September 14, 2007

TO: FERC Staff, Transmission Customers, and other Stakeholders

FROM: Duke Energy Carolinas, LLC
Progress Energy Carolinas, Inc.

RE: Draft Attachment K

Attached is the draft "Attachment K" of both Duke Energy Carolinas, LLC (Duke) and Progress Energy Carolinas, Inc. (Progress), which draft has been reviewed and endorsed by the Oversight/Steering Committee of the North Carolina Transmission Planning Collaborative (NCTPC).

In both Order No. 890 and the August 2, 2007 Transmission Planning Process Staff White Paper, the Commission indicated that Transmission Providers could use a combination of tariff language in Attachment K, and references to planning manuals on their websites, to satisfy their planning obligations under Order No. 890. The Draft Attachment K adopts such an approach, which provides the NCTPC flexibility, by referring to several NCTPC documents that are posted on the NCTPC Website (NCTPC Planning Documents). The Transmission Providers both will provide a link to the NCTPC Website on their OASIS sites. For the convenience of FERC Staff, the NCTPC Planning Documents that are referenced are all being attached to this Draft Attachment K, although the NCTPC Planning Documents will not be a part of the Tariffs of Duke or Progress. The attached NCTPC Planning Documents are: *Participation Agreement, North Carolina Transmission Planning Collaborative Process, Scope - Oversight/Steering Committee, Scope - Planning Working Group, Transmission Advisory Group - Scope, NCTPC Transmission Cost Allocation Whitepaper*.

Note that the Draft Attachment K remains a work in progress. There are certain matters that are addressed by the existing NCTPC Process, but such matters must be reevaluated as a result of Order No. 890. That reevaluation process has not been completed by the NCTPC, but is expected to be complete by December 7, 2007. Also, the Transmission Advisory Group of the NCTPC, which is open to all stakeholders, will be provided the opportunity to comment. The draft will first be presented to that group on September 17, 2007, in addition to being presented at FERC's October technical conference. Additionally, work has recently commenced on a new Southeast Inter-Regional Participation Process and it is expected that the final Attachment K will reflect future developments relating to that group. The IRPP's whitepaper is attached to this submission.

Duke, Progress, and the NCTPC look forward to working with FERC Staff and stakeholders in continuing to develop this Attachment K in preparation for its filing on December 7, 2007.

[DRAFT ATTACHMENT K]

1. INTRODUCTION

Duke Energy Carolinas, LLC (Duke) and Progress Energy Carolinas, Inc. (Progress), Transmission Providers with transmission facilities located in the states of North Carolina and South Carolina, ensure that their entire Transmission Systems (i.e., both the portions located in North Carolina and the portions located in South Carolina) are planned in accordance with the requirements imposed by Order No. 890 through the process developed by the North Carolina Transmission Planning Collaborative Process (NCTPC Process). The NCTPC was formed by the following load serving entities (LSEs) in the State of North Carolina: Duke, Progress, ElectriCities of North Carolina (ElectriCities), and the North Carolina Electric Membership Corporation (NCEMC) (collectively, NCTPC Participants or Participants).

In addition to engaging in regional planning through the NCTPC Process, as discussed in Section 10, the Transmission Providers engage in "inter-regional" study and planning activities with transmission providers located outside their Control Areas.

2. NCTPC PROCESS OVERVIEW INCLUDING THE PROCESS FOR CONSULTING WITH CUSTOMERS

The NCTPC will annually develop a single, coordinated transmission plan (Collaborative Transmission Plan) that appropriately balances costs, benefits, and risks associated with the use of transmission, generation, and demand-side resources to meet the needs of LSEs as well as other Transmission Customers under this Tariff.

2.1 The *North Carolina Load Serving Entities Transmission Planning Participation Agreement* (*Participation Agreement*) governs the NCTPC and the NCTPC Process. The *Participation Agreement* is located on the NCTPC Website (http://www.nctpc.org/nctpc/).

2.2 The NCTPC Process is summarized in a document entitled *North Carolina Transmission Planning Collaborative Process* that is located on the NCTPC Website.

2.3 Participation in the NCTPC

2.3.1 Pursuant to the *Participation Agreement*, the NCTPC has four components: the Oversight/Steering Committee (OSC), the Planning Working Group (PWG), the Transmission Advisory Group (TAG), and the Independent Third Party (ITP).

2.3.2 Eligibility for participation in the four NCTPC components is as follows:

2.3.2.1 The appointment of OSC members by the NCTPC Participants is governed by the *Participation Agreement*. The ITP is an *ex officio* member of the committee. The qualifications required to serve on the OSC are set forth in a document entitled *Scope* -

Oversight/Steering Committee that is located on the NCTPC Website.

2.3.2.2 The appointment of PWG members by the NCTPC Participants is governed by the *Participation Agreement*. The ITP also has a representative on the PWG. The qualifications required to serve on the PWG are set forth in a document entitled *Scope - Planning Working Group* that is located on the NCTPC Website.

2.3.2.3 TAG membership is open to all persons interested in the development of a coordinated transmission expansion plan across the respective service territories of the NCTPC Participants in North Carolina and South Carolina.

2.3.2.4 The Independent Third Party (ITP) is selected by the OSC. The ITP must have qualifications similar to OSC and PWG members.

2.4 Responsibilities and Decision-making of NCTPC Components

The responsibilities of the components within the NCTPC are determined by the *Participation Agreement* and/or the OSC. Decision-making likewise is established in the *Participation Agreement*, or by policies established by the OSC.

2.4.1 Oversight/Steering Committee

2.4.1.1 The OSC is responsible for overseeing and directing all the activities associated with this NCTPC Process. A list of the OSC's responsibilities is found in *Scope - Oversight/Steering Committee.*

2.4.1.2 OSC decision-making is governed by the *Participation Agreement.*

2.4.1.3 Officers of the OSC are selected in the manner set forth in the *Participation Agreement.*

2.4.2 Planning Working Group

2.4.2.1 The PWG is responsible for developing and performing the appropriate simulation studies to evaluate the transmission conditions in the Participants' service territories and recommend a coordinated solution for the various transmission limitations identified in the studies. A list of the PWG's responsibilities is found in *Scope - Planning Working Group.*

2.4.2.2 PWG decision-making is governed by the *Participation Agreement.*

2.4.2.3 Officers of the PWG are selected in the manner set forth in the *Participation Agreement.*

2.4.3 Transmission Advisory Group

2.4.3.1 The purpose of the TAG is to provide advice and recommendations to the Participants to aid in the development of an annual Collaborative Transmission Plan. Through the TAG, all stakeholders with an interest in the Duke and/or Progress transmission planning have an opportunity to provide input. A list of the TAG's responsibilities is found in *Transmission Advisory Group - Scope* - that is located on the NCTPC Website.

2.4.3.2 The TAG meetings are open to all entities, including network, point-to-point, and interconnection customers under this Tariff.

2.4.3.3 TAG decision-making is by consensus. The ITP will chair the TAG meetings and serve as a facilitator for the group.

2.4.4 Independent Third Party

2.4.4.1 The ITP facilitates the overall NCTPC Process.

2.4.4.2 A list of the ITP's primary responsibilities is found in *Scope - Planning Working Group.*

2.4.4.3 The ITP also provides the leadership role in developing the Enhanced Transmission Access Planning (ETAP) Process, subject to the oversight of the OSC.

2.4.4.4 The ITP maintains the NCTPC Website.

2.4.4.5 The ITP's role in decision-making varies based on which group s/he is participating.

2.5 Participation of State Regulators

State regulators, including state-sanctioned entities representing the public, may fully participate in the TAG meetings and provide comments and recommendations on various elements of the NCTPC Process in the TAG discussions. State regulators may receive periodic status updates and the progress reports on the NCTPC Process.

3. NOTICE PROCEDURES, MEETINGS, AND PLANNING-RELATED COMMUNICATIONS

All information regarding transmission planning meetings and communications are located on the NCTPC Website.

3.1 Notice

3.1.1 Notice of all meetings of a component (TAG, PWG, OSC) will be by email to such component.

3.1.2 All TAG meeting notices and agendas will be posted on the NCTPC Website.

3.1.3 Information about signing up to be a TAG member and to receive email communications directed to TAG members is posted on the NCTPC Website.

3.1.4 The OSC will publish highlights of its meetings on the NCTPC Website.

3.2 Location

3.2.1 The location of an OSC or PWG meeting will be determined by the component.

3.2.2 The location of a TAG meeting will be determined by the OSC.

3.2.3 Conference call dial-in technology will be available for meetings upon request.

3.3 Meeting Protocols

3.3.1 OSC

3.3.1.1 The OSC chair schedules meetings, provides notice, ensures that meeting minutes are taken, develops the agenda, chairs the meetings.

3.3.1.2 The OSC generally will meet at least monthly, and more frequently as necessary.

3.3.1.3 OSC meetings are open to the OSC members (including the ITP), their alternates, PWG members, and, if approved, guests.

3.3.2 PWG

3.3.2.1 The PWG chair schedules meetings, provides notice, ensures that meeting minutes are taken, develops the agenda, and chairs the meetings.

3.3.2.2 The PWG generally meets at least monthly, and more frequently as necessary.

3.3.2.3 PWG meetings are open to the PWG members, the ITP, the OSC (and their alternates), and, if approved, guests.

3.3.3 TAG

3.3.3.1 TAG meetings are chaired and facilitated by the ITP.

3.3.3.2 The TAG generally meets four times a year.

3.3.3.3 Meetings of the TAG are open to all parties interested in the development of a coordinated transmission plan across the respective service territories of the Participants. There are no restrictions on the number of people attending TAG meetings from any organization.

3.3.3.4 A yearly meeting and activity schedule is proposed, discussed with, and provided to TAG members annually.

4. DESCRIPTION OF THE METHODOLOGY, CRITERIA, AND PROCESSES USED TO DEVELOP TRANSMISSION PLANS

The NCTPC Process is a coordinated regional planning process that includes both a "Reliability Planning" and an "Enhanced Transmission Access Planning" (ETAP) process, both of which ultimately result in the development of a Collaborative Transmission Plan. The entire, iterative process ultimately results in a single Collaborative Transmission Plan that appropriately balances the costs, benefits and risks associated with the use of transmission, generation, and demand-side resources.

4.1 Overview of Reliability Planning Process

The Reliability Planning Process addresses transmission upgrades needed to maintain reliability and to integrate new generation resources and/or loads. The Reliability Planning Process includes a base reliability study (base case) that evaluates each Transmission System's ability to meet projected load with a defined set of resources as well as the needs of firm point-to-point customers, whose needs are reflected in their transmission contracts and reservations. A resource supply analysis also is conducted to evaluate transmission system impacts for other potential resource supply options to meet future load requirements. The final results of the Reliability Planning Process include summaries of the estimated costs and schedules to provide any transmission upgrades and/or additions needed to maintain a sufficient level of reliability necessary to serve customers.

4.2 Overview of Enhanced Transmission Access Planning Process

4.2.1 The ETAP Process is the economic planning process that allows the TAG to propose economic upgrades to be studied as part of the transmission planning process. The ETAP Process evaluates the means to increase transmission access to potential supply resources inside and outside the Control Areas of the Transmission Providers. This economic analysis provides the opportunity to study what transmission upgrades would be required to reliably integrate new resources. In addition, this economic analysis would include, if requested, the evaluation of Regional Economic Transmission Paths (RETPs) that would facilitate potential regional point-to-point economic transactions. RETPs are described in more detail below and in the document entitled *NCTPC Transmission Cost Allocation Whitepaper* on the NCTPC Website.

4.2.2 The ETAP Process begins with the NCTPC Participants and TAG members proposing scenarios and interfaces to be studied. The information required and the form necessary to submit a request as well as the submittal deadline is reviewed and discussed with the TAG at the beginning of the annual planning cycle. The form is posted on the NCTPC Website.

4.2.3 The proposed scenarios and interfaces to be studied, including any Regional Economic Transmission Paths (RETPs), are compiled by the PWG. After consultation with the TAG, the PWG develops a means to allow the clustering or batching of requests for economic planning studies so that the PWG can perform the studies in the most efficient manner. The PWG prepares a recommendation for the OSC on the proposed studies to be performed. The OSC will evaluate the PWG recommendation to determine which ones will be included for analysis in the current planning cycle. **[Sections 4.2.2 and 4.2.3 reflect the current NCTPC Process and are being reevaluated in light of Order No. 890.]**

4.2.4 RETPs

4.2.4.1 As part of the ETAP, TAG members may propose that a particular RETP be studied. An RETP would ensure that Point-to Point Transmission Service can be provided over the Duke and/or Progress systems. TAG members will be permitted to propose that RETPs be created. The costs of the projects necessary to create such RETPs will be subject to the "requestor pays" cost allocation methodology described *infra*. The creation of an RETP would permit energy to be transferred on a Point-to Point basis from an interface (or a Point of Receipt) on one Transmission Provider's system to an interface (or a Point of Delivery) on another Transmission Provider's system for a specific period of time. The TAG will identify RETPs that they would like studied. There would be a need for an Initial Study of an RETP ("Initial RETP Study"). If a proposed RETP would be solely contained within the NCTPC, then the NCTPC process would be used to address the RETP. However, if a proposed RETP would impact transmission providers outside the NCTPC, there will be a need to coordinate such an initial study with other transmission providers.

4.2.4.2 If an Initial RETP Study is performed, it would identify any transmission system problems/limitations related to the

Transmission Providers along the RETP providing Point-to Point Transmission Service and would identify the transmission solutions/upgrades that would be needed to accommodate the RETP. An RETP would be evaluated in the Initial RETP Study as if it was a request for Point-to Point Transmission Service from a source control area (Point of Receipt) to a sink control area (Point of Delivery) over a specific period of time (the stakeholders requesting the study would determine the time period), but it will not be considered to be a request that is in the transmission queue. The Point of Receipt and Point of Delivery can be interfaces.

4.2.4.3 The Initial RETP Study would only provide preliminary information on the projected cost and scope of the facilities that would be needed to create the RETP, and the time it would take to complete the RETP. In the Initial RETP Study, each Transmission Provider along the RETP would identify the estimated costs for any upgrades necessary to provide service. If the RETP was totally contained within the NCTPC, then the following process would be used to move the RETP through the study to potential project commitment phases. Once the Initial RETP Study is complete, a determination would be made as to whether there is sufficient interest in the project to move the RETP from the “initial study” mode to the establishment of an “Open Season” for the RETP. The Open Season will have a similar impact to someone queuing a Point-to Point Transmission Service request for the entire proposed MW of the RETP from the source control area to the sink control area for the relevant time period. During this Open Season all potential Transmission Customers would have a 30 to 60-day window to put in their request to subscribe to all or a portion of the MW of service being made available along the RETP. Through the Open Season process, which will be iterative, if the RETP is fully subscribed, it would move forward to a Facilities Study stage. After such stage, if it remained fully subscribed, the RETP would be included in the Collaborative Transmission Plan (and/or a supplement to such Plan). If an RETP encompasses Transmission Providers outside the NCTPC, the impacted Transmission Providers will try and work individually and through applicable stakeholder forums to perform the necessary studies and develop the processes that would be used to move from a study of a RETP to actual transmission reservations that would be needed to support the RETP. The above study and Open Season concepts could be used by these larger inter-regional transmission provider groups.

4.2.5 The final results of the ETAP Process include the estimated costs and schedules to provide the increased transmission capabilities. The enhanced transmission access study results are reviewed and discussed with the TAG.

4.3 Overview of the Steps in the Planning Processes

4.3.1 Each year, the OSC will initiate the process to develop the annual Collaborative Transmission Plan.

4.3.2 The OSC will provide notice of the commencement of the process to develop the annual Collaborative Transmission Plan via e-mail to the TAG and posts a notice on the NCTPC Website.

