needs identified. There is no cost-benefit analysis performed, except for the validation of the CEERTS project being the least-cost solution. The CEERTS project may be the only solution proposed, in which case it would be accepted in accordance with the project sponsorship model being used within the FRCC. However, in the event there are equally effective alternative CEERTS project solutions that have been proposed to satisfy the public policy transmission needs, then the least-cost CEERTS project would be selected.

The total estimated cost of the CEERTS public policy project is determined by the methodology set forth in section 1.2.9.C.4.

C. CEERTS Project Cost-Benefit Analysis

An independent consultant will be retained to perform a cost-benefit analysis and will issue a written report of findings to the FRCC PC for sponsor and stakeholder review as set forth in section 1.2.9.D. The independent consultant will determine if the benefit-to-cost ratio, which is the sum of the "Total Estimated Avoided Project Cost Benefit," "Total Estimated Alternative Projects Cost Benefit" and "Total Estimated Transmission Line Loss Value Benefit" divided by the "Estimated CEERTS Project Cost," is greater than 1.0.

Such analysis will consider estimated costs and benefits for the 10-year period of the planning horizon that is used to prepare the regional transmission plan under development at the time the analysis is prepared plus an additional, sequential 10-year period (the "20-year period"). Levelized annual costs and benefits to determine the appropriate revenue requirements will be used and deemed appropriate.

1. Total Estimated Avoided Project Cost Benefit

The Estimated Avoided Project Cost Benefit for each enrolled transmission provider in the FRCC that has one or more projects being displaced by a CEERTS project will be determined by the independent consultant in the below manner. A CEERTS project that was previously selected and included in the most recent Board-approved transmission plan may be displaced by a newly-proposed CEERTS project. If a newly-proposed CEERTS project would displace a previously-approved CEERTS project, the portion of the costs of the newly-proposed CEERTS project associated with the benefits calculated using the costs of the displaced previously-approved CEERTS project would be allocated to the enrolled transmission providers that were allocated the costs for the previously-approved CEERTS project (see Appendix 4, Example 4 for a hypothetical example of this cost allocation process).

Each enrolled transmission provider that has one or more projects being displaced is considered a beneficiary of the proposed transmission facility(ies) and will develop an original installed capital cost estimate for each project being displaced and indicate in what year each such project would be projected to be in service.

The independent consultant will review each enrolled transmission provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate, depending on which will be used for further calculations, for each year that the displaced project would have been expected to be in service during the 20-year period, but for the CEERTS project. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the enrolled transmission provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements for each project will be determined using the average discount rate of enrolled transmission providers weighted by their total capitalization (Enrolled TP Discount Rate). Each enrolled transmission provider will provide its discount rate and total capitalization to the independent consultant for purposes of this calculation. Such net present value will be the "TP Estimated Avoided Project Cost Benefit" for each enrolled transmission provider's displaced project(s).

All such TP Estimated Avoided Project Cost Benefits will be summed to determine the Total Estimated Avoided Project Cost Benefit.

2. Total Estimated Alternative Projects Cost Benefit

The Estimated Alternative Project Cost Benefit for each enrolled transmission provider in the FRCC that has one or more alternative projects for which a CEERTS project addresses a need for which there are no transmission projects currently planned will be determined by the independent consultant in the below manner. These projects will include those alternative transmission projects to a CEERTS project that were identified under section 1.2.2.B.1:

Each enrolled transmission provider that has one or more alternative projects is considered a beneficiary of the proposed transmission facility(ies) and will develop an original installed capital cost estimate for each alternative project and indicate in what year each such project would be needed to be in service.

The independent consultant will review each enrolled transmission provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate, depending on which will be used for further calculations, for each year that the alternative project would have been expected to be in service during the 20-year period, but for the CEERTS project. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the enrolled transmission provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements for each project will be determined using the average discount rate of enrolled transmission providers weighted by their total capitalization (Enrolled TP Discount Rate). Each enrolled transmission provider will provide its discount rate and total capitalization to the independent consultant for purposes of this calculation. Such net present value will be the "TP Estimated Alternative Project Cost Benefit" for each enrolled transmission provider's displaced project(s).

All such TP Estimated Alternative Project Cost Benefits will be summed to determine the Total Estimated Alternative Project Cost Benefit.

3. Total Estimated Transmission Line Loss Value Benefit

The Total Estimated Transmission Line Loss Value Benefit is calculated for each enrolled transmission provider by the independent consultant as follows:

The change in transmission losses caused by the CEERTS project will be determined by the FRCC PC.

The FRCC PC will run simulations of the approved transmission plan with all projects, adjusted (if necessary) to include the alternative transmission projects that were identified that would have been needed to satisfy a transmission need for which no transmission projects are in the current transmission plan (see section 1.2.2.B), to establish base transmission losses for each enrolled transmission provider represented in the plan over the planning horizon. Base case losses will be determined for the years during which the CEERTS project is expected to be in service during the planning horizon, under both peak and off-peak conditions.

The approved transmission plan will then be modified to (1) include a proposed CEERTS project; (2) remove all alternative transmission projects; and (3) adjust or remove any affected or avoided transmission projects in the approved transmission plan as well as add any additional projects that would be required (see section 1.2.7.A.4) (after verifying that all reliability requirements are met) with the appropriate in-service dates. The modified plan is then analyzed for losses. The CEERTS case losses are determined for each enrolled transmission provider represented in the plan for the years during which the CEERTS project is expected to be in service during the planning horizon, at both peak and off-peak conditions. Enrolled transmission providers with reduced losses are beneficiaries of the CEERTS project.

The change in losses for year 10 of the planning horizon will be held constant for years 11-20 of the 20-year period. The change in losses (whether negative or positive) in each year that the CEERTS project is in service for the 20-year period is determined for each enrolled transmission provider.

The value of the change in losses for each enrolled transmission provider will be determined by the independent consultant as follows:

The independent consultant will use fuel cost and heat rate data from the U.S. Energy Information Administration ("EIA") to value losses.

The net present value of the value of losses will be determined for each enrolled transmission provider using the Enrolled TP Discount Rate.

Such net present value will be the "TP Estimated Transmission Line Loss Value Benefit."

The TP Estimated Transmission Line Loss Value Benefit for each enrolled transmission provider will be summed to determine the Total Estimated Transmission Line Loss Value Benefit.

4. Estimated CEERTS Project Cost

The Estimated CEERTS Project Cost is determined using the following formula:

Estimated CEERTS Project Cost = Estimated Developer Cost + Total Estimated Related Local Project Costs + Total Estimated Displacement Costs

The Estimated Developer Cost will be determined by the independent consultant as follows:

The developer of a CEERTS project will provide an original installed capital cost estimate for the developer's project and indicate which year the project is expected to be in service.

The independent consultant will review the developer's original cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate for the developer's project, depending on which will be used for further calculations, for the years during which the CEERTS project is expected to be in service during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the rates of return on equity approved by FERC for the developer or its affiliates (if any); commitments regarding incentive rates; proposed weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements will be determined using the Enrolled TP Discount Rate. The net present value of these estimated annual revenue requirements shall be the Estimated Developer Cost.

The Total Estimated Related Local Project Cost will be determined as follows by the independent consultant:

Each enrolled transmission provider that will need to construct a local project to implement the CEERTS project will develop an original installed capital cost estimate for each such related local project and indicate what year such project is projected to be in service.

The independent consultant will review the enrolled transmission provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate for each year that the local project is expected to be in service during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the enrolled transmission provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirement for each local project will be determined using the Enrolled TP Discount Rate. Such net present value will be the TP Estimated Avoided Project Cost for the displaced project.

All TP Estimated Related Local Project Costs will be summed to determine the Total Estimated Related Local Project Cost.

The calculation of Total Estimated Displacement Cost will be performed by the independent consultant as follows:

Any enrolled transmission provider that has incurred, or expects to incur, costs associated with a project that is being displaced by a CEERTS project will provide an accounting to the independent consultant as to the level of its actual and expected expenditure on any displaced projects and any planned mitigation of such expenditures. The independent consultant will review the displacement cost estimate. The independent consultant will estimate the level of displacement cost that the enrolled transmission provider that has expended funds on a displaced project will recover by assuming that the enrolled transmission provider will be permitted to recover 100% of such displacement costs. The independent consultant will calculate an annual transmission revenue requirement associated with the displacement cost estimate for each year so that the displacement costs would be recovered during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions and will describe such relevant factors and assumptions used in the report. The net present value of the estimated annual revenue requirements shall be calculated using the Enrolled TP Discount Rate. Such net present value will be the Estimated Displacement Cost.