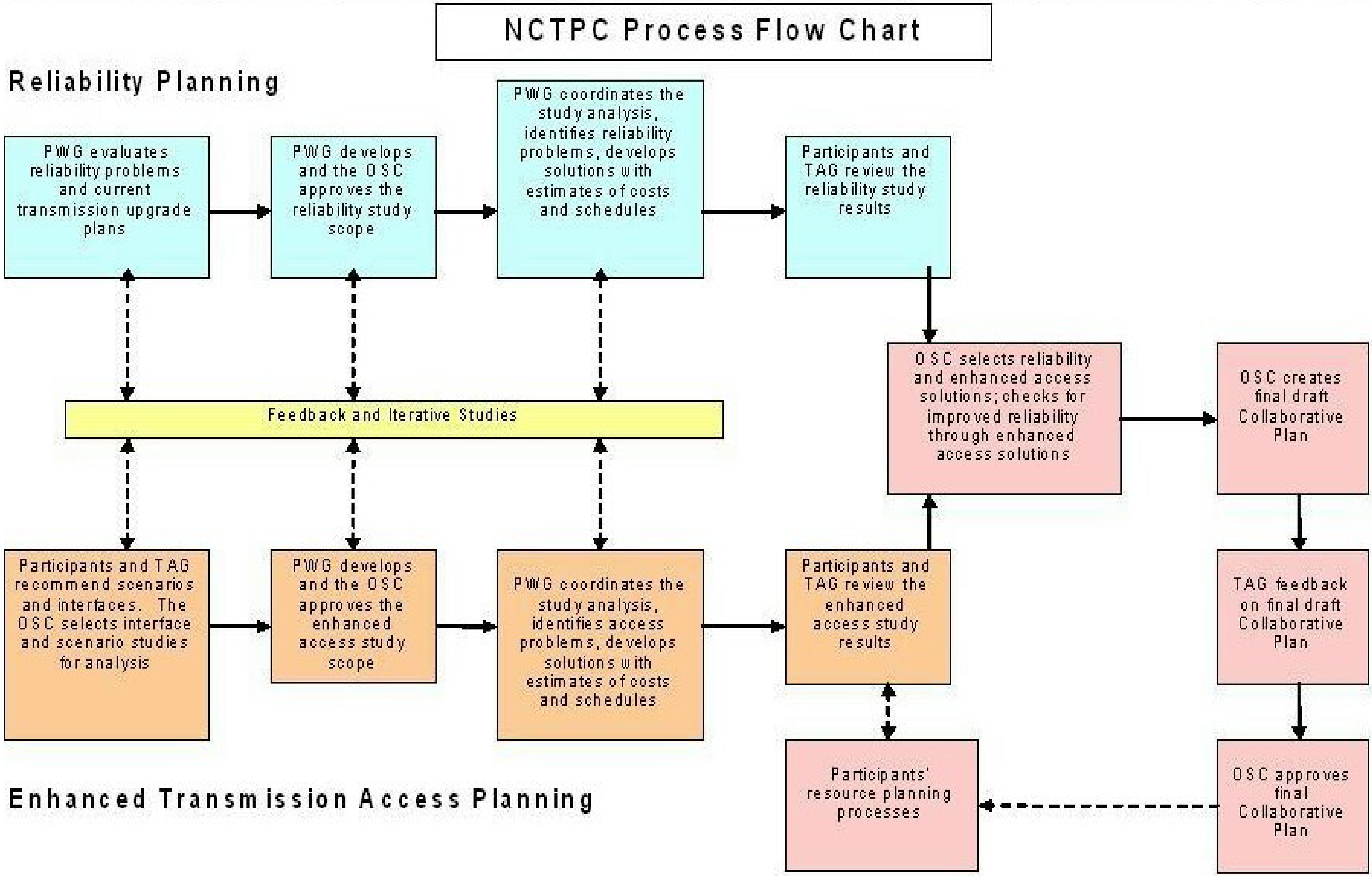
4.3.3 The process will allow for flexibility to make modifications to the development of the plan throughout the year as needs change, new needs arise, or new solutions to problems are identified.

4.3.4 The schedule for all of the activities will be set by the PWG and OSC, but will vary from year to year. The basic order of events is as set forth in Section 5, although the planning process is an iterative one.

4.4 Summary Flow Chart of Process

The following page contains a flow chart of the NCTPC Process.

[This draft flow chart reflects the current NCTPC Process and is likely to be revised in light of the reevaluation discussed *supra*.]


NCTPC Process Flow Chart
Reliability Planning
PWG evaluates reliability problems and current transmission upgrade plans
PWG develops and the OSC approves the reliability study scope
PWG coordinates the study analysis, identifies reliability problems, develops solutions with estimates of costs and schedules
Participants and TAG review the reliability study results
Feedback and Iterative Studies
OSC selects reliability and enhanced access solutions; checks for improved reliability through enhanced access solutions
OSC creates final draft Collaborative Plan
Participants and TAG recommend scenarios and interfaces. The OSC selects interface and scenario studies for analysis
PWG develops and the OSC approves the enhanced access study scope
PWG coordinates the study analysis, identifies access problems, develops solutions with estimates of costs and schedules
Participants and TAG review the enhanced access study results
TAG feedback on final draft Collaborative Plan
Participants' resource planning processes
OSC approves final Collaborative Plan
Enhanced Transmission Access Planning

5. CRITERIA, ASSUMPTIONS, AND DATA UNDERLYING THE PLAN AND METHOD OF DISCLOSURE OF TRANSMISSION PLANS AND STUDIES

5.1 Study Assumptions

5.1.1 The PWG will select the study assumptions for the analysis based on direction provided by the OSC.

5.1.2 Once the PWG identifies the study assumptions, they will be reviewed with the TAG before the set of final assumptions are approved by the OSC. The process for this dialogue is in-person meetings, written submissions, and/or other forms of communication selected by TAG members. Input should be provided in the timeframes agreed upon.

5.1.3 The study assumptions shall be set forth in an annual *Study Scope Document.*

5.1.4 The Transmission Providers will prepare the base case models. These models will be reviewed with the PWG to ensure that they represent the study assumptions approved by the OSC.

5.1.5 The Transmission Providers will also develop the necessary change case models as required to evaluate different resource supply scenarios and enhanced transmission access scenarios as directed by the OSC. Such change case models will also be reviewed with the PWG to ensure that they represent the study assumptions approved by the OSC.

5.2 Study Criteria

5.2.1 The PWG establishes the planning criteria by which the study results will be measured, in accordance with NERC and SERC Reliability Standards and individual Transmission Provider criteria.

5.2.2 For the Duke Transmission System, the following documents describe the criteria used by Duke. Such documents may be obtained from Duke through the contact listed on the Duke Website, but may be subject CEII protection.

Transmission System Planning Guidelines
Facility Connection Requirements
[Note: List is incomplete at this time and will be completed by December 7th]

5.2.3 For the Progress Transmission System, the following documents describe the criteria used by Progress. Such documents may be obtained from Progress through the contact listed on the Progress Website, but may be subject CEII protection.

Progress' Transmission Planning Reliability Criteria
Facility Connection Requirements
[Note: List is incomplete at this time and will be completed by December 7th]

5.3 Data Collection and Case Development

5.3.1 The most current Multi-Regional Modeling Working Group (MMWG) or SERC Long-Term Study Group model will be used for the systems external to Duke and Progress as a starting point for the base case to be used by both Progress and Duke. The base case will include the detailed internal models for Progress and Duke and will include current transmission additions planned to be in-service for given years.

5.3.2 The following data are relevant to the development of internal models for Progress and Duke:

Load and resource projections provided by network customers (including the native load of the NCTPC Participants);

Confirmed, firm point-to-point transmission service reservations (including rollover rights);

Generation real and reactive capacity data;

Generation dispatch priority data;

Transmission facility impedance and rating data; and

Interchange data adjusted to correctly model transfers associated with designated Network Resources from outside the Transmission Providers' Control Areas.

5.3.3 The Transmission Providers collect the necessary planning data and information that are not already in their possession. Any guidelines, data formats, and schedules for the data and information exchange will be established by the PWG. The timing of this data collection process is established as part of the development of the annual study work plan that is prepared by the PWG, reviewed with TAG, and approved by the OSC.

5.3.4 TAG members may provide additional input into the data collection process (i.e., the provision of data not required to be submitted under this Tariff), such as providing information on future point-to-point transmission service scenarios. Such non-required information may be used in the appropriate study process.

5.3.5 Transmission Customers should provide the Transmission Providers with timely written notice of material changes in any information previously provided relating to load, resources, or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide service.

5.3.6 Additional cases will be developed as required for different scenarios to evaluate other options to meet load demand forecasts in the study, including where fictitious or as yet undesignated network resources are deemed to be designated. Other cases may be developed and approved by the OSC to evaluate enhanced access scenarios, such as predicted future point-to-point transmission uses, as submitted by the TAG. **[May be reevaluated in light of Order No. 890.**

5.3.7 The Case Development details will be identified in the annual *Study Scope Document.*

5.3.8 Sufficient information will be made available, subject to CEII and confidentiality restrictions, to enable interested persons to replicate the results of planning studies. **[The process for making such information available has not been determined and will be formalized by December 7, 2007.]**

5.4 Methodology

5.4.1 The PWG determines the methodologies that will be used to carry out the technical analysis required for the approved studies. The PWG also determines the specific software and models that will be utilized to perform the technical analysis. The study methodology will be identified in the annual *Study Scope Document.*

5.5 Technical Analysis and Study Results

5.5.1 The PWG performs the technical study analysis in accordance with the OSC approved study methodology and produces the study results.

5.5.2 Results from the technical analysis are reported to identify transmission elements approaching their limits such that all NCTPC Participants are made aware of potential issues and appropriate steps can be identified to correct these issues, including the potential of identifying previously undetected problems.

5.5.3 Study results are made available to the TAG.

5.6 Assessment and Problem Identification

5.6.1 The Transmission Providers provide the summary data identifying the reliability problems and causes resulting from their assessments and comprehensively review the information with the PWG. The PWG evaluates the technical results provided by the Transmission Providers to identify problems and issues and reports to the OSC.

5.6.2 The TAG is provided information relating to technical assessments and problem identification.

5.7 Solution Development

5.7.1 The PWG identifies potential solutions to the transmission problems identified and will test the effectiveness of the potential solutions through additional analysis as required and ensure that the solutions meet the study criteria previously developed.

5.7.2 All options that satisfactorily resolve an identified reliability problem would be given consideration.

5.7.3 The Transmission Providers estimate the costs for each of the proposed transmission solutions (e.g., cost, cash flow, present value) and develop a rough schedule estimate to complete the construction of the proposed facility. This information is reviewed and discussed by the PWG.

5.8 Selection of Preferred Transmission Plan

5.8.1 The PWG compares all of the alternatives and select the preferred solution by balancing the project cost, benefit, and associated risks.

5.8.2 The PWG selects a preferred set of transmission improvements that provides the most reliable and cost effective transmission solution while prudently managing the associated risks.

5.8.3 The PWG provides the OSC and the TAG with their recommendations based on this selection process.

5.9 Collaborative Transmission Plan Report

5.9.1 The PWG prepares a draft "Collaborative Transmission Plan Report" based on the study results and the recommended transmission solutions and provides to the OSC for review. The draft Report describes the plan in a manner that is understandable to stakeholders (*e.g.*, describing any needs, the underlying assumptions, applicable planning criteria, and methodology used to determine the need), rather than simply reporting engineering results. The report includes a comprehensive summary of all the study activities as well as the recommended transmission improvements including estimates of costs and construction schedules.

5.9.2 The OSC forwards the draft report to the TAG for their review and discussion. The PWG members are the technical points of contact that can respond to questions regarding modeling criteria, assumptions, and data underlying the Report. The TAG members may discuss, question, or propose alternatives for any upgrades identified by the draft Report.

5.9.3 The OSC evaluates the results and the PWG recommendations and the TAG input. The OSC approves the final Collaborative Transmission Plan for posting on the NCTPC Website. The Plan also is posted on the Transmission Providers' OASIS and distributed to the TAG.

5.9.4 The Collaborative Transmission Plan Report allows the NCTPC Participants to identify alternative, least-cost resources to include with their respective Integrated Resource Plans. Other stakeholders can similarly use this information for their own resource planning purposes.

5.10 Status Reports

5.10.1 As part of the NCTPC Process, the Transmission Providers periodically provide the TAG a report on the status of the transmission upgrades presented in the previous Collaborative Transmission Plans. The update is posted on the NCPTC Website and includes the following information: the name of the project, the issue it resolves, the name of the relevant Transmission Provider(s), the original planned in-service date and the current expected in-service date.

6. DISPUTE RESOLUTION MECHANISM

6.1 NCTPC Process Disputes

6.1.1 The OSC voting structure allows the ITP to cast a tie breaking vote if necessary to decide on a particular issue.

6.1.2 A Transmission Provider has the right to reject an OSC decision if it believes that it would harm reliability.

6.1.3 Any NCTPC Participant has the right to seek assistance from the NCUC Public Staff to mediate an issue and render a non-binding opinion on any disputed decision.

6.1.4 If the Participants cannot resolve a disputed decision by NCUC Public Staff facilitation, they may seek review from a judicial or regulatory body that has jurisdiction.

[The NCTPC is evaluating how disputes raised by TAG members relating to the NCTPC Process will be resolved.]

6.2 Transmission Siting Disputes

6.2.1 The South Carolina Code of Laws Section 58, Chapter 33 addresses disputes involving utilities' transmission projects that require South Carolina authorization through the certificates of public convenience and necessity process.

6.2.2 NCUC Rule R8-62 addresses disputes involving utilities' transmission projects that require North Carolina authorization through the certificates of public convenience and necessity process.

6.3 Integrated Resource Planning Disputes

6.3.1 The NCUC allows public participation in and may hold hearings regarding matters related to integrated resource planning.

6.3.2 The SC PSC allows public participation in and may hold hearings regarding matters related to integrated resource planning.

6.4 Tariff Disputes

6.4.1 The dispute resolution process provisions included in this Tariff apply to disputes involving compliance with the Commission's transmission planning obligations set forth in Order No. 890. Matters over which the Commission does not have jurisdiction, including planning to meet retail native load of the Transmission Providers shall not be within the scope of the dispute resolution process of this Tariff.

6.5 Regional Reliability Project Planning Disputes

6.5.1 The Commission's Dispute Resolution Service would be used to settle any issues arising from the cost allocation related to Regional Reliability Projects, discussed *infra,* that involve transmission providers outside the NCTPC.

7. TRANSMISSION COST ALLOCATION

7.1 OATT Cost Allocation

7.1.1 The costs of Reliability Projects included in the Collaborative Transmission Plan are allocated in accordance with this Tariff. "Regional Reliability Projects," as discussed below, are an exception to this rule.

7.1.2 While the Transmission Providers study economic upgrades through ETAP, they do not have an obligation to build or fund such projects and thus the projects studied are not included in the Collaborative Transmission Plan, unless and until either: 1) a transmission service request is submitted to the appropriate Transmission Provider(s) or 2) an RETP is fully subscribed.

7.1.3 If a transmission service request is submitted under this Tariff for an economic project, its costs will be allocated in accordance with this Tariff.

7.2 Regional Reliability Project Cost Allocation

7.2.1 An "avoided cost" cost allocation methodology will apply to reliability projects where there is a demonstration that a regional transmission solution and regional approach to cost allocation results in cost savings.

7.2.2 The NCTPC Planning Process results in a set of projects that satisfy the reliability criteria of the Transmission Providers who are a party to the Participation Agreement (i.e., Reliability Projects). Through this process, a project may be identified that meets a reliability need in a more cost-effective manner than if each Transmission Provider were only considering projects on its system to meet its reliability criteria. A Regional Reliability Project can be defined as any reliability project that requires an upgrade to a Transmission Provider's system that would not have otherwise been made based upon the reliability needs of the Transmission Provider. A Regional Reliability Project must have a cost of at least $1 million to be subject to the avoided-cost cost allocation methodology. The costs of a Regional Reliability Project with a cost of less than $1 million would be borne by each Transmission Provider based on the costs incurred on its system.

7.2.3 Unless a Regional Reliability Project is determined by the NCTPC to be the most cost-effective solution to a reliability need, it will not be selected to be included in the Collaborative Transmission Plan. But, if a Regional Reliability Project is cost effective, it will have its costs allocated based on an avoided cost approach, whereby each Transmission Provider looks at the stand-alone approach to maintaining reliable service and shares the savings of not implementing the stand-alone approach on a pro-rata basis. The avoided cost approach formula can be expressed as follow:

(Transmission Provider$_x$'s Avoided Cost/Total
Avoided Cost) * cost of Regional Reliability Project
= Transmission Provider$_x$'s Cost Allocation

(Transmission Provider$_y$'s Avoided Cost/Total
Avoided Cost) * cost of Regional Reliability Project
= Transmission Provider$_y$'s Cost Allocation

These cost responsibility determinations will then be reflected in transmission rates. The avoided cost approach also will take into account in determining avoided costs, the acceleration or delay of Reliability Projects. Examples of the application of the avoided-cost approach may be found in the *NCTPC Transmission Cost Allocation Whitepaper*.

7.2.4 If a Regional Reliability Project that is suitable for this alternate cost allocation approach involves a Transmission System(s) outside the NCTPC, the costs should be fairly allocated among the affected

Transmission Providers based on good-faith negotiation among the parties involved using the “avoided cost” approach outlined above used as a starting point in the negotiations. The resulting transmission costs and the associated revenue requirements of each Transmission Provider will be recovered through their respective existing rate structures at the time.

7.3 RETP Cost Allocation

7.3.1 The costs of upgrades or facilities that result from RETPs are allocated on a “requestor pays” basis.

7.3.2 Transmission Customer(s) that are subscribing to the RETP would provide the up-front funding of any transmission construction that was required to ensure that the path was available for the relevant time period. These “requestor(s)” would be the Transmission Customers that were awarded the MW as a result of the successful subscription during the Open Season process. On the Duke and/or Progress systems, the Transmission Customer would receive a levelized repayment of this initial funding amount from Duke and/or Progress in the form of monthly transmission credits over a maximum 20-year period. The Transmission Providers will be permitted to work with the Transmission Customers to provide shorter or different crediting. As credits are paid, Duke and Progress would have the opportunity to include the costs of upgrades that were needed for the RETP in transmission rates, similar to the Generator Interconnection pricing/rate approach.

7.3.3 No compensation is provided to the “requestors” of the RETPs for any “head-room” that would be created on the Transmission Systems. The total project cost for the transmission expansion required due to an RETP will be adjusted to provide compensation for the positive transmission impacts that the RETP would provide, given the existing Collaborative Transmission Plan.

7.3.4 This RETP concept and cost allocation methodology applies to the NCTPC footprint. The NCTPC Participants will work with other regions to adopt approaches that are consistent with its requestor pays approach.