All such Estimated Displacement Costs will be summed to determine the Total Estimated Displacement Cost.

D. The FRCC PC will provide the CEERTS sponsor and stakeholders an opportunity to review and provide input on a report that includes its findings from the cost-benefit analysis performed that determined how benefits and beneficiaries were identified and applied to a proposed CEERTS project. The report will then be provided to the FRCC Board with the FRCC PC's recommendation based upon its review as set forth above. For any CEERTS public policy project(s), this report will include an explanation of why the CEERTS project(s) does or does not provide an opportunity to satisfy the public policy need. The CEERTS public policy analysis is more completely described in section 11.1. The CEERTS sponsor and stakeholders shall be given an opportunity to also provide written comments on the report to the FRCC Board. The CEERTS sponsor shall be invited to be present and participate in any FRCC Board meeting that addresses the FRCC PC report to answer questions and to present its views regarding the CEERTS project and the FRCC PC report.

E. The FRCC Board will review the FRCC PC report and any comments on the report that may be provided by the CEERTS sponsor and stakeholders and determine if the proposed CEERTS project is a more cost effective or efficient solution to regional transmission needs under applicable criteria in this section 1.2.9 and section 11.1.

F. If a CEERTS project is selected, the FRCC will perform analyses to determine whether the CEERTS project could potentially result in reliability impacts to the transmission system(s) in another transmission planning region. If a potential reliability impact is identified, the FRCC will coordinate with the public utility transmission providers in the other transmission planning region on any further evaluation. The evaluation may identify required upgrades in the other transmission planning region. The costs of those upgrades are addressed in section 9.4.6.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1., 2.10, 1.2.0, A
Record Narative Name:
Tariff Record ID: 917
Tariff Record Collation Value: 401759 Tariff Record Parent Identifier: 811
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE

Record Content Type: 1
Associated Filing Identifier: 658

Over a period of two to three months following a decision that a CEERTS project should move forward under section 1.2.9, the following "Transmission Project Developer and Project Selection Process" will occur. This may be referred to as Step 6.

A. If the CEERTS project requires upgrades to an enrolled transmission provider's existing facilities that enrolled transmission provider retains a right-of-first refusal to build those portions of the CEERTS project. As used in this section the term "upgrade" means an improvement to, addition to, or replacement of a part of an existing transmission facility; the term does not refer to an entirely new transmission facility. Nothing herein affects an enrolled transmission provider's rights under state law with regard to its real property (including rights of way and easements).

B. If a single project sponsor is also the developer identified for a given CEERTS project, then that project sponsor/developer is accepted by default as the project developer eligible to use the regional cost allocation for that CEERTS project (subject to the qualifications review below). If there are different proposed CEERTS projects to address the same transmission need(s), then the CEERTS project will be selected based on the highest benefit-to-cost ratio as determined in section 1.2.9.C and once a project sponsor/developer's proposed CEERTS project is selected in the regional transmission plan, that project sponsor/developer will also be selected as the project developer eligible to use the regional cost allocation for that CEERTS project, subject to the project developer qualifications review. CEERTS projects proposed by a single qualified project developer and selected by the FRCC Board will not be assigned to a different project developer.

C. If there are multiple project developers for the same CEERTS project, then the FRCC Board will, upon request, facilitate an opportunity for the project sponsors/developers to collaborate with each other to determine how each of the project developers may share responsibility for portions of the CEERTS project(s). If agreement is reached, then these project sponsors/developers will be selected (subject to the qualifications review below). If there is no agreement then the project developer for the CEERTS project will be selected based on the highest benefit-to-cost ratio as determined in section 1.2.9.C.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1., 2.11, 1.2.0, A
Record Narative Name:
Tariff Record ID: 918
Tariff Record Collation Value: 401760 Tariff Record Parent Identifier: 811
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

Project Developer Qualifications Review

A. Project developers (both incumbent and non-incumbent project developers) that are submitting for the first time a qualification application must submit the application and a deposit of $50,000 to the FRCC along with the information identified in the Qualification Criteria as set forth in Appendix 3 of this Attachment K. The deposit will be used by the FRCC Board to fund the internal FRCC labor cost for application review, which will be documented, and expenses for the independent consultant for the review described in the next section. Any unexpended amounts from the deposit, including interest, shall be refunded to the project developer. The transmission developer will be provided with an accounting of the actual costs and how the costs were calculated. Any disputes related to the accounting for specific deposits shall be addressed under the Dispute Resolution Procedures in Appendix 5. A project developer may be a joint venture or a partnership in which case a lead representative will be designated in the qualification application. Project developers that already have been found qualified after a review by the FRCC must submit an attestation to maintain their qualification as discussed in Appendix 3. If sufficient changes, as determined by the FRCC, have been identified in the attestation by a project developer which had previously been qualified, then a deposit of $10,000 to the FRCC will be required during the attestation review process. This deposit will be handled in a similar manner as described above for the initial project developer qualification review.

B. The FRCC Board will provide for the review of the submitted qualifications by an independent consultant. The consultant fees will be paid from the deposit made when a project developer qualification application is submitted. The consultant will make a recommendation to the FRCC Board as to whether the Qualification Criteria have been met. The FRCC Board shall make, on a non-discriminatory basis, a determination as to whether the Qualification Criteria have been met. If the FRCC Board determines that the Qualification Criteria have not been met, the FRCC Board will notify the project developer of the qualification deficiencies and provide a 30-day period for the project developer to cure the deficiencies. If a project developer does not agree with the FRCC Board's determination, then the Dispute Resolution Procedures in Appendix 5 are available for use by the project developer. The qualification process is a one-time process for each project developer, subject to the attestation review process provided for in Appendix 3.

C. The timeline for the project developer qualification review evaluation process is set forth below:

1. By January 1 of the first year of a biennial regional projects planning cycle, any potential developer that seeks to be qualified to develop CEERTS projects during this cycle must submit its qualifications to the FRCC. Biennial attestations also must be submitted at this time.

2. In January through March of the first year of a biennial regional projects planning cycle, FRCC shall coordinate the qualifications review.

3. By April 1 of the first year of a biennial regional projects planning cycle, the FRCC Board will inform developers that have submitted qualifications or attestations that they have either met the qualification criteria or the FRCC Board will identify deficiencies in the submitted qualifications/attestations.

4. From April 1 through April 30 of the first year of a biennial regional projects planning cycle,

developers will have an opportunity to cure deficiencies and resubmit their modified qualifications/attestations.

5. From May 1 through May 31 of the first year of a biennial regional projects planning cycle, the FRCC Board shall reexamine the modified qualifications/attestations, make final determinations, and notify developers, FRCC members and other stakeholders.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1., 2.12, 1.2.0, A
Record Narative Name:
Tariff Record ID: 919
Tariff Record Collation Value: 401763 Tariff Record Parent Identifier: 811
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

Approval and Certification after Conclusion of the Project Developer Determination and Qualifications Review

A. At the next FRCC Board meeting after successful completion of the items in sections 1.2.3 through 1.2.11 above, the FRCC Board will notify the project developer to proceed with the project as it has been approved for inclusion in the regional transmission plan. It is at this point that any transmission projects currently in the regional transmission plan that are being avoided due to the new CEERTS project will be removed from the regional transmission plan. The project developer(s) shall then proceed with obtaining the necessary approvals and/or permits required to construct, own and operate the project, including certification under the Transmission Line Siting Act.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1., 2.14, 1.2.0, A
Record Narative Name:
Tariff Record ID: 921
Tariff Record Collation Value: 401766 Tariff Record Parent Identifier: 811
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