8. COST ALLOCATION FOR PLANNING COSTS

8.1 NCTPC-Related Planning Costs

8.1.1 Each NCTPC Participant bears its own expenses.

8.1.2 TAG members bear their own expenses.

8.1.3 The costs of the NCTPC base reliability studies are born by Duke and Progress.

8.1.4 Costs associated with incremental reliability studies, the ITP's costs, and the costs of the ETAP are all allocated to NCTPC Participants in the manner set forth in the *Participation Agreement*. [**A provision relating to costs of studies that are requested, but are outside the studies whose costs are allocated pursuant to this section, will be included in the Final Attachment K.]**

8.1.5 NCTPC Participants may challenge the correctness of NCTPC cost allocations.

8.1.6 For the Transmission Providers, transmission planning costs are a routine cost-of-service item that would be reflected in both wholesale and retail transmission rates. There is no plan to allocate planning costs to customers, other than as described above, or as contemplated by this Tariff when a customer makes a specific request that must be studied.

8.2 Non-NCTPC-Related Planning Costs

Each Transmission Provider will bear its own costs of planning-related activities that are not occurring through the rubric of the NCTPC Process, which costs may be recovered in rates, pursuant to the then-applicable ratemaking policies.

9. CONFIDENTIALITY

9.1 The Transmission Providers will take appropriate steps to protect CEII information. **[NCTPC needs to determine appropriate means of implementation and will provide additional detail by December 7, 2007.]**

9.2 Identification of (non-CEII) Confidential Information

9.2.1 Aside from CEII restrictions, the only data that is expected to require confidentiality protection is customer-related information that is proprietary to a particular wholesale or retail customer ("Confidential Information").

9.2.2 The confidentiality of such customer information is determined in the first instance by a NCTPC Participant or TAG member. NCTPC Participants will abide by any internal, state-mandated, and/or FERC-mandated confidentiality rules, policies, and laws with regard to customer information in their possession in determining whether such information is confidential.

9.2.3 A person providing information that it considers to be Confidential Information to the PWG or OSC must indicate that the information is Confidential Information.

9.3 Availability of (non-CEII) Confidential Information

9.3.1 The NCTPC Participants will mask Confidential Information in documents that are released to the public.

9.3.2 Confidential Information will be made available, to the extent necessary, only to the NCTPC Participants, as limited by the *Participation Agreement*. Each NCTPC Participant is restricted from sharing or giving access to Confidential Information with any employee, representative, and/or organization directly involved in the sale and/or resale of electricity in the wholesale electricity such that they do not receive preferential treatment or a competitive advantage.

9.3.3 There may be occasions where guests of the NCTPC, the TAG, or others (such as neighboring Transmission Providers) may be provided Confidential Information. In such circumstances, such persons will be expected to sign confidentiality agreements that will in effect bind them to the confidentiality provisions in the *Participation Agreement*. Any disclosures of Confidential Information will only be made if otherwise in accordance with the FERC Standards of Conduct and Code of Conduct.

9.4 Role of the ITP

9.4.1 The ITP is tasked with ensuring that no marketing/brokering organizations receive preferential treatment or achieve competitive advantage through the distribution of any transmission-related information in the TAG.

9.4.2 The ITP ensures that the confidentiality of information and Standards/Code of Conduct requirements are being adhered to within the TAG process, to the extent necessary.

10. INTER-REGIONAL COORDINATION

The Transmission Providers will coordinate with other transmission systems primarily through participation in SERC, other inter-regional study groups, and bilateral agreements between Duke and/or Progress and transmission systems to which they are interconnected.

10.1 Description of SERC Planning-Related Activities

10.1.1 All transmission providers within SERC participate in the Transmission Assessment Study Process which ensures that there is coordination of modeling data and assessment of transfer capability for the entire Southeast region. Through the SERC Transmission Assessment Study Process, the Transmission Providers will coordinate with other interconnected systems in SERC by sharing their modeling data, assumptions, and transmission expansion plans.

10.1.2 The Transmission Providers will participate in SERC studies conducted to assess the performance of the interconnected system under both normal and contingency conditions and to assess the ability of the interconnected system to support large economy or emergency power transfers across subregions.

10.1.3 Duke and Progress must abide by SERC's own confidentiality requirements.

10.1.4 SERC study reports and model base cases are reported to FERC as part of the annual Form 715 filings and are available to interested parties from SERC.

10.2 Description of ERAG & SERC-RFC East Planning-Related Activities

10.2.1 SERC is a Member of the Eastern Interconnection Reliability Assessment Group (ERAG) along with the Florida Reliability Coordinating Council, Inc., the Midwest Reliability Organization, the Northeast Power Coordinating Council, Inc., ReliabilityFirst Corporation, and the Southwest Power Pool. ERAG augments the reliability of the bulk-power system through periodic reviews of generation and transmission expansion programs and forecasted system conditions within the regions served by ERAG members.

10.2.2 The Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group (MMWG) administers the development of a library of power-flow base case models for the benefit of members.

10.2.3 The SERC-RFC East study group was established in 2006 and is a sub-group within the ERAG structure. Through the SERC-RFC East study group, coordination of plans, data and assumptions is achieved between Tennessee Valley Authority, VACAR, and the transmission systems of the eastern portion of PJM.

10.3 Description of VACAR Planning-Related Activities

10.3.1 The Transmission Providers both participate with Fayetteville, NCEMC, ElectriCities, South Carolina Electric & Gas Company, South Carolina Public Service Authority, Southeastern Power Administration, Dominion Virginia Power, and Alcoa-Yadkin, Inc. in the VACAR Planning Task Force.

10.3.2 A VACAR contract agreement provides for coordination of planning between the various entities within the VACAR region.

10.3.3 As members of the VACAR Planning Task Force, the Transmission Providers will engage in studies of the bulk power supply system.

VACAR typically analyzes the performance of their proposed future transmission systems based on five- or ten-year projections. VACAR studies are similar to those conducted for SERC, but are focused on the VACAR subregion, although VACAR coordinates with Southern and TVA under existing agreements.

10.4 Bilateral Planning-Related Activities

Through bilateral interconnection agreements or joint operating agreements with the interconnected transmission systems of American Electric Power, TVA, Southern Companies, PJM, Dominion, SCE&G, Santee Cooper, and Yadkin, Duke and Progress perform coordinated planning studies on an as-needed basis.

10.5 Description of Inter-Regional Participation Process Planning-Related Activities

10.5.1 Duke and Progress are working with a group of southeast utilities in the development of a process whereby stakeholders could request economic studies that would be evaluated on an inter-regional basis. The framework for this process is provided in a document entitled "Inter-Regional Participation White Paper." **[This framework will be vetted with the southeast stakeholders with the expectation that a more fully developed process will be described in the final Attachment K that will be filed in December, 2007.]**

11. INTEGRATED RESOURCE PLANNING

In addition to the NCTPC Process, the Transmission Providers must abide by state laws regarding Integrated Resource Planning (IRP). The information provided below is intended to assist stakeholders who may want to participate in state IRP and siting proceedings.

11.1 North Carolina

North Carolina Utilities Commission (NCUC) analyzes the probable growth in the use of electricity and the long-range need for future generating capacity in North Carolina. Duke and Progress annually furnish the NCUC a report of their respective resource plans, which contain a ten-year forecast of loads and generating capacity. The report describes all generating facilities and known transmission facilities with operating voltage of 161 kV or more which, in the judgment of the utility, will be required to supply system demands during the 10-year forecast period. Such filings must include a section containing a comprehensive analysis of their Demand-Side Management (DSM) plans and activities.

11.2 South Carolina

Section 58-37-40 of the South Carolina Code of Laws requires that all electrical utilities prepare integrated resource plans and submit them to the State Energy Office. The plans must be submitted every three years and must be updated on an annual basis. For electrical utilities subject to the jurisdiction of the SC PSC, submission of the IRP plans required by the SC PSC (which similarly are submitted triennially and updated at least annually) constitutes compliance with the state law. The SC PSC requires that the plans submitted cover 15 years and evaluate the cost effectiveness of supply-side and demand-side options in an economic and reliable manner that considers relevant costs and benefits.

Related Documents

Duke Energy Carolinas, LLC and Progress Energy Carolinas, Inc. Draft Attachment K

NORTH CAROLINA LOAD SERVING ENTITIES' TRANSMISSION PLANNING PARTICIPATION AGREEMENT

May 20, 2005

NORTH CAROLINA LOAD SERVING ENTITIES' TRANSMISSION PLANNING PARTICIPATION AGREEMENT

This Participation Agreement ("Agreement") dated this ___ day of ______, 2005, is entered into by and among: Duke Power, a division of Duke Energy Corporation ("Duke"); Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. ("Progress"); North Carolina Electric Membership Corporation ("NCEMC"); and ElectriCities of North Carolina, Inc. ("ElectriCities"), each of which may hereinafter be referred to singularly as a "Participant" and collectively as "Participants".

RECITALS

WHEREAS, as a result of a review of issues concerning the adequacy of electric transmission infrastructure facilitated by the North Carolina Utilities Commission (the "Commission"), Duke, Progress, ElectriCities, acting for and on behalf of its member municipalities serving retail North Carolina customers, and NCEMC, acting for and on behalf of the electric cooperatives serving retail North Carolina customers, all being geographically located in the control areas of Duke and/or Progress, desire by entering into this Agreement to create and implement a collaborative electric transmission planning process for their respective service territories in North Carolina (the "Process"); and

WHEREAS, in order to create and implement the Process each Participant is willing to: (i) share confidential and proprietary transmission, load forecasts and other information with other Participants to the extent required to implement the Process; (ii) protect all such confidential and proprietary information from disclosure to the public, as provided herein, and to each Participant's marketing and/or brokering employees and representatives consistent with the Federal Energy Regulatory Commission's Standards of Conduct and Codes of Conduct; (iii) pay its fair share of the administrative costs to implement the Process; and (iv) cooperate in good faith with all other Participants to accomplish the goals of the Process and reach mutually acceptable resolution of transmission planning issues so as to minimize the need to initiate regulatory proceedings to resolve transmission adequacy issues; and

WHEREAS, the Participants desire to create an Oversight Steering Committee ("OSC") and a Planning Working Group ("PWG"), each of which will be organized and operated pursuant to the provisions of this Agreement to perform much of the work to create and implement the Process; and

WHEREAS, the Participants, through the OSC, desire to select an independent third party consultant ("ITP") to act as a facilitator for the development and conduct of the Process, including the solicitation of input from other market participants; and

WHEREAS, the Participants desire that the functions of the OSC and PWG be carried out in an atmosphere of full and complete cooperation and disclosure, but one which also protects the confidential and proprietary nature of the information made available to each Participant, the OSC, the PWG and the ITP as provided herein;

NOW THEREFORE, in consideration of the foregoing, the undertakings set forth herein and such other good and valuable consideration, the receipt and adequacy of which is hereby acknowledged, the Participants agree as follows:

1. **<u>Intent of the Participants.</u>** The Participants will exert reasonable best efforts to create and implement the Process as described herein. The objectives of the Process are to:

   a. provide load-serving entities in North Carolina an opportunity to fully participate in the electric transmission planning process in North Carolina;

   b. preserve the integrity of the current reliability and least-cost integrated resource planning process utilized to plan the expansion of the Duke and Progress (sometimes hereinafter collectively referred to as the "investor-owned utilities") transmission systems, which process shall be known as the "Reliability Planning Process;"

c. expand the transmission planning process to include analysis and consideration of: (i) increased transmission import capability to provide greater access to generation resources outside the investor owned utilities' control areas; and (ii) potential enhancements to the Duke and Progress transmission systems in order to enhance access to generation resources within the existing control areas for which there are no existing contractual arrangements, which together shall be known as the "Enhanced Transmission Access Planning Process";

d. integrate the Reliability Planning Process and the Enhanced Transmission Access Planning Process for the areas of North Carolina that are served by the Participants for the purpose of ultimately developing a single coordinated transmission expansion plan that appropriately balances costs, benefits and risks associated with the use of transmission and generation resources;

e. create the OSC, consisting of representatives from the participating investor-owned utilities, municipalities and electric cooperatives and the ITP, as provided for herein and in the document entitled "Scope – Oversight/Steering Committee (OSC)" (the "OSC Scope Document");

f. create the PWG, consisting of representatives from the participating investor-owned utilities, municipalities and electric cooperatives and the ITP, as provided for herein and in the document entitled "Scope – Planning Working Group (PWG)" (the "PWG Scope Document");

g. fulfill the direction of FERC Order 888-A that "network service is founded on the notion that the transmission provider has a duty to plan and construct the transmission system to meet the present and future needs of its native load and, by comparability, its third-party network customers"; and

h. fulfill the direction of N.C. Gen. Stat. §62-110.1(c) and North Carolina Utilities Commission Rule R8-60, in expanding the integrated resource planning process required of the utilities and electric cooperatives by providing for the results of the Process to be considered in the annual resource plans which are reviewed by the Commission, and assist the Commission in fulfilling its responsibilities to develop, publicize and keep current an analysis of the long-range needs for electricity of the citizens of North Carolina.

2. **The Oversight/Steering Committee:** The OSC will consist of eight (8) appointed members plus ex officio members as approved by the OSC. Duke, Progress, ElectriCities and the electric cooperatives shall each appoint two (2) members to the OSC and may each appoint up to two (2) alternate members, all of whose qualifications shall be materially consistent with the guidelines for OSC membership set forth in the OSC Scope Document. The alternates shall act in the absence of the appointed members, including participating in voting. The appointed members of the OSC shall select a chair and vice-chair pursuant to the procedures contained in the OSC Scope Document. Additionally, the appointed members of the OSC shall select the ITP and a representative from the ITP to be an ex officio member of the OSC (the "ITP Member"). The ITP Member shall act as a facilitator for the OSC and shall assist the chair and vice-chair in the performance of their duties as reasonably requested. The members of the OSC shall use reasonable good faith efforts to reach decisions via consensus. However, in the event that the OSC is unable to reach a decision by consensus then a decision will be reached by majority vote. When voting is conducted, each of the OSC members (or designated alternates) except the ex officio members shall have one vote. In the event of a tie vote, the ITP Member shall be entitled to one vote to break the tie. However, notwithstanding any other provisions herein, the investor-owned utilities shall not be bound by decisions of the OSC to the extent each of the investor-owned utilities reasonably determine such decisions, as related to reliability planning, are inconsistent with good utility practice or SERC and NERC established criteria or least-cost integrated resource planning principles. The investor-owned utilities shall each retain decision making authority for such decisions related to reliability planning consistent with their statutory responsibilities for reliability, subject to normal regulatory oversight.

3. **OSC Duties:** As detailed in the OSC Scope Document, the duties of the OSC shall be to:

a. review and approve transmission planning criteria and critical assumptions for the bulk transmission system (i.e., 230 kV facilities and above plus lower voltage facilities that substantively affect the Reliability Planning Process and the Enhanced Transmission Access Planning Process) and, where appropriate, develop and recommend such criteria and assumptions to be used by the PWG; provided that each transmission owner may reject any such criteria, critical assumption or recommendation if (i) it determines, in good faith, that such recommendation is not consistent with SERC and NERC established criteria, including NERC planning standards, or with good utility practice and least-cost integrated resource planning principles; or (ii) if the senior management of such transmission owner rejects such criteria and/or assumptions. In the event of such a rejection, the transmission owner's OSC member shall provide a brief, reasonably descriptive written statement of the reasons for such rejection to the OSC. The OSC shall promote consistency among the planning criteria and critical assumptions used in the Process, provided that in recognition of the differences between transmission systems, (i) the fact that a criterion or assumption differs between participating transmission systems shall not by itself constitute sufficient reason to change such a criterion or assumption; and (ii) the uniform application of any new criteria and/or assumptions to all participating transmission systems shall be determined on a case-by-case basis by the OSC;

b. promote the application of such planning criteria and/or assumptions within the territories served by the Participants;

c. review and recommend revisions to transfer capability, transmission reserve margin (TRM) and capacity benefit margin (CBM) criteria and calculations of the investor-owned utilities for consistency with SERC and NERC established criteria as well as good utility practice; recommend transfer capability, TRM and CBM criteria or methodologies which would be applied consistently in the Process, adjusted as appropriate, to accommodate local conditions that merit special consideration; provided that each transmission owner may reject any such recommendation if (i) it determines, in good faith, that such recommendation is not consistent with SERC and NERC established criteria, including NERC planning standards, or with good utility practice and least-cost integrated resource planning principles; or (ii) if the senior management of such transmission owner rejects such recommendation. In the event of such a rejection, the transmission owner's OSC member shall provide a brief, reasonably descriptive written statement of the reasons for such rejection to the OSC;

d. for the areas of the State of North Carolina served by the Participants, participate in the Reliability Planning Process, and oversee the development of the Enhanced Transmission Access Planning Process consistent with the goals set forth in Paragraph 1 hereof; and

e. direct the activities of and provide oversight for the PWG.