As identified in section 1.2.2, new CEERTS projects are to be submitted by June 1 of the first year of each biennial regional projects planning cycle. The technical evaluation of a new CEERTS project will occur within approximately 12 months concurrent with the evaluation of the initial FRCC regional transmission plan, and final approval will be achieved within 19 months. This time period may be shorter for some CEERTS projects, such as where the project developer has previously satisfied qualification criteria and/or the project is relatively small in scale. Following the evaluation steps identified in this section 1.2 for a newly proposed CEERTS project, a sponsor can expect the project to be analyzed with the regional transmission plan as a tentative project in the summer or fall of the following year. For the project to remain in the regional transmission plan, the remainder of the process must be completed. For example, a new CEERTS project that was proposed by June 1 in biennial year 1 would proceed through section 1.2.7 in the fall of biennial year 1 through the winter of biennial year 2. In the spring and summer of biennial year 2, the project would progress through the items in section 1.2.9 and be tentatively added to the regional transmission plan. Successful completion of the items in sections 1.2.10 through 1.2.12 would qualify the project for final approval in December of biennial year 2, roughly 19 months after it was initially proposed. This overall schedule provides a roadmap of the projected schedule for new CEERTS project evaluation, selection, approval and ultimate reflection in the regional transmission plan within the mandatory two year (biennial) planning cycle. A particular CEERTS project submittal may benefit from schedule flexibility or shortening of process steps depending on the project's nature or complexity, availability of qualified project developer(s), or other factors. In all cases, once a CEERTS project is submitted, the FRCC will keep all parties informed of the projected schedule for project evaluation. This CEERTS project evaluation process will fold into the overall regional transmission planning cycle, which will continue to be an annual process, that is, a regional transmission plan will continue to be developed each year. The inclusion of the CEERTS projects into the annual regional transmission plan will be in accordance with the process outlined above.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1., 2.18, 1.2.0, A
Record Narative Name:
Tariff Record ID: 925
Tariff Record Collation Value: 401770 Tariff Record Parent Identifier: 811
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

If a delay in the completion of a CEERTS reliability-based project potentially would cause Transmission Provider or other NERC-registered entity to violate a Reliability Standard, the NERC-registered entity shall inform the FRCC as soon as it is aware of the possibility. The FRCC PC will re-evaluate the regional transmission plan to determine if the delay in the CEERTS project requires the evaluation of alternative solutions to ensure the relevant Transmission Provider or other NERC-registered entity can continue to meet its reliability and/or other service obligations. If the FRCC PC determines that the delay in the CEERTS project would adversely affect reliability (e.g., would cause a violation of one or more NERC reliability standards), the FRCC PC will initiate a process to evaluate solutions to address the reliability concerns. The transmission providers whose system(s) are affected by these reliability concerns will be given an opportunity to propose solutions that they would implement within their service territories or footprints to address these reliability concerns, and their proposals can be evaluated as possible CEERTS projects if such transmission providers agree. The FRCC PC will fully evaluate the original CEERTS project delay along with any proposals for alternate solutions and will make a determination on how to proceed in a timely manner to ensure that the FRCC regional transmission plan supports the adequate planning for a reliable transmission system for the FRCC region. Where possible, the review of a CEERTS project delay will be included within the biennial regional transmission planning cycle. However, if the FRCC PC determines that a CEERTS project delay needs to be evaluated outside of the biennial regional projects planning cycle, the FRCC PC will notify the members and establish a schedule for the evaluation process. The FRCC PC will follow similar steps that are identified in sections 1.2.9.C and 1.2.9.D to develop a report of the results of their evaluation and provide their findings to the FRCC Board for ultimate resolution.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
1.3.1, , 2.1.0, A
Record Narative Name:
Tariff Record ID: 814
Tariff Record Collation Value: 402878 Tariff Record Parent Identifier: 813
Proposed Date: 2015-01-01
Priority Order: 700
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

This coordinated *FRCC Regional Transmission Planning Process* offers many opportunities for transmission providers to interact with customers and neighboring systems during the development of the transmission plan. The schedule of committee and working group meetings related to transmission planning is posted on the FRCC website under *FRCC Calendar*.

FRCC meeting notices, meeting minutes and documents of FRCC PC and/or FRCC Board meetings in which transmission plans or related study results are exchanged, discussed or presented are distributed by the FRCC. Detailed evaluation and analysis of the transmission providers/owners plans are conducted by the FRCC Transmission Working Group ("TWG") and Stability Working Group ("SWG") in concert with the FRCC Staff. The TWG and SWG are further described below.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
2.1, , 2.1.0, A
Record Narative Name:
Tariff Record ID: 818
Tariff Record Collation Value: 407342 Tariff Record Parent Identifier: 817
Proposed Date: 2015-01-01
Priority Order: 700
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

Transmission Provider provides notice and schedules meetings with its transmission customers as deemed necessary by the transmission customer and/or Transmission Provider. Transmission Provider schedules meetings with its customers to interact, exchange perspectives or share findings from studies. Transmission Provider communicates and interacts with its transmission service customers on a regular basis to discuss loads, generation/network resource additions/deletions, new facility additions and upgrades, demand resource information, customers' projections of future needs, and related subjects that have an impact on the provision of transmission service to a customer. Transmission Provider provides a status update to its customers on a regular basis or at any time, if requested by a customer. Additionally, Appendix 1 to this Attachment K describes the customer and Transmission Provider interaction in the flow diagram and outlines the steps of the Local Transmission Network Planning Process.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
2.2, , 2.2.0, A
Record Narative Name:
Tariff Record ID: 819
Tariff Record Collation Value: 408458 Tariff Record Parent Identifier: 817
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

This openness principle is also incorporated in the *FRCC Regional Transmission Planning Process* by which the Transmission Provider participates, along with other parties, in the committee and working processes at the FRCC as described below. The participants in the planning process at the FRCC are the sector representative of the FRCC PC. A list of representatives may be found on the FRCC website under the *FRCC PC Member List.* The *Rules of Procedure for FRCC Standing Committees* document on the FRCC website describes the FRCC PC structure and processes as they relate to Organization Structure, Standing Committee Representation, Standing Committee Quorum and Voting, Duties of Officers and Representatives, General Procedures for Standing Committees, FRCC Representation on NERC Committees, Procedures of Minutes of Meetings and Conduct of the Meeting. Interested entities or persons may participate in the committees via participation within one of the identified sectors (Supplier Sector, Non-Investor Owned Utility Wholesale Sector, Load Serving Entity Sector (including municipals and cooperatives), Generating Load Serving Entity Sector, Investor Owned Utility Sector, and General Sector (this sector provides for any entity or individual's participation)). Moreover, at the FRCC regional level interested entities have an opportunity to raise any special requirements that they have and believe have not been addressed at the local level. For ease of reference, the FRCC quorum and voting provisions are shown in Appendix 2 of Attachment K.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
2.3, , 2.1.0, A
Record Narative Name:

Tariff Record ID: 822
Tariff Record Collation Value: 411806 Tariff Record Parent Identifier: 817
Proposed Date: 2015-01-01
Priority Order: 700
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

Customer input is included in the early stages of the development of the transmission plans, as well as during and after plan evaluation processes. Detailed evaluation and analysis of the transmission providers'/owners' plans are conducted by the FRCC Transmission Working Group and Stability Working Groups under the direction of the FRCC PC. Such evaluation and analysis provides the basis for possible changes to the transmission providers'/owners' plans that could result in a more reliable and more robust transmission system for the FRCC Region. The FRCC PC meets on a regular basis, usually monthly, with two weeks prior notice.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
3.2, , 2.1.0, A
Record Narative Name:
Tariff Record ID: 827
Tariff Record Collation Value: 417386 Tariff Record Parent Identifier: 825
Proposed Date: 2015-01-01
Priority Order: 700
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

During the Transmission Provider's local area planning process the Transmission Provider utilizes the FRCC databanks which contain information provided by the Transmission Provider and customers of projected loads as well as all planned and committed transmission and generation projects, including upgrades, new facilities and changes to planned-in-service dates over the planning horizon, as the base case for Transmission Provider's studies. Transmission Provider makes available to a transmission service customer the underlying data, assumptions, criteria and underlying transmission plans utilized in the study process. Transmission Provider provides written descriptions of the basic methodology, criteria and processes used to develop plans. In order to get a better understanding, a transmission customer may inquire about the assumptions, data and/or underlying methods, criteria, etc. and the customer will be provided a response by the Transmission Provider's qualified technical representative. Dialogue during the study process is encouraged. The dialogue during the Transmission Provider's local area planning process between the Transmission Provider and customers involves discussions of the initial findings that affect customers, potential alternatives including feasibility of mitigating any adverse findings, and third party impacts. Discussion of initial findings in areas of the system that affect customers is intended to communicate and validate with the customer issues or concerns identified by the Transmission Provider or conversely, issues not specifically identified by the Transmission Provider that may be of concern to the customers. As part of the process of identifying potential alternatives to mitigate any adverse issue or concern, the dialogue with the customer should facilitate the identification of the most effective solution. This dialogue during the different stages of the planning process provides for meaningful input and participation of transmission customers in the development of the transmission plan. The goal of this interaction between the Transmission Provider and customers is to develop a transmission expansion plan that meets the needs of the Transmission Provider and customer in a reliable cost effective manner. This planning process between the Transmission Provider and customers is described in the process flow diagram below and in the more detailed description of the Local Transmission Network Planning Process as set forth in Appendix 1 to this Attachment K.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
3.3, , 2.1.0, A
Record Narative Name:
Tariff Record ID: 828
Tariff Record Collation Value: 418502 Tariff Record Parent Identifier: 825
Proposed Date: 2015-01-01
Priority Order: 700
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