4. **<u>The Planning Working Group</u>:** The PWG will consist of up to twelve (12) members. Duke, Progress, ElectriCities and the electric cooperatives shall each nominate at least one and up to three members to the PWG by written notice to the OSC. The OSC shall approve the nominations of the PWG members so long as they materially meet the guidelines described in the PWG Scope Document. The appointed members of the PWG shall select a chair and a vice-chair pursuant to the procedures contained in the PWG Scope Document. Additionally, the OSC shall appoint a representative from the ITP to the PWG. The PWG shall use reasonable good faith efforts to reach decisions via consensus. However, in the event the PWG is unable to reach a decision by consensus, the decision will be referred to the OSC for resolution.

5. **<u>PWG Duties</u>:** The PWG shall be responsible, under the general direction of the OSC, for evaluation and administration of the criteria and critical assumptions used in problem identification, solution development and plan compilation in the Reliability Planning Process and the Enhanced Transmission Access Planning Process developed in accordance with the provisions of this Participation Agreement and the PWG Scope Document. Simulations required by the PWG to discharge said responsibility will be performed by the investor-owned utilities with oversight by the PWG.

6. **Reliability Planning and Enhanced Transmission Access Planning.** The Process shall consist of the integrated application of the Reliability Planning Process and the Enhanced Transmission Access Planning Process. The Reliability Planning Process will involve the creation of a transmission expansion plan based upon reliability requirements for firm load and resource projections. The OSC shall have primary responsibility for the Reliability Planning Process. The Enhanced Transmission Access Planning Process will involve the analysis of potential transmission expansion projects that would provide enhanced access to generation resources and markets inside and outside of the Duke and Progress control areas in North Carolina, and the development of corresponding transmission expansion options including the costs and schedules associated with such options. The ITP shall have primary responsibility for the Enhanced Transmission Access Planning Process, subject to oversight by the OSC. The ITP's role in developing the enhanced transmission access options shall include the development of a mechanism to solicit and obtain the input of all market participants. Cost responsibility for transmission projects identified pursuant to the Process is not addressed by this Participation Agreement. Neither the provisions of this Participation Agreement nor any components of the Process are intended to replace or diminish the obligations of Duke and Progress under their respective open access transmission tariffs ("OATTs") to, as applicable, provide transmission service to, or undertake construction of transmission expansion projects for, any transmission customer. Transmission expansion options related to the Enhanced Transmission Access Planning Process will remain fully subject to the current reservation and request processes conducted through the OASIS, and these processes do not replace such OASIS processes.

7. **Decisions of the OSC:** Subject to the provisions of Paragraphs 2 and 3 above, the Participants will abide by the decisions of the OSC. However, any Participant may request that the North Carolina Utilities Commission Public Staff ("Public Staff") render a non-binding opinion with regard to any disputed decision of the

OSC and any decision of the investor-owned utility superseding a decision by the OSC ("Disputed Decision"). Should the parties be unable to resolve the Disputed Decision through such facilitation by the Public Staff, any Participant may seek review of the Disputed Decision by any regulatory or judicial body with jurisdiction over the subject matter of the Disputed Decision.

8. **Definition of Confidential Information:** For purposes of this Participation Agreement, the term "Confidential Information" means any and all information designated by a Participant as proprietary and confidential that is provided to another Participant, the OSC and/or the PWG, and confidential and proprietary information developed by the OSC, the PWG and/or the ITP, whether printed, written, oral, electronic or on software. All transmission information shall be considered "Confidential Information" regardless of whether a Participant has specifically designated it as confidential or proprietary. Notwithstanding the preceding provisions of this paragraph, the term "Confidential Information" shall not include any information that a Participant can demonstrate (a) is or has been independently developed by that Participant, or is lawfully received by that Participant from another source having the right to furnish such information to either; (b) has become generally available to the public without breach of this Participation Agreement by that Participant; or (c) that Participant was rightfully in possession of for some other lawful purpose and without restrictions on its use prior to the time the Participant became involved in the Process.

9. **Obligation of Confidentiality:** The Participants shall not discuss among themselves specific products and/or services made available to them or offered by them, or prices or terms of such products and/or services. If the identity of or other information about specific generation resources is required in order to conduct reliability or enhanced transmission access studies, such information may be disclosed among the Participants, but shall be masked to the extent reasonably possible. Each Participant shall ensure that all Confidential Information to which it has access shall be kept confidential by the Participant and by its employees,

attorneys, accountants, financial advisors, consultants, and in the case of the municipalities and electric co-ops, representatives or members (collectively, "Representatives"), to the extent permitted by law. Among other things, each Participant shall ensure that, except with the prior written consent of the Participant from whom the Confidential Information was obtained, which consent may be withheld in the sole discretion of such Participant, the Confidential Information shall not: (a) be used for any purpose or proceeding whatsoever other than performing duties and/or actions directly related to the Process; (b) be distributed or disclosed in any manner whatsoever except as required by law or as permitted by this Participation Agreement; or (c) be distributed to any Representatives of a Participant who are not, consistent with this Participation Agreement, normally involved with the Process (except to the extent said Representatives require access to the Confidential Information to perform duties or obligations directly related to the Process); or (d) be distributed to any third party except as required by law or as specifically permitted hereunder. However, the receiving Participant may transmit Confidential Information to such Representatives who need to know the Confidential Information for the purposes of the receiving Participant performing its duties and obligations associated with the Process, provided that the Participant and said Representatives comply with the provisions of Paragraph 10 below.

10. **Obligations of Participants and Representatives:** To meet its confidentiality obligations under this Participation Agreement, particularly those set out in Paragraph 9, above, each Participant shall maintain a list of each of its Representatives who have access to Confidential Information. Each such Representative on the list shall be informed of and instructed in the terms of this Participation Agreement by the Participant, instructed by the Participant that they are to comply with those terms and shall acknowledge in writing that they have read this Participation Agreement and understand its terms prior to receiving access to any Confidential Information. If a Representative of a Participant acts in a manner that results in the Representative breaching the confidentiality terms

of this Participation Agreement, the Participant will (a) immediately upon learning of such breach notify the OSC; (b) review its internal policies and procedures to determine the cause of such breach; (c) implement actions reasonably designed to prevent a recurrence of such breach; and (d) promptly notify the OSC as to the cause of such breach and actions taken pursuant to (c).

11. **Ownership of Confidential Information:** All Confidential Information developed or furnished by a Participant shall be and will remain the property of such Participant. All Confidential Information developed or produced by the OSC and/or the PWG shall be and will remain the property of all Participants. Nothing contained in this Participation Agreement shall be construed as granting or conferring upon any Participant any rights by license or otherwise, express or implied, to the Confidential Information.

12. **Disclosures Required by Court Order or Law:** In the event that any Participant receives a request to disclose any or all of the Confidential Information under the terms of (a) a state freedom of information act, public records act or similar statute, (b) the Federal Freedom of Information Act, (c) a valid and effective subpoena or order issued by a court or governmental body or agency having jurisdiction over a Participant, or (d) pursuant to an appropriate request for production of documents in any proceeding before an administrative agency or court having jurisdiction over a Participant, such Participant shall notify all other Participants and the OSC immediately of the existence, terms and circumstances surrounding such a request so that one or more of the Participants may seek an appropriate protective order or take such other action as it deems appropriate to protect against the release of Confidential Information. If the Participant is compelled to disclose any of the Confidential Information, only that portion thereof compelled to be disclosed will be disclosed, and the Participant shall use reasonable best efforts to obtain an order or other reliable assurance that confidential treatment shall be accorded to the Confidential Information so disclosed.

13. **Remedies.** Each Participant agrees that any threatened or existing violation of the confidentiality provisions of this Participation Agreement would cause the other Participants irreparable harm for which they would not have an adequate remedy at law, and that the other Participants shall be entitled to seek immediate injunctive relief prohibiting such violation. In the event that Confidential Information is disclosed in violation of this Participation Agreement, nothing contained herein shall preclude any Participant from pursuing an action for damages or for enforcement of any other rights or remedies available to them at law or in equity.

14. **Return of Confidential Information:** Upon the written or electronically transmitted request of the Participant from whom the Confidential Information was obtained, all documents, records, materials and similar repositories of Confidential Information, including any and all copies thereof in possession of another Participant obtained by such Participant in the course of performing duties and/or obligations associated with the Process, or obtained by the OSC or PWG, shall be promptly surrendered and delivered to the Participant from whom the Confidential Information was obtained. Confidential Information developed or produced by the OSC and/or the PWG shall be promptly returned to all Participants at such time that the OSC and/or PWG deems it to be appropriate.

15. **Standards/Code of Conduct:** Each Participant shall prohibit the sharing of any Confidential Information with any employee, Representative, and/or organization directly involved in the sale and/or resale of electricity in the wholesale electricity market; prohibit its employees, Representatives, and/or organizations involved directly in the sale and/or resale of electricity in the wholesale electricity market from having access to any Confidential Information; and ensure its employees, Representatives, and/or organizations involved directly in the sale and/or resale of electricity in the wholesale electricity market do not receive preferential treatment nor a competitive advantage through access to Confidential Information. If any

Participant acts in a manner contrary to such rules, inadvertently or otherwise, the Participant will (a) immediately upon learning of such incident notify the OSC; (b) review its internal policies and procedures to determine the cause of such incident; (c) implement actions reasonably designed to prevent a recurrence of such incident; and (d) promptly notify the OSC as to the cause of such incident and actions taken pursuant to (c). A breach of this Paragraph 15 may, subject to a majority vote of the OSC, result in the breaching Participant and its employees and Representatives being prohibited from participating in the Process.

16. **Cost Responsibility:** Each Participant shall bear its individual expenses of participation such as travel expenses. The costs associated with the creation and implementation of the Process, including, but not limited to, the costs associated with the OSC, the PWG, and the ITP, shall be the responsibility of all Participants as outlined below:

a. Costs associated with base reliability studies as defined by the OSC shall be the responsibility of the investor-owned utilities.

b. Costs associated with proposed incremental reliability studies which are approved by the OSC will be allocated among the Participants. Duke and Progress will each be responsible for one-third of such costs, and NCEMC and ElectriCities will each be responsible for one-sixth of such costs. If the OSC does not so approve a proposed incremental reliability study, the requesting party may request that the OSC authorize that the study be performed at the cost of the requesting party or parties, and the OSC shall consider such a request.

c. Costs associated with the ITP will be allocated among the Participants. Duke and Progress will each be responsible for one-third of such costs, and NCEMC and ElectriCities will each be responsible for one-sixth of such costs.

d. Costs associated with enhanced transmission access planning, including enhanced transmission access studies as defined and approved by the OSC, will be allocated among the Participants. Duke and Progress will each be responsible for one-third of such costs, and NCEMC and ElectriCities will each be responsible for one-sixth of such costs. If the OSC does not approve a proposed enhanced transmission access study, the requesting party may request that the OSC authorize that the study be performed at the cost of the requesting party or parties and the OSC shall consider such a request.

e. The results of studies performed pursuant to this Participation Agreement shall be available to all Participants, and to third parties upon request and approval of the OSC, regardless of which Participants fund such studies.

17. **Administration of Receipts and Disbursements:**

a. At its first meeting the OSC shall appoint a Participant or a third-party to act as treasurer (provided that such Participant or third-party agrees to serve as treasurer), the appointment of which may be changed by the OSC at any time upon reasonable notice to the Participants. The treasurer may resign upon 90 days written notice to the OSC, and upon such notice the OSC will designate a new treasurer upon reasonable notice to the Participants (provided that such Participant or third-party agrees to serve as treasurer). The treasurer shall receive and disburse funds and carry out such other reasonable responsibilities as the OSC shall establish, including, but not limited to, providing periodic (as defined by the OSC) reports to each of the Participants of all receipts and disbursements.

b. Any Participant may, in good faith, challenge before the OSC the correctness or appropriateness of any costs to be allocated among the Participants or any allocations thereof. Any Participant or third party submitting a bill for which costs are to be allocated shall provide reasonable and customary documentation with the bill. Any revisions or adjustments may be in the form of an adjustment of subsequent bills or refund requests.

18. **Term and Withdrawal from Process.** Participation by the Participants in the Process is voluntary. This Participation Agreement shall have an initial term of two years from the date first above written and may be renewed upon prior agreement of the Participants. The Participants will review the Participation Agreement approximately six months prior to the expiration of the initial term in

anticipation of a potential decision to renew this Participation Agreement. Additionally, any Participant shall be free to withdraw from the Process and this Participation Agreement at any time for any reason upon 180 days' prior written notice to the other Participants, provided, however, that any Participant withdrawing from the Process shall continue to be responsible for the payment of all costs of the Process properly allocable to such Participant pursuant to Paragraph 16 that were incurred prior to the effective date of withdrawal, and shall complete all actions and tasks which the Participant is either performing or has agreed to perform as a result of the Process as of the date of such Participant's notice of withdrawal. Additionally, any Participant shall be free to withdraw from the Process and this Participation Agreement at any time upon written notice to the other Participants, if the withdrawing Participant's continued participation is rendered illegal, impossible or inappropriate by action of any regulator of said Participant.

19. **Entire Agreement.** This Participation Agreement plus the scope documents for the OSC and PWG set forth the entire agreement and understanding of the Participants concerning the subject matter hereof, and no representation, promise, inducement or statement of intention not set forth in this Participation Agreement has been made by or on behalf of any Participant hereto. In the event that the provisions of this Participation Agreement conflict with those of the OSC Scope Document or the PWG Scope Document, this Participation Agreement shall control unless otherwise unanimously agreed upon by the OSC.

20. **Severability.** Subject to the provisions of Paragraph 18 hereof, if any provision of this Participation Agreement is held to be illegal, invalid or unenforceable, such provisions shall be fully severable and this Participation Agreement shall be construed as if the illegal, invalid and unenforceable provision had never been a part of this Participation Agreement and the remaining provisions of this Participation Agreement shall be given full force and effect.

21. **Survival.** The restrictions and obligations of this Participation Agreement shall survive any expiration, termination or cancellation of this Participation Agreement and shall continue to bind the Participants and their successors and permitted assigns.

22. **Assignment.** No Participant shall assign any of its rights or delegate any of its duties hereunder to a third party without the prior written consent of all other Participants, such consent not to be unreasonably withheld.

23. **Governing Law.** This Participation Agreement shall be governed by and construed in accordance with the laws of the State of North Carolina.

IN WITNESS WHEREOF, each of the Participants, intending to be legally bound by the provisions of this Participation Agreement, has caused its duly authorized representatives to execute this Participation Agreement as of the date set forth above.

PROGRESS ENERGY CAROLINAS, INC.

By: ________________________

Title: ________________________

DUKE POWER, a division of DUKE ENERGY CORPORATION

By: ________________________

Title: ________________________

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

By: ________________________

Title: ________________________

ELECTRICITIES OF NORTH CAROLINA, INC.

By: ________________________

Title: ________________________

North Carolina Transmission Planning Collaborative Process

Overview

The purpose of the North Carolina Transmission Planning Collaborative (NCTPC) Process is more fully described in the Participation Agreement. In general, however, the NCTPC Process was established to:

1) provide the Participants (Duke Power, Progress Energy Carolinas, Inc, North Carolina Electric Membership Corporation and ElectriCities of North Carolina) and other stakeholders an opportunity to participate in the electric transmission planning process for the state of North Carolina,
2) preserve the integrity of the current reliability and least-cost planning processes,
3) expand the transmission planning process to include analysis of increasing transmission access to supply resources inside and outside the control areas of Duke Power (Duke) and Progress Energy (Progress), and
4) develop a single coordinated transmission plan for North Carolina that includes reliability and enhanced transmission access considerations while appropriately balancing costs, benefits and risks associated with the use of transmission and generation resources.

The overall NCTPC Process includes the Reliability Transmission Planning and Enhanced Transmission Access Planning (ETAP) processes, whose studies will be concurrent and iterative in nature. The general scope of these studies is outlined in the attached Appendix. It is expected that there will be considerable feedback and iteration between the two processes as each effort's solution alternatives affect the other's solutions.

The Oversight Steering Committee (OSC) will manage the NCTPC Process. The Planning Working Group (PWG) will support the development of the NCTPC Process and coordinate the study development. The Transmission Advisory Group (TAG) provides advice and makes recommendations regarding the development of the NCTPC Process and the study results.

Figure 1 below illustrates the major steps associated with the NCTPC Process.

Reliability Planning Process

The Reliability Planning Process is the transmission planning process that has traditionally been used by the transmission owners to provide safe and reliable transmission service at the lowest reasonable cost. This transmission planning process is being expanded to include the active participation of the Participants and input from other stakeholders through the TAG.

The Reliability Planning Process will follow the steps outlined in Figure 1. The OSC will approve the scope of the reliability study, oversee the study analysis being performed by the PWG, evaluate the study results, and approve the final reliability study results. The Reliability Planning Process will begin with the incumbent transmission owners' most recent reliability planning studies and current transmission upgrades plans. The PWG will coordinate the development of the reliability studies based upon the OSC-approved scope and prepare a report with the recommended transmission reliability solutions.

The final results of the Reliability Planning Process will include summaries of the estimated costs and schedules to provide any transmission upgrades and/or additions needed to maintain a sufficient level of reliability necessary to serve the native load of all Participants. The reliability study results will be reviewed with the TAG.

Enhanced Transmission Access Planning Process

The ETAP Process will evaluate the means to increase transmission access to potential LSE network resources inside and outside the control areas of Duke and Progress.