An overview of the Transmission Provider’s local area planning process and how it relates to the *FRCC Regional Transmission Planning Process* is shown in the flow chart below:

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
3.4, , 2.1.0, A
Record Narative Name:
Tariff Record ID: 829
Tariff Record Collation Value: 419618 Tariff Record Parent Identifier: 825
Proposed Date: 2015-01-01
Priority Order: 700
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

Once the results of the Transmission Provider's local area planning process are reflected in the *FRCC Regional Transmission Planning Process*, the FRCC seeks input and feedback from transmission customers/users for any issues or concerns that are identified and independently assesses the initial regional transmission plan from a FRCC regional perspective. A dialogue among the FRCC, transmission customers/users, and transmission owners/providers occurs to address any issues identified during this process. When the FRCC regional transmission plan has been approved by the FRCC PC, it is sent to the FRCC Board for approval. After the FRCC Board approves the FRCC regional transmission plan, it is posted on the FRCC website and sent to the FPSC. Additionally, the FRCC compiles all of the individual transmission providers'/owners' FERC Form 715s within the FRCC region, including Transmission Provider's, and files all FERC Form 715s for its members with the FERC on an annual basis.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
4.2, , 2.1.0, A
Record Narative Name:
Tariff Record ID: 834
Tariff Record Collation Value: 425198 Tariff Record Parent Identifier: 832
Proposed Date: 2015-01-01
Priority Order: 700
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

The Transmission Provider utilizes the information provided in modeling and assessing the performance of its system in order to develop a transmission plan that meets the needs of all customers of the transmission system. The Transmission Provider exchanges information with a transmission customer to provide an opportunity for the transmission customer to evaluate the initial study findings or to propose potential alternative transmission solutions for consideration by the Transmission Provider. If the Transmission Provider and transmission customer agree that the transmission customer's recommended solution is the best overall transmission solution then such solution will be incorporated in the Transmission Provider's plan. Through this information exchange process the transmission customer has an integral role in the development of the transmission plan. This process is described in greater detail in Appendix 1 to this Attachment K. Consistent with the Transmission Provider's obligation under federal and state law, and under NERC and FRCC reliability standards, the Transmission Provider is ultimately responsible for the transmission plan.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
9.2, , 2.1.0, A
Record Narative Name:
Tariff Record ID: 857
Tariff Record Collation Value: 450866 Tariff Record Parent Identifier: 855
Proposed Date: 2015-01-01
Priority Order: 700
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

The FRCC Principles for Sharing of Certain Transmission Expansion Costs: (i) sets forth certain principles regarding the provision of financial funding to Transmission Owners (note: for this purpose, "Transmission Owner" means an electric utility owning transmission facilities in the FRCC Region) that undertake remedial upgrades to, or expansions of, their systems resulting from upgrades, expansions, or provisions of services on the systems of *other* Transmission Owners, and (ii) procedures for attempting to resolve disputes among Transmission Owners and other parties regarding the application of such principles. These principles shall not apply to transmission upgrades or expansions if, and to the extent that, the costs thereof are subject to recovery by a Transmission Owner pursuant to FERC Order No. 2003 or Order No. 2006.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:

9.4.4, , 1.1.0, A
Record Narative Name:
Tariff Record ID: 936
Tariff Record Collation Value: 476464 Tariff Record Parent Identifier: 879
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

The costs for CEERTS public policy projects that are identified through the process described in section 11 will be allocated to the enrolled transmission providers whose transmission systems provide access to the public policy resources. The cost allocation for each enrolled transmission provider will be as follows:

- Individual enrolled transmission provider MWs = number of megawatts of public policy resources enabled by the public policy project for the customers (including Native Load) within their transmission service territory.

- Total MWs = total number of megawatts of public policy resources enabled by the public policy project.

- Individual enrolled transmission provider cost allocation percentage = (Individual enrolled transmission provider MWs/Total MWs).

An example of the CEERTS public policy cost allocation is provided in Appendix 4, Example 3. These percentages will be used to allocate actual CEERTS project costs that are recoverable pursuant to the applicable subsection of section 9.4.5.

The process to interconnect individual generation resources is provided for under the generator interconnection section of each utility's OATT and not under this process.

Requests for transmission service that originate in a utility's system and terminate at the border shall be handled through that utility's OATT.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
9.4.5, , 1.2.0, A
Record Narative Name:
Tariff Record ID: 940
Tariff Record Collation Value: 476520 Tariff Record Parent Identifier: 855
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

Transmission Project Funding and Rate Base/Cost Recovery:

A. If incumbent enrolled transmission providers are the only transmission developers for a particular project, then they shall have two options in the initial transmission project funding and subsequent cost recovery of developer costs. Note that if an incumbent enrolled transmission provider develops a CEERTS project and is not FERC-jurisdictional, it will make any requisite FERC filings through the declaratory order process used for non-jurisdictional enrolled transmission providers rather than under FPA section 205:

(1) Incumbent enrolled transmission providers may fund the transmission project in proportion to their cost responsibility for the project. For the portions of the projects that each of the companies were building that are related to their cost responsibility, the companies would include those transmission costs as identified in a Contribution in Aid to Construction (CIAC) filing at FERC within their respective rate bases and transmission revenue requirements. The costs would be reflected in FERC filed OATT rates in Account 107, Construction Work in Progress. When the assets go into service, the balance will be moved to Account 101, Electric Plant in Service and the Units of Property will be unitized to the FERC Accounts corresponding to the Units of Property. This treatment is for accounting purposes: a FERC filing and FERC approval would still be required to include Construction Work in Progress in rates. For the portion of the funding that was being provided for the transmission to be built by someone other than the incumbent, the payments by the incumbent (for their cost responsibility) would be recorded in Account 303, Miscellaneous Intangible Plant and amortized by debiting Account 404, Amortization of Limited-Term Electric Plant, and crediting Account 111, Accumulated Provision for Amortization of Electric Utility Plant. The amortization of the investment would be derived using a composite factor based on the most recently approved depreciation rates for the constructing company. The calculation of the composite factor would be based on the Units of Property installed in the transmission project. The amortization will begin when the project is declared in service. The costs and amortization would be reflected in FERC filed OATT rates until the investment is fully amortized to expense. The company receiving the money would treat these monies as a CIAC and thus have no associated net book investment in its transmission rate base. CIAC agreements will be filed with FERC prior to any CIAC payments being made to the constructing developer. Enrolled transmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC for authorization to include the intangible asset investment and amortization expense in the formula rate. Traditional cost-based ratemaking procedures would be used to determine the impact of including the intangible asset investment in rate base and the amortization expense in operating expenses in deriving OATT rates. CIAC agreements filed with FERC would include workpapers to support the costs included in the determination of revenue requirements. See Example 1 provided in

Appendix 6 for more detail and accounting treatment.

(2) Incumbent enrolled transmission providers may fund the portion of the transmission project that their company would be building/developing. Incumbent enrolled transmission providers would include the total transmission project costs that they are funding within their respective rate bases and transmission revenue requirements for recovery in their routine rate processes. For those portions of the project costs that are over and above their cost responsibility, the incumbent enrolled transmission providers would file with FERC for authorization to recover their Transmission Revenue Requirement ("TRR") associated with those project costs to be directly assigned to the beneficiary(ies) responsible for that portion of the cost assignment. The TRR when received by the incumbent developer would be treated as a revenue credit recorded in Account 456, Miscellaneous Revenue in its cost of service to offset the inclusion of other beneficiary(ies) assigned cost in rate base and revenue requirement. In addition to including the TRR for those portions of the project costs that were over and above their cost responsibility, the incumbent enrolled transmission providers would also include any TRR costs allocated to them in their FERC-filed cost of service in support of FERC-approved OATT rates. Enrolled transmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC for authorization to include their allocated TRR costs in the formula rate. See Example 2 provided in Appendix 6 for more detail and accounting treatment.

B. If a non-incumbent developer builds the CEERTS project, it shall file with FERC for authorization to recover its developer costs in the form of a TRR from the incumbent enrolled transmission providers in accordance with their cost responsibilities as determined by the cost allocation methodologies. The incumbent enrolled transmission providers may include those costs allocated to them in their respective wholesale rates (*e.g.*, in FERC-filed cost of service in support of FERC approved OATT rates). Enrolled transmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC to include their allocated TRR costs in the formula rate. See Example 3 provided in Appendix 6 for more detail and accounting treatment.

C. Incumbent enrolled transmission providers with formula-based OATT rates shall be allowed to revise their formula rates to include the intangible asset investment balance as directly assignable transmission function rate base, and amortization expense should be included as transmission function specific expense. Formula-based OATT rates shall be revised by submitting a separate FPA section 205 filing with FERC.

D. Enrolled transmission provider(s) will be responsible for recovering their related local project costs from the beneficiaries allocated such costs through a FPA section 205 filing if the enrolled transmission provider is FERC-jurisdictional or through FERC's declaratory order process if the enrolled transmission provider is non-jurisdictional.

E. Enrolled transmission provider(s) will be responsible for recovering their actual displacement costs, if applicable, through a FPA section 205 filing if the enrolled transmission provider is FERC-jurisdictional or through FERC's declaratory order process for non-jurisdictional enrolled transmission owners. In such filing, the enrolled transmission provider(s) will allocate displacement costs in the same manner as the CEERTS project costs are allocated.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
9.4.6, , 0.1.0, A
Record Narative Name:
Tariff Record ID: 955
Tariff Record Collation Value: 476532 Tariff Record Parent Identifier: 855
Proposed Date: 2015-01-01
Priority Order: 700
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

Neighboring Transmission Planning Region Potential Cost Impacts Not Included in FRCC's CEERTS Cost:

The costs associated with any required upgrades identified through the FRCC's CEERTS project evaluation process identified in section 1.2.9.F for the neighboring transmission planning region will not be included in the CEERTS cost within the FRCC. However, nothing in this Attachment K prevents the beneficiaries or project sponsor of a CEERTS project that causes the need for upgrades in another region from voluntarily negotiating a resolution of the project impacts with the transmission owner(s) in the other region.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
9.4.7, , 0.0.0, A
Record Narative Name:
Tariff Record ID: 960
Tariff Record Collation Value: 476536 Tariff Record Parent Identifier: 855
Proposed Date: 2015-01-01
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier: 658

Allocation of Transmission Rights:

Enrolled transmission providers allocated costs of CEERTS projects shall have priority with regard to any transmission rights associated with such projects, in proportion to their respective share of such costs. Any use of the transmission rights allocated to the Transmission Provider, including use by the Transmission Provider itself, shall be governed by this Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
11.1, , 1.2.0, A
Record Narative Name:
Tariff Record ID: 942
Tariff Record Collation Value: 478487 Tariff Record Parent Identifier: 941
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 648

To be considered in transmission planning, a public policy requirement must be reflected in state, federal, or local law or regulation (including an order of a state, federal, or local agency). If a stakeholder identifies a transmission need that is driven by a public policy requirement, it must submit a written description of the need to the FRCC PC, prior to January 1st of the first year of the biennial regional projects planning cycle, for consideration in regional planning during that planning cycle. To the extent the information is available to the stakeholder, the description of the need should: 1) identify the state, federal, or local law or regulation that contains the public policy requirement; 2) identify the type of entity(ies) in the region to which the public policy requirement applies; 3) identify the subset of entities in the region subject to the public policy requirement that have a transmission need driven by the public policy requirement; 4) describe the type and nature of the transmission service, including the number of megawatts, needed from the enrolled transmission providers by such subset of entities to meet that transmission need. Any stakeholder submitting a potential public policy transmission need to the FRCC PC may, but is not required to, also propose a transmission project(s) to meet such a need along with its description of the need. All submissions will be posted on the FRCC website for public comment and will be reviewed to determine if a public policy requirement is driving a transmission need for which a solution is required. The FRCC PC, under the oversight of the FRCC Board, may seek, on a voluntary basis, additional information from entities identified as having potential needs and then will evaluate the submittals and any additional information to make a decision as to whether a public policy requirement is driving a transmission need for which a solution is required and will post this determination on the FRCC website prior to March 1st of the first year of the biennial regional projects planning cycle, along with an explanation and record of that determination (including a negative determination). If a public policy transmission need is identified for which a solution is required, CEERTS and local projects shall be proposed to address such a need.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Appendix 1, to Attachment K, 2.2.0, A
Record Narative Name:
Tariff Record ID: 882
Tariff Record Collation Value: 478766 Tariff Record Parent Identifier: 249
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

Local Transmission Network Planning Process – Process Description

The Local Transmission Network Planning Process ("Local Process") is performed annually with the Transmission Provider's plan being finalized on or about April 1st of each calendar year. The times shown (in months) for each of the steps contained in the Local Process are target dates that recognize some potential overlapping of the various activities. The Transmission Provider may develop a different timeline where warranted with the concurrence of the Transmission Provider's Customers/Stakeholders. The timelines and dates in this Appendix 1 to Attachment K are to be used as guidelines subject to modification (modified or expedited) as warranted. It is also recognized and understood that under the Transmission Provider's OATT, there are certain FERC mandated timelines that are applied to Transmission Service Requests ("TSRs") and Generator Interconnection Service Requests ("GISRs") that may conflict and be of higher priority than the Local Process. Therefore, Transmission Provider's receipt of TSRs and/or GISRs may require the modification, from time to time, of the timelines described below.
(Proceed to FRCC Regional Planning Process)

Local Transmission Network Planning Process – Process Description Overview:

- The Transmission Provider, which is ultimately responsible for the development of the Transmission Provider's annual 10 Year Expansion Plan, will lead the Local Process on a coordinated basis with the Customers/Stakeholders. This Local Transmission Planning Process will be implemented in such a manner as to ensure the development of the Local Transmission Plan in a timely manner. The Transmission Provider will facilitate each meeting throughout the process. The Transmission Provider will encourage an open dialogue and the sharing of information with Customers/Stakeholders (subject to confidentiality requirements and FERC Standards of Conduct – *note:* the provision for handling of information also applies to all steps of the Local Process) in the development of the Local Transmission Plan.

- Customers/Stakeholders are invited to participate in the Transmission Provider's Local Process.

- The Local Process will comply with the FERC nine principles as well as the provisions below.

- All annual initial kick-off meetings will be open to all Customers/Stakeholders and noticed by the Transmission Provider to all Customers/Stakeholders with sufficient time to arrange for travel planning and attendance (two week minimum). The annual initial kick-off meeting will be a face-to-face meeting; otherwise, with the consent of the

Customers/Stakeholders, meetings may be organized as face-to-face meetings, conference calls, web-ex events, etc., wherein the dialogue and communications will be open, direct, detailed, and consistent with the FERC Standards of Conduct and confidentiality requirements.

- The Customers/Stakeholders may initiate the dispute resolution process at any point in the Local Process where agreement between the Transmission Provider and Customer(s)/Stakeholder(s) cannot be reached.
- The entities generally responsible for undertaking the tasks described below are designated as the TP (Transmission Provider) and/or the S (Customers/Stakeholders).

The study process will include the following steps:

A. Data Submission Requirements (STEP 1 – 3 months)

In order for The Transmission Provider to carry out its responsibility of developing the Transmission Provider's annual 10 Year Expansion Plan and leading the Local Process on a coordinated basis with the Customers/Stakeholders, data submission by the Customer/Stakeholder on a timely manner (on or before January 1st of each year) is essential. As such, the following data submission requirements from Customers/Stakeholders to the Transmission Provider are established. The Customers/Stakeholders will submit data to the Transmission Provider in a format that is compatible with the transmission planning tools in common use by the Transmission Provider. The Transmission Provider will identify the data format to be used by the Customers/Stakeholders for all data submissions, or absent a Transmission Provider identified data format, the Customers/Stakeholders will use their discretion in selection of data format. Examples of data that may be required are:

- Load forecasts, if appropriate:
  - Coincident and non-coincident Peak load forecasts will be provided for the subsequent 11 years, for each summer and winter peak season, with real power and reactive power values for each load serving substation (reflected to the transformer high-side) or delivery Point, as applicable.
- Transmission Delivery Points, if appropriate:

- Delivery Point additions and/or Delivery Point modifications that have not previously been noticed to the Transmission Provider will be communicated by the Customer/Stakeholder to the Transmission Provider via the standard Delivery Point Request letter process.