The ETAP Process will follow the steps outlined in Figure 1. The OSC will approve the scope of the ETAP study (including any changes in the assumptions and study criteria for the studies used in the reliability analysis), oversee the study analysis being coordinated by the PWG, evaluate the study results, and approve the final ETAP study results.

The ETAP Process will begin with the Participants and TAG members proposing scenarios and interfaces to be studied. The proposed scenarios and interfaces will be compiled by the PWG and then evaluated by the OSC to determine which ones will be included for analysis in the current planning cycle. The PWG will coordinate the development of the enhanced transmission access studies based upon the OSC-approved scope and prepare a report which will identify recommended transmission solutions that could increase transmission access.

The final results of the ETAP Process will include the estimated costs and schedules to provide the increased transmission capabilities. The enhanced transmission access study results will be reviewed with the TAG.

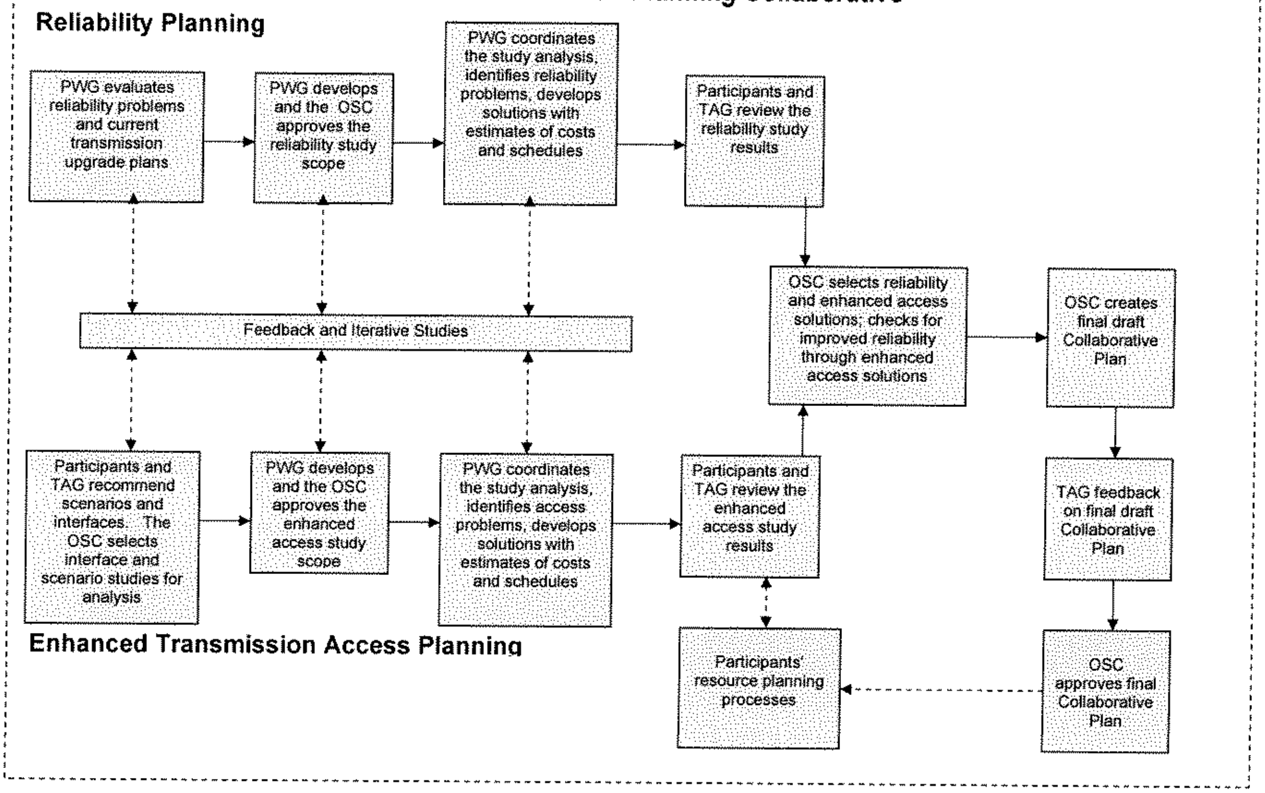
Collaborative Transmission Plan

Once the reliability and ETAP studies are completed, the OSC will evaluate the results and the PWG recommendations to determine if any proposed enhanced transmission access projects will be implemented. If so, the initial reliability study will be modified accordingly. This process will result in a single Collaborative Transmission Plan being developed that appropriately balances the costs, benefits and risks associated with the use of transmission and generation resources. The final plan will be reviewed with the TAG.

The Collaborative Transmission Plan information will be available for Participants to identify any alternative least cost resources to include with their respective Integrated Resource Plans. Other stakeholders can similarly use this information for their resource planning purposes.

Figure 1

North Carolina Transmission Planning Collaborative



Appendix

North Carolina Transmission Planning Collaborative Process

Transmission Planning Study Process - General Scope

The scope of the study processes for both the Reliability Planning and the Enhanced Transmission Access Planning activities are very similar and share many of the same steps such as assumptions, study criteria, methodology, etc.

The typical study process includes the following steps:

1. Assumptions

- Select the study assumptions for the analysis
- The study assumptions normally include the following:
  - Years to study
  - Load levels to be studied (e.g., peak, shoulder and light loads)
  - Load forecasts
  - Resource supply projections
  - Interchange capabilities
  - Firm reservations including TRM / CBM
  - Transmission contingencies
  - Special protection schemes, special operating schemes
  - Financial (e.g., time value of money, financing costs, duration of analysis for present value analyses, etc.)

2. Study Criteria

- Establish the criteria by which the study results will be measured
- The criteria should promote consistency in the planning criteria used by all Participants, while allowing for circumstances that are unique to individual systems
- Typical study criteria involve the following elements:
  - NERC reliability standards
  - SERC Requirements
  - Individual company criteria (voltage, thermal, stability, short circuit, and phase angle)

3. Case Development

- Prepare the base case model
- Develop change case models as required to evaluate different resource supply scenarios

4. Methodology

- Determine the methodologies that will be used to carry out the study
- Determine the specific software programs that will be utilized to perform the analysis

5. Technical Analysis and Study Results

- Perform the study analysis (thermal, voltage, stability and short circuit) and produce the results
  - Study thermal and voltage limits first thermal limits are typically the most difficult to resolve and the most limiting, with voltage issues usually being identified within the same power-flow analyses
  - Study stability and short circuit analysis as needed

6. Assessment and Problem Identification

- Evaluate the results to identify problems / issues. The key questions are:
  - What causes the issues / limits?
  - If the limit were removed or increased, what would the next limit be and what would limit it?

7. Solution Development

- Identify potential solutions to the problems / issues
- Test the effectiveness of the potential solutions through additional studies (thermal, voltage, stability, short circuit) and modify the solutions as necessary such that all study criteria are met
- Perform financial analysis and rough scheduling estimation for each of the proposed transmission solutions (e.g., cost, cash flow, present value)

8. Selection of Preferred Transmission Plan

- Compare alternatives and select the preferred solution alternatives – balancing of cost / benefit / risk

- Select a preferred set of transmission improvements that provides the most reliable and cost effective transmission solution while prudently managing the associated risks

9. Report on the Study Results

- Prepare a report on the results and recommended solutions for the final plan

Scope – Oversight/Steering Committee (OSC)

Purpose

The OSC manages the North Carolina Load Serving Entities' Transmission Planning Process.

The duties of the OSC include the following:

a. for the areas of the State of North Carolina served by Participants, participate in the Reliability Planning Process, and oversee the development of the Enhanced Transmission Access Planning Process;

b. review and approve transmission planning criteria and critical assumptions for the bulk transmission system (i.e., 230 kV and above plus lower voltage facilities that substantively affect the Reliability Planning Process and the Enhanced Transmission Access Planning Process) and, where appropriate, develop and recommend such criteria and assumptions to be used by the Planning Working Group (PWG);

c. promote the application of such planning criteria and/or assumptions within the territories served by the Participants;

d. review and recommend revisions to the transfer capability, transmission reserve margin (TRM) and capacity benefit margin (CBM) criteria and calculations of the investor-owned utilities for consistency with SERC and NERC established criteria as well as good utility practice; recommend transfer capability, TRM and CBM criteria or methodologies which would be applied consistently in the Process, adjusted as appropriate, to accommodate local conditions that merit special consideration;

e. direct the activities of and provide oversight for the PWG;

f. nominate and approve the PWG members. Duke, Progress, ElectriCities and the electric cooperatives shall each nominate at least one and up to three members to the PWG by written notice to the OSC. The OSC shall approve the nominations of the PWG members so long as they materially meet the membership guidelines described in the PWG Scope Document;

g. Select the independent third-party (ITP) consultant and provide oversight direction of the work of the ITP consultant.

h. Develop an annual business plan with an associated budget each year and monitor budget versus actual expenditures throughout the year;

i. Keep the NCUC and non-LSE stakeholders informed concerning the work undertaken by this process;

Subcommittees

The OSC has the authority to form subcommittees as necessary. A scope document for each subcommittee shall be developed and approved by the OSC before the subcommittee begins its work.

The Planning Working Group will be a standing subcommittee that works under the direction of the OSC and will operate within the parameters as identified within its defined scope of work (e.g. its scope document).

Membership

The OSC will consist of eight (8) appointed members plus ex officio members as approved by the OSC. Duke, Progress, ElectriCities and the electric cooperatives shall each appoint two (2) members to the OSC and may each appoint up to two (2) alternate members, all of whose qualifications shall be materially consistent with the guidelines for OSC membership set forth in this section. The electric cooperatives and municipalities' industry segments shall establish rules for electing and replacing its representatives to the OSC consistent with the guidelines provided in this section. The ITP shall be an ex officio member of the OSC.

1. **OSC & ITP Membership Guidelines**

    a) Possess a broad knowledge of transmission grid planning, system operations and resource planning including the following:
        i) Understanding of the process for load serving entities to acquire resources and request proposals for capacity and energy
    b) Broad understanding of electric industry and utility issues
    c) Possess a reasonable understanding of NERC and SERC Planning Standards and good utility practices
    d) Possess a reasonable understanding of FERC regulations and OATT requirements including the following:
        i) FERC Standards of Conduct and Code of Conduct
        ii) Processes for Requesting Transmission Service
        iii) Processes for Requesting Interconnection Service
    e) Possess a reasonable understanding of interregional study processes and results
    f) Possess a reasonable understanding of transfer capability, TRM, CBM principles
    g) Possess a reasonable understanding of the state regulatory process including the following:
        i) Integrated Resource Plans (IRP) process
        ii) Transmission siting approval process
    h) Ability to comply with Standards of Conduct requirements stated in the Participation Agreement/no involvement in market activities
    i) Authority to speak and vote on their company's behalf

2. **Changes in OSC Membership**
    Changes in the OSC membership may be made by the industry segment making the change providing written notification of the change to the OSC chair. The industry segment making the change is responsible for providing a replacement representative from their industry segment.

Membership Terms

An OSC member and their alternate will serve on the OSC until replaced through either the election or appointment process in place for their representative segment or until the member or alternate resigns.

The OSC members shall periodically evaluate the performance of the ITP and shall determine if the contract with the consultant should be renewed or if another consultant should be selected.

OSC Committee Structure

The OSC shall select its chair and vice chair from among its members. The term of office for these positions is two years. The officer positions will be rotated among the two participating investor-owned utilities, electric membership cooperatives and municipalities segments (e.g. officer rotation would occur every two years among the four groups).

Committee Chair

In addition to the duties, rights, and privileges discussed elsewhere in this document, the OSC chair has the responsibility to:

- Provide general supervision of OSC activities
- Schedule all OSC meetings
- Prepare, distribute and post notices of OSC meetings, ensure that meeting minutes are recorded, and distribute meeting minutes, as appropriate
- Develop OSC agendas, and rule on any deviation, addition, or deletion from a published agenda
- Preside at OSC meetings
- Manage the progress of all OSC meetings, including the nature and length of discussion, recognition of speakers, motions, and voting
- Act as spokesperson for the OSC
- Report on OSC activities to the NCUC
- Maintain a record of all OSC proceedings, including responses, voting records and correspondence
- Maintain OSC membership records
- Perform other duties as directed by consensus of the OSC members

Committee Vice Chair

The OSC vice chair shall act as the OSC chair if requested by the chair (for brief periods of time) or if the chair is absent or unable to perform the duties of the chair. If the chair is permanently unable to perform his or her duties, the OSC vice chair shall act as the chair until the OSC selects a new chair.

The vice-chair has the responsibility to:

- Assist the OSC chair
- Perform duties of the OSC chair when the OSC cannot otherwise support these duties

Treasurer

The OSC shall select a Treasurer. The Treasurer may be one of the Participants or this function may be outsourced to a third-party. The OSC is authorized to make changes in the designation of the Treasurer as conditions warrant.

The Treasurer has responsibility to:

- Receive and disburse funds
- Periodically disclose all receipts and disbursements to each Participant

Committee Members

OSC members have the responsibility to:

- Represent their industry segment
- Provide knowledge and expertise representative of their industry segment
- Provide their industry segment feedback on OSC activities
- Respond promptly to all OSC requests for reviews, comments, and voting
- Arrange for alternates to attend and vote at OSC meetings in their absence
- Respond promptly to all requests regarding scheduling OSC meetings

Independent Third-Party (ITP) Consultant

The ITP has the following general responsibilities:

- Serve as a facilitator for the group by working to bring consensus within the group
- Provide transmission planning expertise
- Provide an independent third-party view
- Assist the Chair and Vice-Chair in the performance of their duties as requested

The ITP also provides the leadership role in developing the Enhanced Transmission Access Planning Process, subject to the oversight of the OSC and normal regulatory oversight. In fulfilling these duties the ITC performs the following:

- Develops the mechanisms to solicit and obtain the input of all market participants related to the Enhanced Transmission Access Planning Process.
- Takes all reasonable action to ensure that no member or non-member marketing / brokering organizations receive preferential treatment or achieve competitive advantage through access to transmission-related information.
- Ensures that confidentiality of information and Standards of Conduct requirements are being adhered to within the OSC process.

Meeting Procedures

Meetings

Meetings of the OSC shall be open to OSC members and their alternates, the ITP Member, representatives from voting and authorized non-voting LSEs, approved guests as discussed below, and members of the PWG. Representatives from non-voting LSEs will be authorized to attend these meetings under the following conditions: the LSE serves load within the boundaries of the Participants; the LSE has signed the necessary confidentiality agreements and meets FERC's Code of Conduct requirements; and the LSE has provided appropriate prior notice of its intention of sending a representative(s) to a particular meeting.

Only voting members or their alternates may act on items before the OSC.

In the absence of specific provisions in this scope document, the OSC shall conduct its meetings guided by the most recent edition of *Robert's Rules of Order, Newly Revised*.

Quorum

A quorum requires one voting member or their alternate from each of the industry segments represented in this process (e.g. a total of four voting members must be present with one member being from Duke, Progress, ElectriCities, and the electric cooperatives).

Proxy

If an OSC voting member or their alternate is not able to participate in a particular meeting, the OSC voting member or their alternate may assign their vote to another OSC voting member or their alternate. A written notification of this assignment of the voting privileges must either be provided to the OSC Chair before the meeting or the voting member or alternate that has been given the proxy must provide such written confirmation of this assignment at the beginning of the meeting where the assignment would apply.

Voting

Voting requires a quorum and may take place during formal meetings or may take place through electronic means.

The members of the OSC shall use reasonable good faith efforts to reach decisions via consensus. However, in the event that the OSC is unable to reach a decision by consensus then a decision will be reached by majority vote. When voting is conducted, each of the OSC members (or their designated alternatives) except the ex officio members shall have one vote. In the event of a tie vote, the ITP Member shall be entitled to one vote to break the tie. However, the investor-owned utilities shall not be bound by decisions of the OSC to the extent the investor-owned utilities reasonably determine such decisions, as related to reliability planning, are inconsistent with good utility practice or SERC and NERC established criteria or least-cost integrated resource planning principles. The investor-owned utilities shall each retain decision making authority for such decisions, related to reliability, consistent with their statutory responsibilities for reliability, subject to normal regulatory oversight.

It is anticipated that all parties will abide by the decisions of the OSC. However, any Participant may request that the North Carolina Utilities Commission Public Staff ("Public Staff") render a non-binding opinion with regard to any disputed decision of the OSC and any decision of the investor-owned utility superseding a decision by the OSC ("Disputed Decision"). Should the parties be unable to resolve the Disputed Decision through such facilitation by the Public Staff, any Participant may seek review of the Disputed Decision by any regulatory or judicial body with jurisdiction over the subject matter of the Disputed Decision.

Each individual member's vote for each action taken shall be included in the minutes of each meeting.

Guests

Guests are permitted to attend OSC meetings with prior approval. If a member of the OSC (or their alternate) would like to invite a guest to a particular OSC meeting, the member/alternate shall submit this request to the Chair of the OSC. The OSC member/alternate shall identify the name and his or her affiliation in the request to the OSC Chair. The OSC Chair may approve the request on their own motion or after consultation with the OSC membership.

Scope – Planning Working Group (PWG)

Purpose

The PWG coordinates the development of the transmission studies needed to support the North Carolina Load Serving Entities' Transmission Planning Process.

The duties of the PWG include the following:

a. develop data inputs for the study simulations;

b. determine the appropriate study simulations to be performed;

c. coordinate the execution of the study simulations (the simulations will be performed by the investor-owned utilities with all aspects overseen by the PWG);

d. analyze study results;

e. prepare recommendations and reports;

f. develop input to the OSC's annual business plan and associated budget and monitor PWG related budget versus actual expenditures throughout the year.

Reporting

The Oversight/Steering Committee (OSC) provides direction to the PWG.

Membership

The Planning Working Group (PWG) will consist of up to twelve (12) members. Duke, Progress, ElectriCities and the electric cooperatives shall each nominate at least one and up to three members to the PWG by written notice to the OSC. The OSC shall approve the nominations of the PWG members so long as they materially meet the membership guidelines described in this section. Additionally, the OSC shall appoint a representative from the Independent Third Party (ITP) to the PWG.

1. **PWG & ITP Membership Guidelines**
   a. BS Electrical Engineering (Power System emphasis – PE registration preferred)
   b. Minimum 3 years transmission planning experience, evaluation of system thermal, voltage & stability performance, and solution development
   c. Possess a general knowledge of transmission grid operations, system operations and resource planning
   d. Working knowledge of PSS-E
   e. Working knowledge of MUST
   f. Possess a detailed understanding of NERC and SERC Planning Standards and good utility practice
   g. Possess a reasonable understanding of FERC regulations and OATT requirements
   h. Understanding of the transmission system model development process
   i. Possess a reasonable understanding of interregional study processes and results
   j. Understanding of transfer capability, TTC, TRM, CBM principles

k. Ability to comply with Standards of Conduct requirements stated in the Participation Agreement/no involvement in market activities
l. Possess a reasonable understanding of the state regulatory process.

2. **Changes in PWG Membership**
Changes in the PWG membership may be made by the industry segment making the change providing written notification of the proposed change to the OSC Chair. The industry segment making the change is responsible for providing a replacement representative from their industry segment. The OSC Chair will seek approval for the change from the OSC members, who will approve the change as long as the replacement representative materially meets the PWG membership guidelines.

Membership Terms
A PWG member will serve on the PWG until either they are replaced by their representative segment or until the member resigns.

PWG Committee Structure

The PWG shall select its chair and vice chair from among its members. The term of office for these positions is two years.

Committee Chair
In addition to the duties, rights, and privileges discussed elsewhere in this document, the PWG chair has the responsibility to:

- Provide general supervision of PWG activities
- Schedule all PWG meetings
- Prepare, distribute and post notices of PWG meetings, ensure that meeting minutes are recorded, and distribute meeting minutes, as appropriate
- Develop PWG agendas, and rule on any deviation, addition, or deletion from a published agenda
- Preside at PWG meetings
- Manage the progress of all PWG meetings, including the nature and length of discussion and recognition of speakers
- Act as the interface to the OSC
- Maintain a record of all PWG proceedings, including responses and correspondence
- Maintain PWG membership records
- Perform other duties as directed by consensus of the PWG members

Committee Vice Chair
The PWG vice chair shall act as the PWG chair if requested by the chair (for brief periods of time) or if the chair is absent or unable to perform the duties of the chair. If the chair is permanently unable to perform his or her duties, the PWG vice chair shall act as the chair until the PWG selects a new chair.

The vice chair has the responsibility to:

- Assist the PWG chair
- Perform duties of the PWG chair when the PWG cannot otherwise support these duties

Scope – Planning Working Group (PWG)

Committee Members
PWG members have the responsibility to:

- Represent their industry segment
- Provide knowledge and expertise representative of their industry segment
- Provide their industry segment feedback on PWG activities
- Respond promptly to all PWG requests for reviews and comments
- Respond promptly to all requests regarding scheduling PWG meetings

Independent Third-Party (ITP) Consultant
The ITP has the following general responsibilities:

- Serve as a facilitator for the group by working to bring consensus within the group
- Provide transmission planning expertise
- Provide an independent third-party view
- Assist the chair and vice chair in the performance of their duties as requested

The ITP also provides the leadership role in developing the Enhanced Transmission Access Planning Process, subject to the oversight of the OSC and normal regulatory oversight. In fulfilling these duties, the ITP performs the following:

- Develops the mechanisms to solicit and obtain the input of all market participants related to the Enhanced Transmission Access Process.
- Takes all reasonable action to ensure that no member or non-member marketing/brokering organizations receive preferential treatment or achieve competitive advantage through access to transmission-related information.
- Ensures that confidentiality of information and Standards of Conduct requirements are being adhered to within the PWG process.

Meeting Procedures

Meetings
Meetings of the PWG shall be open to PWG members, the ITP Member and OSC members and their alternates. After consulting with the PWG members, the Chair of the PWG has the discretion to invite guests to attend the PWG meeting (or a portion of the meeting as appropriate) provided that those guests execute a confidentiality agreement that is consistent with the confidentially requirements and the Standards of Conduct requirements of the Participation Agreement.

The PWG shall use reasonable good faith efforts to reach decisions via consensus. However, in the event the PWG is unable to reach a decision by consensus, the decision will be referred to the OSC for resolution.

In the absence of specific provisions in this scope document, the PWG shall conduct its meetings guided by the most recent edition of *Robert's Rules of Order, Newly Revised.*

Quorum
A quorum requires at least one member from each of the industry segments represented in this process (e.g. a total of four members must be present with one member being from Duke, Progress, ElectriCities, and the electric cooperatives).

North Carolina Transmission Planning Collaborative

Transmission Advisory Group

Scope

Purpose

The Transmission Advisory Group (TAG) is formed from the North Carolina Load Serving Entities' Transmission Planning Participation Agreement ("Agreement") among the following Participants: Duke Power, Progress Energy Carolinas, Inc., North Carolina Electric Membership Corporation, and ElectriCities of North Carolina, Inc. The purpose of the TAG is to provide advice and recommendations to the Participants which will aid in the development of a single coordinated transmission plan for the respective service territories of these Participants in North Carolina.

Responsibilities

The TAG is responsible for working with the Participants to develop a transmission planning process that results in a single coordinated transmission plan which reliably and efficiently meets the needs of the electric consumers in North Carolina. The duties of this group include:

1. Adhere to the intent of the FERC Standards of Conduct requirements in all discussions.
2. Participate in the TAG meetings in a constructive and professional manner.
3. Provide timely input on the issues associated with the development of the transmission planning process.
4. Provide advice and recommendations to the Oversight Steering Committee of the Participants on the transmission plan results.

Membership

The TAG membership is open to all parties interested in the development of a coordinated transmission plan across the respective service territories of the Participants in North Carolina.

Meeting Procedures

Meeting Chair

The independent third-party consultant will chair the TAG meetings and serve as a facilitator for the group by working to bring consensus within the group. In addition, the duties of the independent third-party consultant include:

1. Developing mechanisms to solicit and obtain the input of all market participants related to transmission planning options.
2. Taking all reasonable action to ensure that no marketing / brokering organizations receive preferential treatment or achieve competitive advantage through the distribution of any transmission-related information in the TAG.
3. Ensuring that confidentiality of information and Standards of Conduct requirements are being adhered to within the TAG process.
4. Ensuring that TAG meeting notes are taken and meeting highlights are posted for the information of the participants after all TAG meetings.

Meeting Procedures

Meetings

Meetings of the TAG shall be open to all parties interested in the development of a coordinated transmission plan across the respective service territories of the Participants in North Carolina. There are no restrictions on the number of people attending TAG meetings from any organization.

Quorum

Since membership is open to all interested parties, there are no quorum requirements for TAG meetings.

Voting

In attempting to resolve any issue, the goal is for the TAG to develop consensus solutions. Non-binding straw votes may be taken by the TAG chair on issues or discussion items in order to get the sense of the group and attempting to achieve consensus. Only one vote for each organization participating in the TAG meeting will be allowed. Only organizations attending the meeting will be allowed to participate in the voting. No proxy votes will be allowed.

Meeting Protocol

In the absence of specific provisions in this document, the TAG shall conduct its meetings guided by the most recent edition of *Robert's Rules of Order, Newly Revised.*

NCTPC TRANSMISSION COST ALLOCATION WHITEPAPER
FINAL – September 6, 2007

I. COST ALLOCATION REQUIREMENTS OF ORDER NO. 890

In Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service*, the Federal Energy Regulatory Commission (Commission or FERC) provided the following guidance regarding transmission cost allocation:

1. Transmission Providers must develop cost allocation principles that apply to regional projects that do not fit under the existing OATT cost allocation structures.

2. Each regional transmission planning process can develop its own cost allocation criteria and solution as long as it follows these three general principles:

   a) Fairly assigns costs to those who caused the problem as well as to those who will benefit from the solution.

   b) Provides adequate incentives to the Transmission Providers to construct.

   c) Generally is supported by the states and participants across the planning region.

3. Each planning process must address the cost allocation principle upfront.

II. SUMMARY OF COST ALLOCATION PROPOSALS

The NCTPC Participants have developed an "avoided cost" cost allocation methodology that applies to reliability projects where there is a demonstration that a regional transmission solution and regional approach to cost allocation results in cost savings. Such "Regional Reliability Projects" are projects that are proposed in lieu of "Reliability Projects," which are projects required to preserve system reliability. The NCTPC Participants also have developed a "requestor pays" cost allocation methodology that applies to Regional Economic Transmission Paths ("RETPs") which improve economic power transfers between control areas. These two cost allocation methodologies apply to projects that are within the scope of the planning performed by the NCTPC, which focuses on the bulk transmission system (i.e., 230 kV and above facilities and lower-voltage facilities that substantively affect the Reliability Planning Process and Enhanced Transmission Access Planning Process).

Please note that for purposes of the following cost allocation discussion, all monetary amounts are net present value (NPV) amounts, unless otherwise noted.

III. OATT COST ALLOCATION FOR RELIABILITY PROJECTS

A transmission system is a complex system where each Transmission Provider's system reliability is also dependent upon its neighboring transmission systems. In recognition of this interdependence, reliability issues affecting one transmission system may require transmission upgrades on an adjacent transmission system. In addition, the reliability needs of a transmission system will change over time as a result of network and native load growth, the addition of new generation resources, the retirement of generation, and the provision of additional long-term firm point-to-point transmission service. FERC's OATT requires that Transmission Providers construct the facilities necessary to maintain reliable service in light of these needs. Any such facilities that are integrated network transmission facilities are denominated "Reliability Projects" herein. The various types of "Reliability Projects" are described briefly below.

A. Generation Interconnection Network Upgrade Projects

Generation interconnection network upgrade projects are Reliability Projects that consist of the integrated transmission facilities required to reliably connect a new generating plant into the transmission system and reliably dispatch its output into the network. For these projects, the upfront costs are allocated to the generation developer in accordance with the OATT, subject to crediting when transmission service is obtained from the relevant resource.

B. Transmission Service Projects

It is each Transmission Provider's responsibility to plan and operate a reliable transmission system in accordance with NERC and its applicable regional reliability standards. Reliability Projects that are required to provide transmission service fall into two categories -- Existing Transmission Service Projects and New Transmission Service Projects.

Existing Transmission Service Projects include the transmission facilities required for maintaining system reliability to serve network and native load and to meet existing firm point-to-point service obligations. As load grows and the existing transmission facilities age, new projects and upgrades may be necessary to ensure reliable service. New Transmission Service Projects include facilities required to fulfill new long-term firm point-to-point transmission requests and projects related to requests to designate new Network Resources.

Currently, for both New and Existing Transmission Service Projects, the Transmission Provider is responsible for incurring those transmission costs and recovering its costs through its transmission revenue requirement under its existing OATT rate structures. For Network Customers, these transmission costs typically are allocated to all Network Load on a load-ratio share. Point-to-point customers pay the higher of a rolled-in rate or an incremental rate.

IV. "AVOIDED COST" COST ALLOCATION METHODOLOGY FOR RELIABILITY PROJECTS THAT QUALIFY AS "REGIONAL RELIABILITY PROJECTS"

A. Identification of Regional Reliability Projects Subject to Avoided-Cost Cost Allocation

While individual Reliability Projects may arguably (and alternately) benefit customers on a neighboring system or may benefit some customers on one system more than others on the same system, the NCTPC believes that Reliability Projects generally benefit all customers within the relevant service territory of the Transmission Provider and that therefore the costs should be allocated in accordance with the "or" pricing policy currently included in the Commission's *pro forma* OATT. The NCTPC, however, recognizes an exception to the general rule that the costs of projects needed for reliability should be allocated to a particular Transmission Provider's customers. Specifically, Regional Reliability Projects, which can be identified through the NCTPC's regional planning process, should have their costs allocated on an avoided-cost basis.

The NCTPC Planning Process results in a set of projects that satisfy the reliability criteria of the Transmission Providers who are a party to the NCTPC agreement (i.e., Reliability Projects). Through this process, a project may be identified that meets a reliability need in a more cost-effective manner than if each Transmission Provider were only considering projects on its system to meet its reliability criteria. For purposes of eligibility, a Regional Reliability Project can be defined as any reliability project that requires an upgrade to a Transmission Provider's system that would not have otherwise been made at that time based upon the reliability needs of the Transmission Provider. For example, assume that there is a reliability issue on the system of Duke, and this issue can be addressed by: Option 1 - a project that consists of upgrades solely on the system of Duke; Option 2 - a project that consists of upgrades solely on the system of Progress; or Option 3 - a project that encompasses upgrades on both the Duke and Progress systems. Options (2) and (3) would qualify as Regional Reliability Projects, if they are lower cost than Option (1). In both cases, there is an upgrade that is not needed to maintain reliability on the transmission system of at least one of the Transmission Provider's whose system is being upgraded. In addition, if accelerating a Reliability Project on the Progress system results in the elimination of an upgrade on the Duke system, the cost of the acceleration will be designated a Regional Reliability Project. A Regional Reliability Project must have a cost of at least $1 million to be subject to the cost allocation proposal described below. The costs of a Regional Reliability Project with a cost of less than $1 million would be borne by each Transmission Provider based on the costs incurred on its system.

B. Avoided Cost Methodology

As noted, unless a Regional Reliability Project is determined by the NCTPC to be the most cost-effective solution to a reliability need, it will not be selected to be included in the Plan of the NCTPC. But, if a Regional Reliability Project is included, it will have its costs allocated based on an avoided cost approach, whereby each Transmission Provider looks at the next-best approach to maintaining reliable service and shares the savings on a pro-rata basis. These cost responsibility determinations will then be reflected in transmission rates. Each Transmission Provider will be reimbursed for its investment for the Regional Reliability Project based on a transmission levelized fixed charge rate filed with FERC. Where practical, Regional Reliability Projects may be grouped to net out allocations across Transmission Provider borders.

C. Example 1: A Regional Reliability Project on system of one Transmission Provider solves reliability issue on system of other Transmission Provider.

(1) Transmission Provider	(2) Cost to Meet Reliability Needs on a Stand Alone Basis (MM)	(3) Cost of Regional Reliability Project (MM)	(4) Avoided Transmission Project Cost (MM)	(5) Costs to Meet Reliability Needs on a Regional Basis (MM) (2) + (3) - (4) = (5)
Duke	$500	0	$50	$450
Progress	$400	$30	0	$430
Total	**$900**	**$30**	**$50**	**$880**

In this example, Duke needs to spend $500 million to meet all of its Reliability Project needs, assuming it does not have the option of meeting its reliability need with a project on system of Progress. The $500 million includes $50 million for a Reliability Project on its system. But, by Progress spending $30 million on a Regional Reliability Project, Duke could avoid building that $50 million project. Progress needs to spend $400 million for Reliability Projects on its system to meet its needs. Progress also will spend an additional $30 million on its system to meet the Duke reliability need.

The avoided cost methodology for allocating cost responsibility would apply as follows:

(Duke's Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($50 million/$50 million) * $30 million = $30 million

(Progress Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($0 million/$50 million) * $30 million = $0

In sum, from a cost incurrence perspective, Duke spends $450 million and Progress spends $430 million. But, from a cost responsibility perspective Duke is allocated $30 million of Progress' costs.

D. Example 2: A Regional Reliability Project on system of two Transmission Providers solves reliability issue on system of one Transmission Provider.

(1) Transmission Provider	(2) Cost to Meet Reliability Needs on a Stand Alone Basis (MM)	(3) Cost of Regional Reliability Project (MM)	(4) Avoided Transmission Project Cost (MM)	(5) Costs to Meet Reliability Needs on a Regional Basis (MM) (2) + (3) - (4) = (5)
Duke	$500	$20	$50	$470
Progress	$400	$10	0	$410
Total	**$900**	**$30**	**$50**	**$880**

In this example, Duke needs to spend $500 million to meet all of its Reliability Project needs, assuming it does not have the option of meeting its reliability need with a project on system of Progress. The $500 million includes $50 million for a Reliability Project on its system. But, by Progress spending $10 million on a Regional Reliability Project and Duke spending $20 million on the same project, Duke could avoid building that $50 million project. Progress needs to spend $400 million for Reliability Projects on its system to meet its needs. Progress also will spend an additional $10 million on its system to meet the Duke reliability need.

The avoided cost methodology for allocating cost responsibility would apply as follows:

(Duke's Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($50 million/$50 million) * $30 million = $30 million

(Progress Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($0 million/$50 million) * $30 million = $0

In sum, from a cost incurrence perspective, Duke spends $470 million and Progress spends $410 million. But, from a cost responsibility perspective Duke is allocated $10 million of Progress' costs.