- Delivery Point additions and/or Delivery Point modifications that have not previously been included in the FRCC Databank Transmission Planning models will be provided by the Customers/Stakeholders to the Transmission Provider via the standard FRCC Project Information Sheet ("PIF") per the attached Transmission Provider provided form and by the Siemens PTI PSS/E IDEV file format, compatible with the Siemens PTI PSS/E version in common use throughout the FRCC Region at that time.

- Network Resource Forecast, if appropriate:

  - Network Resource forecasts will be provided for the subsequent 11 years, for each summer and winter peak season. At a minimum, the following data will be provided: 1. the name of each network resource; 2. the total capacity of each network resource; 3. the net capacity of each resource; 4. the designated network capacity of each resource; 5. the Balancing Authority Area wherein each network resource is interconnected to the transmission grid; 6. the transmission path utilized to deliver the capacity and energy of each network resource to the Transmission Provider's transmission system; 7. the Transmission Provider's point of receipt of each network resource; 8. the contract term of each network resource, if not an owned network resource; and 9. the dispatch order of the entire portfolio of network resources (subject to confidentiality requirements and Standards of Conduct).

- Needs driven by public policy requirements, if appropriate:

  - To be considered in the local transmission network planning process, a public policy requirement must be reflected in state, federal, or local law or regulation (including an order of a state, federal, or local agency). If a stakeholder identifies a transmission need that is driven by a public policy requirement, it must submit a written description of the need to the Transmission Provider, for consideration in local planning during that planning cycle. To the extent the information is available to the stakeholder, the description of the need should:

    1) Identify the state, federal, or local law or regulation that contains the public policy requirement;

    2) Identify the type of entity(ies) in the Transmission Provider's area to which the public policy requirement applies;

    3) Identify the subset of entities in the area subject to the public policy requirement that have a transmission need driven by the public policy requirement;

    4) Describe the type and nature of the transmission service needed from the transmission provider by such subset of entities to meet that

transmission need.

- How, where, and to whom, the data will be submitted to:
  - If hardcopy, the Transmission Provider will provide the mailing address;
  - If faxed, the Transmission Provider will provide the fax number;
  - If e-mailed, the Transmission Provider will provide the e-mail address;
  - If delivered to a password protected FTP site or e-vault, the Transmission Provider will provide the folder for the data, the contact person to be notified of the data delivery, etc. consistent with confidentially requirements and FERC Standards of Conduct.

The Transmission Provider will provide the name and contact details for the Transmission Provider point of contact for data submittal questions.

B. Stakeholder Data Submissions (S) (STEP 1 – con't)

- On or before January 1st of each calendar year, the Customers/Stakeholders will submit the required data (as directed by the Transmission Provider procedures communicated in A. above), plus any additional data that they believe is relevant to the process.

- On or before January 1st of each calendar year, the Customers/Stakeholders will submit to the Transmission Provider the name(s) and contact details for those individuals that will represent them as the point(s) of contact for resolution of any data submittal or study questions/conflicts.

- On or before January 1st of each calendar year, the Customers/Stakeholders will submit the name(s) of those individuals that will represent them during the FRCC Data Bank Transmission Planning Model development process and throughout the Local Process. Name(s), contact details, and their FERC Standards of Conduct status (i.e., Reliability Only, Merchant function, etc.) will be provided. The contact individuals can be changed by the Customers/Stakeholders with notice to Transmission Provider.

- On or before January 1st of each calendar year, the Customers/Stakeholders will submit a written description of a transmission need that a Stakeholder believes is driven by a public policy requirement to the Transmission Provider. Any stakeholder submitting a potential public policy transmission need to the Transmission Provider may, but is not required to, also propose a transmission project(s) to meet such a need along with its description of the need.
  - All submissions will be posted on the Transmission Provider's website for public comment and will be reviewed to determine if a public policy requirement is

driving a transmission need for which a solution is required.

- The Transmission Provider may seek, on a voluntary basis, additional information from entities identified as having potential needs and then will evaluate the submittals and any additional information to make a decision as to whether a public policy requirement is driving a transmission need for which a solution is required and will post this determination on the Transmission Provider's website prior to April 1st of the local transmission network planning cycle, along with an explanation and record of that determination (including a negative determination). If a public policy transmission need is identified for which a solution is required local projects shall be proposed to address such a need.

C. FRCC Data Bank Transmission Planning Model Development Process (TP/S) (STEP 2 – 2 months)

- The FRCC Regional Data Bank Development Process will control the model development schedule and work product as established by the applicable FRCC Working Group.

D. Kick-off for Transmission Provider's Local Transmission Network Planning Process (STEP 2 – con't - 1 month)

- The Transmission Provider will, approximately two (2) weeks prior to the second quarter initial kick-off meeting (or other date, if Transmission Provider and Customers/Stakeholders agree), communicate via e-mail with all Customers/Stakeholders the schedule/coordination details of the Transmission Provider's Local Process kick-off meeting(s). Customer/Stakeholder shall provide to Transmission Provider a confirmation of their intent to participate in the initial kick-off meeting at least three (3) days prior to such meeting. (TP)

- The Transmission Provider will, in advance of the Kick-off meeting(s), with sufficient time for Customer/Stakeholder review, provide to the Customers/Stakeholders a proposed study schedule, the NERC and FRCC Reliability Standards that will apply to the study, and/or guidelines that will apply to the study and Transmission Provider developed criteria that will apply to the study, including public policy requirements. (TP)

- The initial Kick-off meeting in the second quarter of the calendar year will begin the Transmission Provider's Local Process. The Transmission Provider will review and validate the input data assumptions received from each Customer/Stakeholder, discuss the proposed study schedule, and discuss the study requirements, which will include, but not be limited to, the following:

    - The methodologies that will be used to carry out the study (TP/S)

    - The specific software programs that will be utilized to perform the analysis (TP)

- The Years to study (TP/S)
- The load levels to be studied (e.g., peak, shoulder and light loads) (TP/S)
- The criteria for determining transmission contingencies for the analysis (i.e. methods, areas, zones, voltages, generators, etc.) (TP/S)
- The Individual company criteria (i.e., thermal, voltage, stability and short circuit) by which the study results will be measured (TP/S)
- The NERC reliability standards by which the study results will be measured (TP/S)
- The FRCC reliability standards and requirements by which the study results will be measured (TP/S)
- Customer/Stakeholder proposed study scenarios for Transmission Provider consideration in the analysis (TP/S)
- Potential solutions proposed by Stakeholders to identified transmission needs driven by public policy requirements (TP/S)

- The kick-off process will be complete when the schedule, standards, criteria, rules, tools, methods and Customer/Stakeholder participation are finalized for the study process to (described below) begin. (TP/S)

E. Case Development (TP) (STEP 3 – 1 month)

- Utilizing all of the data received from the Customers/Stakeholders during the data submission stage and the standards, criteria, rules, tools, and methods determined in the kick-off meeting(s), the Transmission Provider will develop the base case models to be used for the study. These models will be developed in the Siemens PTI PSS/E file format, compatible with the Siemens PTI PSS/E version in use by the Transmission Provider.

- Utilizing all of the data received from the Customers/Stakeholders during the data submission stage and the standards, criteria, rules, tools, and methods determine in the kick-off meeting, the Transmission Provider will develop the change case models to be used for the study. These models will be developed in the Siemens PTI PSS/E file format, compatible with the Siemens PTI PSS/E version in use by the Transmission Provider.

- The Transmission Provider will electronically post and provide notice to the Customers/Stakeholders of the posting of the base case models, the change case models and/or the IDEV files.