E. Example 3: A Regional Reliability Project on system of two Transmission Providers solves reliability issues on systems of both Transmission Providers.

(1) Transmission Provider	(2) Cost to Meet Reliability Needs on a Stand Alone Basis (MM)	(3) Cost of Regional Reliability Project (MM)	(4) Avoided Transmission Project Cost (MM)	(5) Costs to Meet Reliability Needs on a Regional Basis (MM) (2) + (3) - (4) = (5)
Duke	$500	$20	$50	$470
Progress	$400	$10	$5	$405
Total	**$900**	**$30**	**$55**	**$875**

In this example, Duke needs to spend $500 million to meet all of its Reliability Project needs, assuming it does not have the option of meeting its reliability need with a project on system of Progress. The $500 million includes $50 million for a Reliability Project on its system. But, by Progress spending $10 million on a Regional Reliability Project and Duke spending $20 million on the same project, Duke could avoid building that $50 million project. Progress needs to spend $400 million for Reliability Projects on its system to meet its needs. But, as a result of the same Regional Reliability Project, Progress can avoid spending $5 million to meet its own reliability needs.

The avoided cost methodology for allocating cost responsibility would apply as follows:

(Duke's Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($50 million/$55 million) * $30 million = $27.3 million

(Progress Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($5 million/$55 million) * $30 million = $2.7 million

In sum, from a cost incurrence perspective, Duke spends $470 million and Progress spends $405 million. But, from a cost responsibility perspective Duke is allocated $7.3 million of Progress' costs.

F. Example 4: Accelerating a Reliability Project on one Transmission Providers' system solves reliability issues on another Transmission Providers' system.

(1) Transmission Provider	(2) Cost to Meet Reliability Needs on a Stand Alone Basis (MM)	(3) Cost of Regional Reliability Project (MM) (Cost of Acceleration)	(4) Avoided Transmission Project Cost (MM)	(5) Costs to Meet Reliability Needs on a Regional Basis (MM) (2) + (3) - (4) = (5)
Duke	$500	$20	$0	$520
Progress	$400	$0	$50	$350
Total	**$900**	**$20**	**$55**	**$870**

In this example, Duke needs to spend $500 million to meet all of its Reliability Project needs. The $500 million includes $120 million for a Reliability Project on its system. Progress needs to spend $400 million to meet all of its Reliability Project needs, including $50 million for a Reliability Project on its system. However, if Duke accelerates the $120 million project by 5 years, Progress could avoid building its $50 million project. The cost of accelerating the Reliability Project by 5 years is a lower cost solution and thus is designated as a Regional Reliability Project. The cost of the Regional Reliability Project is the cost of the 5-year acceleration of the $120 million Reliability Project, or $20 million, which is calculated by subtracting the NPV of completing the project in 5 years from the NPV of completing the project in 10 years.

The avoided cost methodology for allocating cost responsibility would apply as follows:

(Duke's Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($0 million/$50 million) * $20 million = $0

(Progress Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($50 million/$50 million) * $20 million = $20 million

In sum, from a cost incurrence perspective, Duke spends $520 million and Progress spends $350 million. But, from a cost responsibility perspective Progress is allocated $20 million of Duke's costs.

G. Regional Reliability Projects that Include Transmission Providers Outside the NCTPC Footprint

If a Regional Reliability Project that is suitable for this alternate cost allocation approach involves a Transmission System(s) outside the NCTPC, the costs should be fairly allocated among the affected Transmission Providers based on good-faith negotiation among the parties involved. It would be the intent of the NCTPC Participants that the "avoided cost" approach outlined above be used as a starting point in the negotiations. The resulting transmission costs and the associated revenue requirements of each Transmission Provider will be recovered through their respective existing rate structures at the time. In the event that the affected Transmission Providers are unable to reach a negotiated solution then the NCTPC would propose that the parties utilize the Commission's Dispute Resolution Service to settle any issues.

V. "REQUESTOR PAYS" COST ALLOCATION METHODOLOGY FOR PROJECTS ASSOCIATED WITH REGIONAL ECONOMIC TRANMISSION PATHS ("RETPs")

A. Background

In Order 890, FERC asked Transmission Providers to develop a cost allocation methodology intended to apply to economic projects that do not fit under the existing OATT structure and that will reduce congestion or enable groups of customers to access new generation. The NCTPC is not proposing a cost allocation methodology for "economic projects" within a single Transmission Provider's system because there are no internal constraints within the Duke or Progress systems as demonstrated by the fact that ATC values are posted only at their interfaces with other control areas. That is, there is no need for a cost allocation methodology that would apply to projects that relieve constraints within a single Transmission Provider's control area. Thus, the relevant "economic projects" are those projects required to permit Transmission Providers to ensure that point-to-point (PTP) transmission service can be provided over the systems of two or more Transmission Providers.

The NCTPC has designated "projects" that would ensure that PTP service can be provided over the Duke and/or Progress systems as Regional Economic Transmission Paths ("RETPs"). NCTPC stakeholders will be permitted to propose that RETPs be created and the costs of the projects necessary to create such RETPs will be subject to the "requestor pays" cost allocation methodology described herein. The creation of an RETP would permit energy to be transferred on a PTP basis from an interface (or a Point of Receipt) on one Transmission Provider's system to an interface on another Transmission Provider's system (or a Point of Delivery) for a specific period of time. In the discussion below, the NCTPC Participants define how this methodology could be applied in the NCTPC.

As just noted, RETPs are defined as multi-Transmission Provider point-to-point transmission paths. But, NCTPC cannot impose the RETP concept and requestor-pays cost allocation methodology discussed below on Transmission Providers outside the NCTPC footprint. NCTPC will share this proposal with other Transmission Providers with the goal of having it adopted on a broader basis. Other Transmission Providers and inter-regional processes outside the NCTPC footprint, however, may develop their own approaches, which may or may not be able to accommodate the NCTPC approach.

The NCTPC Participants are expecting to actively participate in a coordinated effort that will be referred to herein as the Inter-Regional Planning Process (IRPP). This effort is in the very early stages of development. It is thus unlikely any regional economic cost allocation approach will be finalized prior to the December 7th Attachment K filings. If a process cannot be formalized by such date, the proposal below, as it evolves through NCTPC stakeholder input, will apply to the NCTPC. If Transmission Providers outside the NCTPC do not adopt the RETP concept and/or seek to apply other cost allocation mechanisms, it should be possible for Duke and Progress to coordinate with other Transmission Providers and study and create paths that are larger than the NCTPC footprint.

In sum, until the RETP concept is reviewed and considered by others outside the NCTPC, it should be understood that only the NCTPC Transmission Providers are committed to the further development of the conceptual framework for this process and cost-allocation methodology described below.

B. Identification and Initial Study of RETPs

It is envisioned that stakeholders will identify RETPs that they would like studied and that they would do so through the relevant stakeholder process. If an RETP is limited to the NCTPC footprint, it would be brought to the TAG. If the IRPP adopts the RETP or a similar concept, the IRPP stakeholder process would have a similar process for the identification of projects that would impact that regional footprint.

There would be a need for an Initial Study of an RETP ("Initial RETP Study"). If a proposed regional path would impact Transmission Providers outside the NCTPC that are not willing to participate in a uniform RETP process, there will need to be coordination of such an initial study with other transmission neighbors.. Because it cannot be predicted which Transmission Providers outside the NCTPC might consider the RETP approach, the discussions herein of the study process, Open Season, and cost allocation largely assume that the RETP concept will spread beyond the NCTPC. This assumption is merely for convenience.

The Initial RETP Study would identify any transmission system problems/limitations related to all Transmission Providers along the RETP providing PTP service and would identify the transmission solutions/upgrades that would be needed to accommodate the RETP. An RETP would be evaluated in the Initial RETP Study as if it was a request for PTP transmission service from a source control area (Point of Receipt) to a sink control area (Point of Delivery) over a specific period of time (the stakeholders requesting the study would determine the time period). The Point of Receipt and Point of Delivery can be interfaces. (If those points are interfaces, entities seeking to use the RETP would have to separately request transmission service, if necessary, to move power from their generating resources to the interfaces. Given the unconstrained nature of the Transmission Systems in the NCTPC, such service should typically be available.)

The Initial RETP Study would only provide preliminary information on the projected cost and scope of the facilities that would be needed to create the RETP, and the time it would take to complete the RETP. Each Transmission Provider along the RETP would identify its own estimated costs. The reason that the study must be preliminary in nature is that the study request will not be treated as if it is a queued transmission service request; later transmission requests may impact the cost estimates. It would be premature to "queue" the proposed RETP (thus potentially taking existing ATC "off the market"), until the decision to hold an Open Season is made.

Once the Initial RETP Study is complete, the relevant stakeholder processes would determine if there is sufficient interest in the project to move the RETP from the "initial study" mode to the establishment of an "Open Season" for the RETP. This decision would have to be carefully considered by the stakeholders, as it could result in ATC being made unavailable for what may be several months. For example, assume an RETP is proposed as a 1000 MW path from an interface on the Florida-Southern border to an interface on the Duke-PJM border that would be operational in 2015. Assume further that on the Duke system, 300 MW of existing ATC is available in 2015, but that Duke would have to upgrade its system to ensure the remaining 700 MW of the 1000 MW path. Once the Open Season commences, Duke will assume in reviewing new transmission service requests (and rollover rights of such new requests) that the 300 MW of ATC is no longer available in 2015.

C. Open Season for RETPs

After an RETP has been identified, the Initial RETP Study completed, and it is determined by the relevant stakeholder body that there is sufficient interest in moving this project to the next level of consideration; an "Open Season" will be established to determine if there is sufficient interest in funding the upgrades necessary to create the RETP.

All Transmission Providers impacted by the RETP would establish the same "Open Season" for the RETP. The Open Season will have a similar impact to someone queuing a PTP service request for the entire proposed MW of the RETP from the source control area to the sink control area for the relevant time period. To the extent that there is ATC available that will form part of the new RETP, this ATC would be available only to Open Season participants, not to Transmission Customers who hold transmission queue positions based on service requests submitted after the start date of the Open Season. Thus, returning to the example of the new 1000 MW Florida-PJM RETP, to the extent Duke planned to use 300 MW of ATC that were otherwise available in 2015, Duke would consider this 300 MW unavailable to requestors in its transmission queue that post-dated the Open Season. This approach would be important to ensure that Transmission Customers who were familiar with the RETPs that were under consideration would not be able to cherry-pick PTP transmission reservations along the path of an RETP. If the Open Season resulted in the RETP not going forward, the 300 MW of ATC would again be available to those that entered the transmission queue after the date of the Open Season.

During this Open Season all potential Transmission Customers would have a 30 to 60-day window to put in their request to subscribe to all or a portion of the MW of service being made available along the RETP. The OSC with input from the TAG would determine the length of the Open Season. If the RETP was not fully subscribed (i.e., 100% of the MW reserved), the Open Season will be extended by another 30 days if there is a subscription to 80% of the MW or higher. If the RETP was oversubscribed, then the RETP subscription would be distributed in a *pro rata* fashion. When oversubscription occurs, the participating Transmission Customers will be notified. All of these Transmission Customers will be given the opportunity to proceed with a firm PTP transmission subscription based on these pro rata allocations of the transmission service. However, one or more of the participating Transmission Customers may choose not to move forward due to their determination that fulfilling only a portion of their desired transmission allocation would not meet their business needs. To accommodate this situation, a "reallocation window" would be established to allow for the Transmission Customer to withdraw or adjust their transmission allocation requests. All Transmission Customers are eligible to participate in this reallocation window. Since this is an iteration on the first Open Season for the same project, the reallocation window would be no greater than 30 days. All such processes will be open and transparent, which will allow Transmission Customers to work among themselves to determine how they can get the RETPs built.

Example:

- RETP was identified as a transmission path between Entergy and PJM with a 500 MW capacity.
- Through the RETP Initial Study, all of the Transmission Providers identify their estimated costs and potential rate impacts on transmission service so that Transmission Customers can evaluate the financial impact of subscribing to the RETP.
- Potential Transmission Customers are given a 60 day window to identify their desire to be a subscriber for this RETP.
- Open Season Results:
  - Sufficient Subscription – Case 1. Transmission Customer 1 – Willing to subscribe for entire amount – 500 MW of PTP service. Sufficient subscription, RETP moves forward.
  - Sufficient Subscription – Case 2. Transmission Customer 1 – Willing to subscribe for 250 MW. Transmission Customer 2 – Willing to subscribe for 250 MW of PTP service. Sufficient subscription, RETP moves forward.
  - Insufficient Subscription – Case 1. Transmission Customer 1 – Willing to subscribe for 250 MW. No other Transmission Customers agree to subscribe to the RETP, therefore RETP does not move forward.

- Insufficient Subscription – Case 2. Transmission Customer 1 – Willing to subscribe for 450 MW. No other Transmission Customers agree to subscribe to the RETP. Reallocation window of 30 days because RETP 90% subscribed (greater than 80% threshold).

  - Case 2.a – No one responds to reallocation window:

    - Transmission Customer 1 is offered the opportunity to subscribe to the other 50 MW (i.e., pay the full price of the upgrade). If the customer accepts, the RETP goes forward. If the customer does not accept, the RETP does not go forward.

  - Case 2.b – Transmission Customer 2 is willing to subscribe to 30 MW of the 50 unsubscribed MW.

    - Transmission Customer 1 and 2 are offered the opportunity to subscribe to the other 20 MW on a pro rata basis (Transmission Customer 1 would receive an additional 19 MW; Transmission Customer 2 would receive an additional 1 MW). If the Customers accept, the RETP goes forward. If the customers do not accept, the RETP does not go forward.

  - Case 2.c – Transmission Customer 2 is willing to subscribe to 30 MW and Transmission Customer 3 is willing to subscribe to 30 MW

    - The Customers are offered a pro rata share (25 MW each). If the Customers accept, the RETP goes forward. If the customers do not accept, the RETP does not go forward.

- Over-subscription.

  <u>Initial Open Season Iteration</u>: Transmission Customer 1 – Willing to subscribe for 250 MW. Transmission Customer 2 – Willing to subscribe for 250 MW. Transmission Customer 3 – Willing to subscribe for 250 MW. Pro-rata subscription is provided and Transmission Customers 1, 2 and 3 all get 167 MW. Transmission Customers would be free to negotiate with each other on a different

allocation. Transmission Customers 1, 2 and 3 are given the opportunity to move forward with this RETP at their prorated allocation levels. If one or more of these customers choose not to move forward, then the reallocation window would be started.

Reallocation window: Potential Transmission Customers are given a 30-day window to identify their desire to be a participant in this iteration. Transmission Customers 1 and 2 decide to move forward, even if limited to 167 MW; Transmission Customer 3 decides to withdraw. The 167 MW of Transmission Customer 3's is "re-opened." Transmission Customer 4 decides to enter the Open Season and:

- Transmission Customer 1 – Willing to subscribe for 83 MW (i.e., the 83 MW it did not get in first Open Season).
- Transmission Customer 2 – Willing to subscribe for 167 MW (i.e., the 83 MW it did not get in first Open Season plus additional 84 MW).
- Transmission Customer 4 – Willing to subscribe for 167 MW.
- Pro-rata subscription is provided as follows (rounded to whole MW):
  - Transmission Customers 1 – 33 MW
  - Transmission Customer 2 – 67 MW
  - Transmission Customer 4 – 67 MW
  - Transmission Customers would be free to negotiate with each other on a different allocation.
- Transmission Customers 1, 2 and 4 are given the opportunity to move forward with this RETP at their pro-rated allocation levels. If all of these Transmission Customers agree to move forward with this RETP at their pro-rated amounts then the project moves forward with firm PTP transmission reservations being granted at the allocated levels. If one or more of these customers choose not to move forward, then the RETP will not move forward.

If an RETP is fully subscribed, the more detailed studies, i.e., a Facilities Study will be performed by each impacted Transmission Provider that must provide service along the RETP.

Once the Facilities Study is complete, the Transmission Customers may opt out of their subscriptions if such notice is received within 15 days of the completed study. If Transmission Customers whose initial requests were only filled pro rata are willing to step in, they will have first priority to any capacity made available (on a pro-rata basis as necessary). If the RETP is not fully subscribed after such step, another 30-day iteration should be held if to determine if other entities are willing to fill the subscription. If not, the RETP will not move forward.

D. "Requestor Pays" Cost Allocation Approach

"Requestor Pays" is the proposed approach to cost allocation under which the Transmission Customer(s) that are subscribing to the RETP would provide the up-front funding of any transmission construction that was required to ensure that the path was available for the relevant time period. These "requestor(s)" would be the Transmission Customers that were awarded the MW as a result of the successful subscription during the Open Season process. Four examples are provided in Section V.G. At least on the Duke and Progress systems, subscribers would pay for firm PTP transmission service on each Transmission System along the path of the RETP at the embedded cost rate. If the RETP concept is adopted beyond the NCTPC, other Transmission Providers could propose alternate cost allocation approaches for their segments of the RETP, although such approaches would have to be consistent with the NCTPC approach.