F. Perform System Analysis (STEP 4 - 1 to 2 months)

- The Transmission Provider will perform the study analyses (verification that thermal, voltage, stability and short circuit values meet all planning criteria) on the local transmission plan (including potential solutions to identified transmission needs driven by public policy requirements) and produce the initial unfiltered, un-processed input data, output data, and files. (TP)

- The Transmission Provider will electronically post and provide notice to the Customers/Stakeholders of the posting of the initial unfiltered, un-processed input data, output data, and files. (TP/S)

G. Assessment and Problem Identification (STEP 5 - 1 month)

- The Transmission Provider will evaluate at the local level the initial unfiltered, un-processed output data to identify any problems / issues for further investigation. The Transmission Provider will document, electronically post, and provide notice to the Customers/Stakeholders if there is an impact to them of the posting of the evaluation results documentation associated with the impact to the Customer/Stakeholder. (TP/S)

- The Customers/Stakeholders may perform their own additional sensitivities. (S)

H. Mitigation / Alternative Development (STEP 6 - 1 to 2 months)

- The Transmission Provider will identify potential solutions / mitigation proposals, including solutions to identified transmission needs driven by public policy requirements, to address problems / issues. (TP)

- The Transmission Provider will document, electronically post, and provide notice to the Customers/Stakeholders of the posting of the identified potential solutions / mitigation proposals to address problems / issues related to the impacted Customer(s)/Stakeholder(s).

- The Customers/Stakeholders may provide alternative potential solutions / mitigation proposals, including alternative solutions to identified transmission needs driven by public policy requirements, for the Transmission Provider to consider. Such information shall be provided in IDEV format and posted. (TP/S)

- The Transmission Provider will determine the effectiveness of the potential solutions through additional studies (thermal, voltage, stability and short circuit). The Transmission Provider may modify the potential solutions, as necessary, such that required study criteria are met. (TP)

- The Transmission Provider will identify feasibility, timing and cost-effectiveness of proposed solutions that meet the study criteria. (TP/S)

I. Selection of Preferred Transmission Plan (STEP 6 con't - 1 to 2 months)

- The Transmission Provider, in consultation with the Customers/Stakeholders, will compare the alternatives and select the preferred solution / mitigation alternatives based on feasibility, timing and cost effectiveness that provide a reliable and cost-effective transmission solution, taking into account neighboring transmission providers' transmission plans. (TP/S)

- In case of Transmission Provider and Customer/Stakeholder dispute, the dispute resolution process described in section 6.1 will be utilized. (TP/S)

J. Send Selected Local Transmission Network Plan Results (Transmission Provider's Ten Year Expansion Plan) to the FRCC (STEPS 7 & 8 - 1 to 2 months)

- The Transmission Provider will submit the Transmission Provider's proposed local transmission network plan results (the Transmission Provider's 10 Year Expansion Plan) to the FRCC for posting with other transmission plans as the FRCC's initial regional transmission expansion plan (reference the *Initial Plans* on the FRCC website), along with an indication whether there are any pending disagreements regarding the Plan (and if there are, will elicit from the dissenting entity(ies), and provide, a minority report regarding such differences of opinion). The Transmission Provider's 10 Year Expansion Plan will include all transmission system projects without differentiation between bulk transmission system projects and lower voltage transmission system projects (i.e. all projects 69 kV and above). This Transmission Provider submittal to the FRCC will be made on or about April 1 and will become part of the initial FRCC regional transmission plan. (TP)

- The *FRCC Regional Planning Process* will now start and the FRCC Regional Planning Process rules and guidelines will now control the transmission planning process. (TP/S)

- Following completion of the Transmission Provider's submission of the local transmission network plan results (the Transmission Provider's 10 Year Expansion Plan) to the FRCC, the Transmission Provider will, either directly or through the FRCC project status reporting process, make available to the Customers/Stakeholders project descriptions, project scheduled in-service dates, project status, etc. for all projects. This information should be updated no less often than quarterly. (TP)

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Appendix 2, to Attachment K, 2.1.0, A
Record Narative Name:
Tariff Record ID: 883
Tariff Record Collation Value: 479882 Tariff Record Parent Identifier: 249
Proposed Date: 2015-01-01
Priority Order: 700
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

FRCC Quorum and Voting Sectors

Note: The below descriptions of the FRCC's Quorum and Voting provisions were extracted from the FRCC *Rules of Procedure for FRCC Standing Committees.* The FRCC PC is one of the Standing Committees within the FRCC.

A. Quorum

Representation at any meeting of the standing committees of 60% or more of the total voting strength of the Standing Committee, shall constitute a quorum for the transaction of business at such meeting; provided, however, that action on matters dealing with the scope or funding of Member Services shall require sixty percent (60%) or more of the total voting strength of members of the Standing Committee representing Voting Members that are Services Members; and provided further that a quorum shall require that at least three (3) Sectors are represented, all three of which shall be Sectors, a majority of the members of which are Services Members in the case of a quorum for action on matters governing Member Services.

If a quorum is not present at any meeting of the standing committees, then no actions may be taken for the purpose of voting. The representatives present may decide to have discussions concerning agenda items as long as voting is not called.

B. Voting

Voting is by Sector. Each voting representative present at a meeting is assigned a vote equal to the voting strength of their Sector, as provided in this section, divided by the number of voting representatives present in that Sector, except that no voting representative present at a meeting shall have more than one (1) vote, except an Investor Owned Utility Sector voting representative who may have up to 1.167 votes. Action by the Standing Committee shall require an affirmative vote equal to or greater than sixty percent (60%) of the total voting strength of the Standing Committee.

Sector Votes

(1) Suppliers Sector	2.5 Votes
(2) Non-Investor Owned Utility Wholesale Sector	2 Votes
(3) Load Serving Entity Sector	
Municipal	0.5 Vote
Cooperative	0.5 Vote
(4) Generating Load Serving Entity Sector	3.0 Votes
(5) Investor Owned Utility Sector	3.5 Votes
(6) General	1 Vote
Total	13 Votes

Record Content Description, Tariff Record Title, Record Version Number, Option Code:

Appendix 3, to Attachment K, 1.2.0, A
Record Narative Name:
Tariff Record ID: 943
Tariff Record Collation Value: 480440 Tariff Record Parent Identifier: 249
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

Project Developer Qualification Criteria

1. Demonstration that the project developer is technically, and financially capable of (i) completing the CEERTS project in a timely and competent manner; and (ii) operating and maintaining the CEERTS facilities consistent with Good Utility Practice and applicable reliability criteria for the life of the project. To support this demonstration, the following information should be provided/shown:

   A. Project developer's current and expected capability to finance, or arrange financing for the transmission facilities:

      1. Evidence of its demonstrated experience financing or arranging financing for transmission facilities, including a description of such projects (not to exceed ten) over the previous ten years, the capital costs and financing structure of such projects, a description of any financing obtained for these projects through any approved rates, the financing closing date of such project, and whether any of the projects are in default;

      2. Its audited financial statements from the most recent three years and its most recent quarterly financial statement, or equivalent information;

      3. Current credit ratings from Moody's Investor Services and Standard & Poors, if available;

      4. A summary of any history of bankruptcy, dissolution, merger, or acquisition of the project developer or any predecessors in interest for the current calendar year and the five calendar years immediately preceding its submission of information related to affiliated entities;

      5. A summary of outstanding liens against the developer(s); and

      6. Such other evidence that demonstrates its current and expected capability to finance a CEERTS project.

      The project developer must identify the portions of this financial data that would need to be treated as confidential information in accordance with the FRCC confidentiality practices and subject to disclosure only to those that have signed a confidentiality agreement.

   B. Total dollar amount of CEERTS estimated project(s) cost up to which the project developer wants to be deemed qualified.

C. A discussion of the project developer's business practices that demonstrate that its business practices are consistent with Good Utility Practices for proper licensing, designing, right-of-way acquisition, constructing, operating and maintaining transmission facilities that will become part of the regional transmission grid. The project developer shall also provide the following information for the current calendar year and the previous five calendar years:

1. A summary of any violations of law by the project developer found by federal or state courts, federal regulatory agencies, state public utility commissions, other regulatory agencies, or attorneys general; and

2. A summary of any instances in which the project developer is currently under investigation or is a defendant in a proceeding involving an attorney general or any state or federal regulatory agency, for violation of any laws, including regulatory requirements.

D. Technical and engineering qualifications and experience;

E. Past history of meeting transmission project schedules;

F. Past history regarding providing construction and maintenance of transmission facilities and/or contracting for the construction and maintenance of transmission facilities;

G. Capability to adhere to standardized construction, maintenance and operating practices;

H. Plans for compliance with all applicable reliability standards:

I. Planning standards that will be used to develop the project: and

J. Plans to obtain the appropriate NERC certifications.

2. An attestation from an officer of the project developer stating that the information that is being submitted is true and that the project developer will comply with the provisions identified in the qualification data submittal, and will submit a biennial (or more often if the information provided has materially changed) update of the information submitted, accompanied by an attestation from an officer of the project developer that the previously submitted information remains correct and has not materially changed since the last attestation, with such attestation to be submitted biennially while that transmission developer has a transmission project under consideration in the FRCC Regional Planning Process, under construction in the FRCC region or in-service within the FRCC region.

3. For joint ventures, partnerships, or other multiple-party developer arrangements, the qualification criteria above will be applied to the designated lead entity, which will be responsible for meeting the qualification criteria. Sharing of such responsibilities with other entities may be achieved contractually between the designated lead entity and its partners.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Appendix 4, to Attachment K, 1.2.0, A
Record Narative Name:
Tariff Record ID: 944
Tariff Record Collation Value: 480719 Tariff Record Parent Identifier: 249
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

Examples of CEERTS Cost Allocation Methodology

Example 1: Reliability/Economic Project

- CEERTS project where Enrolled Transmission Providers A, B and C all receive benefits from the project.
- The project developer is a non-incumbent developer

Assumptions:

- Estimated CEERTS Project Cost = $401M:
  - Estimated Developer Cost = $400M
  - Total Estimated Related Local Project Costs = $1M
- Total Estimated Avoided Project Cost Benefit = $500M:
  - Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $300M
  - Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $200M
  - Enrolled Transmission Provider C Estimated Avoided Project Cost Benefit = $0
- Total Estimated Alternative Project Cost Benefit = $0M
- Total Estimated Transmission Line Loss Value Benefit = $14M:
  - Enrolled Transmission Provider A Estimated Transmission Line Loss Value Benefit = $4M
  - Enrolled Transmission Provider B Estimated Transmission Line Loss Value Benefit = $5M
  - Enrolled Transmission Provider C Estimated Transmission Line Loss Value Benefit = $5M

Benefit to Cost Ratio:

- ("Total Estimated Avoided Project Cost Benefit" ($500M) plus "Total Estimated Alternative Project Cost Benefit" ($0M) plus "Total Estimated Transmission Line Loss Value Benefit" ($14M)) divided by Estimated CEERTS Project Cost ($401M) = 1.28, therefore this CEERTS project passes the benefit to cost ratio threshold.

CEERTS Project Cost Allocation:

- (Percentages in example are rounded to nearest whole percentage)
  - Enrolled Transmission Provider A = ($300M + $4) ÷ $514M = 59%
  - Enrolled Transmission Provider B = ($200M + $5M) ÷ $514M) = 40%
  - Enrolled Transmission Provider C = ($0 + $5M) ÷ $514M) = 1%

Example 2: Reliability/Economic Project

- CEERTS project where Enrolled Transmission Providers A & B each receive avoided cost benefits from the project
- There are no transmission loss benefits
- The project developer is a non-incumbent developer

Assumptions:

- Estimated CEERTS Project Cost = $400 M:
  - Estimated Developer Cost = $400 M
- Total Estimated Avoided Project Cost Benefit = $300 M:
  - Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $100 M
  - Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $200 M
- Total Estimated Alternative Project Cost Benefit = $0M

Benefit to Cost Ratio:

- "Total Estimated Avoided Project Cost Benefit" ($300 M) divided by Estimated CEERTS Project Cost ($400 M) = 0.75, therefore this CEERTS project does not pass the benefit to cost ratio threshold.

CEERTS Project Cost Allocation:

- N/A

Example 3: Public Policy Project

- CEERTS project where LSEs within Enrolled Transmission Providers A, B and C each receive benefits from the project
- The project developer is a non-incumbent developer

Assumptions:

- Public policy CEERTS project enables access to a total of 600 MW of public policy resources
- Public policy CEERTS project enables LSEs within Enrolled Transmission Providers A, B and C to access the public policy resources:
  - Enrolled Transmission Provider A = 100 MWs
  - Enrolled Transmission Provider B = 200 MWs
  - Enrolled Transmission Provider C = 300 MWs

CEERTS Project Cost Allocation:

- Enrolled Transmission Provider A = (100 MW / 600 MW) = 17%
- Enrolled Transmission Provider B = (200 MW / 600 MW) = 33%
- Enrolled Transmission Provider C = (300 MW / 600 MW) = 50%

Example 4: Newly-Proposed CEERTS Project Displacing a Previously-Approved CEERTS Project

- Previously-approved CEERTS project was estimated to provide LSEs within Enrolled Transmission Provider A and B benefits
- Newly-proposed CEERTS project would displace the previously-approved CEERTS project as well as being estimated to provide LSEs within Enrolled Transmission C benefits from the newly-proposed CEERTS project
- The newly-proposed CEERTS project would displace the previously-approved CEERTS project

<u>Previously-Approved CEERTS Project:</u>

Assumptions:

- Estimated Previously-Approved CEERTS Project Cost = $75M
- Total Estimated Previously-Approved CEERTS Project Avoided Project Cost Benefit =

$100M

- Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $50M
- Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $50M

Previously-Approved CEERTS Project Cost Allocation:

- (Percentages in example are rounded to nearest whole percentage)
  - Enrolled Transmission Provider A = ($50M / $100M) = 50%
  - Enrolled Transmission Provider B = ($50M / $100M) = 50%

<u>Previously-Approved CEERTS Project Displaced by a Newly-Proposed CEERTS Project:</u>

Assumptions:

- Estimated Newly-Proposed CEERTS Project = $100M

- Total Estimated Newly-Proposed CEERTS Avoided Project Cost Benefit = $125M
  - Total Estimated Previously-Approved CEERTS Project Cost Benefit = $75M
  - Enrolled Transmission Provider C Estimated Avoided Project Cost Benefit = $50M

Newly-Proposed CEERTS Project Cost Allocation:

- (Percentages in example are rounded to nearest whole percentage)
  - Previously-Approved CEERTS Project Enrolled Transmission Providers (A & B) = ($75M / $125) = 60%
    - This 60% of the cost responsibility would be allocated to Enrolled Transmission Providers A & B:
      - Enrolled Transmission Provider A = 60% * 50% = 30%

- Enrolled Transmission Provider B = 60% * 50% = 30%

– Enrolled Transmission Provider C = ($50M / $125M) = 40%

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Appendix 6, to Attachment K, 0.2.0, A
Record Narative Name:
Tariff Record ID: 957
Tariff Record Collation Value: 480823 Tariff Record Parent Identifier: 249
Proposed Date: 2015-01-01
Priority Order: 800
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier: 658

Appendix 6 to Attachment K
Examples of Cost Recovery Provisions
Page 1 of 3

Example 1: per 9.4.5.A (1)

- CEERTS project where Companies A & B are incumbent enrolled transmission providers and each receive benefits from the project
- Company A is the project developer
- Company B makes a FERC-approved CIAC payment to Company A for its allocated cost and records an intangible asset in its rate base to be amortized
- Company A records CIAC as a reduction to transmission plant in service
- Company B CIAC payment is grossed-up for income taxes

Example 2: per 9.4.5.A (2)

- CEERTS project where Companies A & B are incumbent enrolled transmission providers and each receive benefits from the project
- Company A is the project developer and funds the entire project
- Company A files with FERC to recover its transmission revenue requirement from Company B over 30 years
- Company A reduces its transmission revenue requirements
- Company B increases its transmission revenue requirements
- Assume capital replacements are $90 million over the 30-year period
- Assume operating and maintenance expense (O&M) is $150 million over the 30-year period
- Assume total pretax return on rate base to Company A of $350 million (pretax ROR of 12%)
- Total revenue requirement due to Company A is capital, O&M, and return on capital

Example 3: per 9.4.5.B

- CEERTS project where Companies A & B each receive benefits from the project

- Company C is a non-incumbent and the project developer and funds the entire project
- Company C files with FERC to recover its transmission revenue requirement from Company A & B over 20 years
- Company A & B increase their transmission revenue requirements
- Assume capital replacements are $90 million over the 30 year-period
- Assume operating and maintenance expense (O&M) is $150 million over the 30-year period
- Assume total pretax return on rate base to Company C of $900 million (pretax ROR of 12%)
- Total revenue requirement due to Company C is capital, O&M, and return on capital

Document Content(s)