On the Duke and/or Progress systems, the Transmission Customer would receive a levelized repayment of this initial funding amount from Duke and/or Progress in the form of monthly transmission credits over a maximum 20-year period. The Transmission Providers will be permitted to work with the Transmission Customers to provide shorter or different crediting. As credits are paid, Duke and Progress could have the opportunity to include the costs of upgrades that were needed for the RETP in transmission rates, similar to the Generator Interconnection pricing/rate approach.

Transmission projects that are constructed for particular transmission expansion needs typically results in additional "head-room" being created in the transmission system as a result of the transmission construction. There is no attempt within this requestor pays cost allocation methodology to provide compensation to the "funders" of the RETPs for the head-room that would be created on the Transmission System. This is comparable and equitable to how other transmission expansion projects are handled within the normal transmission planning environment. Moreover, there will be situations in which one particular Transmission Provider along the RETP evaluation does not have to incur transmission construction in order to satisfy the provision of service on its portion of the RETP. In that situation, the Transmission Customer would not be assessed any transmission expansion cost for that particular portion of the path. In those situations, the Transmission Customer would be benefiting from some of the "head-room" that was created in the system as a result of other transmission projects. Hence this treatment of the potential "head-room" created by RETPs is comparable and equitable to other transmission expansion performed by the Transmission Providers.

E. Adjustments to Costs to Reflect Impacts of RETPs on Reliability Projects Included in Transmission Plans

The total project cost for the transmission expansion required due to an RETP will be adjusted to provide compensation for the positive impacts that the RETP would provide, given the existing Collaborative Transmission Plan. Specifically, if the RETP resulted in the delay of Reliability Projects, the net present value of this would be computed and subtracted from the net present value of the computed total project cost for the transmission expansion. For example, if the cost for the RETP on the system of one Transmission Provider was computed to be $100 million, but this project would eliminate the need for a $25 million Reliability Project, then this positive impact would be subtracted from the total estimated cost of the RETP and requestor(s) would be assessed a transmission expansion funding amount equivalent to $75 million NPV ($100 million - $25 million).

F. Additional Coordination Needed

In order to implement this cost allocation proposal, coordination of RETPs studies is necessary. The NCTPC expects that the IRPP would address this for the southern Transmission Provider neighbors. Additional coordination would be needed with PJM, as the PJM system adjoins the transmission systems of Duke and Progress.

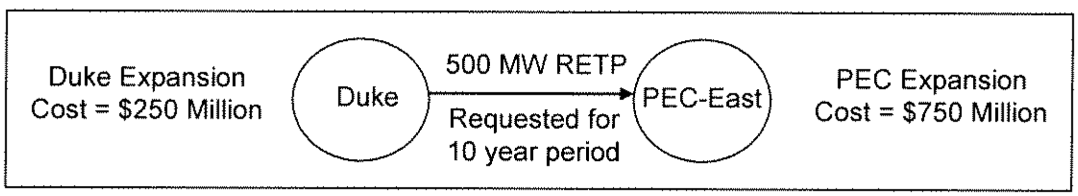
Also, additional coordination would need to be provided to support a single "Open Season" for an RETP. The Transmission Providers would need to develop a coordination procedure that could be utilized each time an Open Season was needed for a particular RETP. The coordination procedure would define how the Open Season would be conducted and coordinated This level of coordination is needed to ensure that the impacted Transmission Providers are all evaluating the RETP within the same timeframe which is very important due to the impact that these projects could have on other transmission requests that would be in the transmission queue.

G. Examples

Four examples are provided to show how the NCTPC would be utilized in the following scenarios: RETPs that flow "into" the NCTPC footprint; RETPs that flow "out of" the NCTPC footprint; RETPs that "pass-through" the NCTPC footprint; and RETPs that are contained totally "within" the NCTPC footprint. All of these examples assume that all impacted Transmission Providers have agreed to use the Open Season process for RETPs projects. The examples described below build on each other, so the order of the examples is as follows:

1. Example 1 – "Within NCTPC" – Duke to PEC-East – Increase interface by 500 MW
2. Example 2 – "Into NCTPC" – Into PEC-East – Increase PEC-East interface with SCE&G by 500 MW (uses info from Example 1)
3. Example 3 – "Out of NCTPC" – Duke to PJM of 500 MW (uses info from Example 1)
4. Example 4 – "Through NCTPC" – Entergy to PJM of 1,000 MW

1. Example 1 – "Within NCTPC" – Duke to PEC-East – Increase interface by 500 MW



- Assumptions:
  - This RETP will require projects that increase the Duke to PEC-East interface capability by 500 MW for 10 years.
    - Transmission Customer 1 subscribes to 200 MW.
    - Transmission Customer 2 subscribes to 300 MW.
  - Total up-front funding requirement of $1 billion
    - Duke investment of $250 million
    - Progress investment of $750 million
  - Transmission Customer allocations for this funding:

    - TC 1 pays up-front payment of $400 million with a payment of 25% of these funds ($100 million) going to Duke and 75% of these funds going to Progress ($300 million)
    - TC 2 pays up-front payment of $600 million with a payment of 25% of these funds ($150 million) going to Duke and 75% of these funds going to Progress ($450 million)

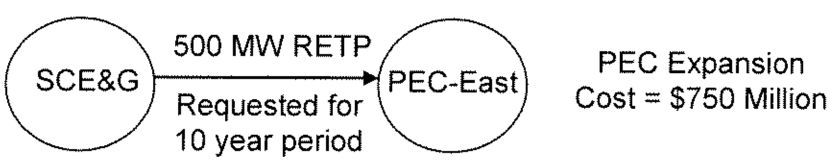
- RETP would be identified through the NCTPC TAG, approved for initial study by the OSC, and evaluated through the NCTPC study process. NCTPC process would determine the project cost (on both the Duke and Progress system), scope of the solution, and timing requirements for the implementation of the necessary upgrades as identified above in the "Identification and Initial Study of RETPs" section.
- Transmission cost considerations for this project –
  - Transmission Customers would be asked to provide the up-front funding of this transmission construction – total of $1 billion.
- NCTPC TAG stakeholder process would determine if there was sufficient interest to move the RETP from study mode to holding an Open Season. If the stakeholder group determines that an Open Season should be conducted the below steps would be taken.
- Open Season
    - Duke would hold an Open Season process for the 500 MW PTP Transmission Service reservation for the defined 10-year period from Duke into PEC-East.
    - Transmission Customers would have 60 days to determine if they want to participate in this Open Season.
    - For this example we will assume that there were adequate subscriptions as listed below:
        - Transmission Customer 1 – Willing to subscribe for 200 MW of PTP service
        - Transmission Customer 2 – Willing to subscribe for 300 MW of PTP service
        - Sufficient subscription, RETP moves forward.
    - Transmission Customer 1 is granted 200 MW of firm PTP Transmission Service from Duke to PEC-East for the 10 year period.

- Transmission Customer 2 is granted 300 MW of firm PTP Transmission Service from Duke to PEC-East for the 10 year period.
- Transmission Customers pay the up-front transmission construction costs – $250 million to Duke and $750 million to PEC.
- Transmission Customer pays Duke for the PTP Transmission Service each month at the Duke embedded cost transmission rate.
- Transmission Customers would receives credits back as follows:
    - Duke and Progress would both provide an annualized repayment of the initial funding of the transmission projects on their respective systems.
    - Duke will net their annualized repayment of the initial funding against the Transmission Customers charges for their PTP service that they take PTP service each month.

- Impact to Duke and Progress transmission rate base:
    - Duke and Progress will have the opportunity to include within their respective transmission rate bases the transmission that was constructed for the RETPs as the initial funding is repaid to the Transmission Customers over a 20 year period.

2. Example 2 – "Into NCTPC" – Into PEC-East – Increase PEC-East interface with SCE&G by 500 MW

Example assumes SCE&G/IRPP adopts RETP concept.

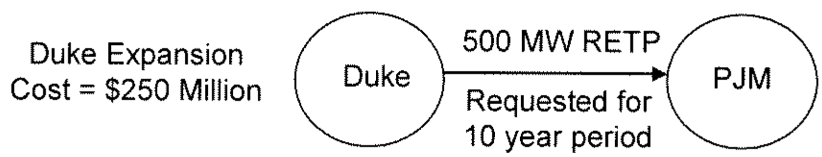


- This example builds off of Example 1. The differences in this example from Example 1 are as follows: Duke is not involved (i.e., Duke upgrades are not required and there is no Duke PTP service related to this example; and SCE&G is involved in the project (i.e., a Transmission Provider outside the NCTPC footprint). However, the Progress impacts are the same as were identified in Example 1.

- Since this example involves southeastern Transmission Providers outside of the NCTPC footprint (e.g. SCE&G), the IRPP would be used to evaluate this project and provide for an Open Season mechanism to determine if there was sufficient interest in moving forward with the RETP. Refer to Example 4 for an explanation of how those processes would work.

3. **Example 3 – "Out of NCTPC" – Duke to PJM of 500 MW**

   Example assumes PJM adopts RETP concept.

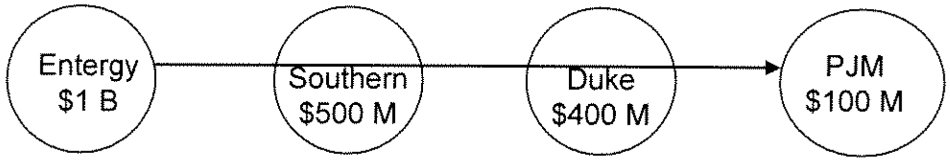


- This example builds off of Example 1. The differences in this example from Example 1 are as follows: Progress is not involved (i.e., there are no Progress upgrades required); and PJM is involved in the RETP (i.e., a northern Transmission Provider outside the NCTPC footprint). However the Duke impacts are the same as were identified in Example 1.
- Since this example involves Transmission Providers outside of the NCTPC footprint (i.e., PJM), Duke would work with PJM to evaluate this RETP and provide for an Open Season mechanism to determine if there was interest in moving forward with the project.

4. **Example 4 – "Through NCTPC" – Entergy to PJM of 1,000 MW**

   Example assumes PJM/IRPP adopts RETP concept.

   Entergy to PJM 1,000 MW RETP requested for a 20 year period.



- **Assumptions:**
  - Through the IRPP process an RETP was identified. This RETP was for the 1,000 MW coming from Entergy and being delivered to PJM for a 20 year period. This RETP would result in a 1,000 MW of PTP transmission service to be provided by the following Transmission Providers for 20 years: Entergy, Southern, and Duke. However, PJM would also need to participate in the study evaluation to determine if they had sufficient transmission interface to support this transaction.
  - Three Transmission Customers sign-up to participate in the RETP
    - Transmission Customer 1 subscribes at a level of 200 MW
    - Transmission Customer 2 subscribes to 300 MW
    - Transmission Customer 3 subscribes to 500 MW
  - Total up-front funding requirement of $2 billion
    - Entergy investment of $1billion
    - Southern investment of $500 million
    - Duke investment of $400 million
    - PJM investment of $100 million
    - The NCTPC only controls how Duke will handle the treatment of their initial funding of this economic project. The Transmission Customer would work with Entergy, Southern and PJM through this process concerning their initial funding requirements and potential rate impacts.
- RETP would be identified, approved, and evaluated through the IRPP. The IRPP would determine the RETP cost scope of the solution, and timing requirements for the implementation of the projects needed for the RETP as identified above in the "Identification and Initial Study of RETPs" section.
- Transmission cost considerations for Duke related to this project –
  - Transmission Customers would be asked to provide the up-front funding of the Duke transmission construction required by this RETP – $400 million.
- IRPP would determine if there was sufficient interest to move the RETP from study mode to holding an Open Season for the RETP. If the stakeholder group determines that an Open Season should be conducted the below steps would be taken.

- Open Season
  - A coordinated Open Season for this RETP would be held by Entergy, Southern and Duke for the 1,000 MW PTP Transmission Service reservation for the defined 20-year period from Entergy into PJM.
  - Transmission Customers would have 60 days to determine if they want to participate in this Open Season.
- For this example we will assume that there were adequate subscriptions as listed below:
  - Transmission Customer 1 subscribes at a level of 200 MW
  - Transmission Customer 2 subscribes to 300 MW
  - Transmission Customer 3 subscribes to 500 MW
- Transmission Customer 1 is granted 200 MW of firm PTP Transmission Service from Entergy to PJM for the 20 year period.
- Transmission Customer 2 is granted 300 MW of firm PTP Transmission Service from Entergy to PJM for the 20 year period.
- Transmission Customer 3 is granted 500 MW of firm PTP Transmission Service from Entergy to PJM for the 20 year period.
- The above three Transmission Customers would pay Duke for the PTP Transmission Service each month at the Duke embedded cost transmission rate.
- Transmission Customers would receives credits back as follows:
  - Duke would provide an annualized repayment of the initial funding of the transmission projects
  - Duke will net their annualized repayment of the initial funding against the Transmission Customers' charges for their PTP service that they take each month.
- Impact to the Duke transmission rate base:
  - Duke will have the opportunity to include within their transmission rate base the transmission that was constructed for the RETP as the initial funding is repaid to the Transmission Customers over a 20 year period.

<u>Inter-Regional Participation White Paper</u>

September 6, 2007

<u>Introduction:</u>

In an effort to more fully address the regional participation principle outlined in the Order 890 Attachment K Tariff requirements and the related guidance contained in the FERC Transmission Planning Process Staff White Paper (dated August 2, 2007), we propose to expand upon the existing processes for regional planning in the Southeast. This white paper is intended to outline an inter-regional process among various Southeastern interconnected transmission owners. The inter-regional process described herein would be incorporated into each Participating Transmission Provider's planning process and OATT Attachment K (for those transmission providers that have a regulatory requirement to file an Attachment K).

<u>Purpose:</u>

This inter-regional process would serve to complement the regional planning processes developed by the Participating Transmission Providers in the Southeast and to satisfy the regional participation principle established in FERC Order 890. For the purpose of this white paper, the term "Inter-Regional Participation Process" is defined as a new process to more fully address the inter-regional aspect of the regional participation principle of Order 890 for multiple transmission systems in the Southeast. The term "Regional Planning Processes" refers to the regional transmission planning processes a Transmission Provider has established within their particular region for Attachment K purposes.

<u>Current Inter-Regional Planning Process:</u>

Each Southeastern transmission provider currently develops a transmission plan to account for service to its native load and other firm transmission service commitments on its transmission system. This plan development is the responsibility of each transmission planner individually and does not directly involve the Regional Reliability Organization (e.g. SERC). Once developed, the Participating Transmission Providers collectively conduct an inter-regional reliability transmission assessment, which includes the sharing of the individual transmission system plans to provide information on the assumptions and data inputs and to assess whether the plans are simultaneously feasible.

<u>Participating Transmission Providers:</u>

Due to the additional regional planning coordination principals that have been announced in Order 890 and the associated Transmission Planning White Paper, the following transmission providers have agreed to provide additional transmission planning coordination, as further described in this document. The below identified transmission providers are referred to as the "Participating Transmission Providers":

Alabama Electric Cooperative	Progress Energy Carolinas
Duke Energy Carolinas	Santee Cooper
Dalton Utilities	South Carolina Electric & Gas
South Mississippi Electric Power Association	Entergy
Georgia Transmission Corporation	Southern Companies
Municipal Electric Authority of Georgia	Tennessee Valley Authority

Proposed Inter-Regional Participation Process:

The Inter-Regional Participation Process is outlined in the attached diagram. As shown in that diagram, this process will provide a means for conducting stakeholder requested Economic Planning Studies across multiple interconnected systems. In addition, this process will build on the current inter-regional, reliability planning processes required by existing multi-party reliability agreements to allow for additional participation by stakeholders.

The established Regional Planning Processes outlined in the Participating Transmission Providers' Attachment Ks will be utilized for collecting data, coordinating planning assumptions, and addressing stakeholder requested Economic Planning Studies internal to their respective regions. The data and assumptions developed at the regional level will then be consolidated and used in the development of models for use in the proposed Inter-Regional Participation Process. This will ensure consistency in the planning data and assumptions used in local, regional, and inter-regional planning processes.

These established Attachment K processes will also serve as a mechanism to collect requests for inter-regional Economic Planning Studies by each participant's stakeholders group. The Economic Planning Studies requested through each participant's Attachment K process that involve impacts on multiple systems will be consolidated and evaluated as part of the Inter-Regional Participation Process. The Inter-Regional Participation Process will also be described and included within each of the Participating Transmission Provider's Attachment K filings (as applicable).

The Participating Transmission Providers recognize the importance of coordination with neighboring (external) planning processes. Therefore, seams coordination will take place at the regional level where external regional planning processes adjoin the Inter-Regional Participation Process. External coordination is intended to include planning assumptions from neighboring processes and the coordination of transmission enhancements and stakeholder requested Economic Planning Studies to support the development of simultaneously feasible transmission plans both internal and external to the Inter-Regional Participation Process.

With regard to the development of the stakeholder requested inter-regional Economic Planning Studies, the Participating Transmission Providers will each provide staff (transmission planners) to serve on the study coordination team. The study coordination team will lead the development of study assumptions (and coordinate with stakeholders, as discussed further below), perform model development, and perform any other coordination efforts with stakeholders and impacted external planning processes. During the study process, the study coordination team will also be responsible for performing analysis, developing solution options, evaluating stakeholder suggested solution options, and developing a report(s) once the study(ies) is completed. Once the study(ies) is completed, the study coordination team will distribute the report(s) to all Participating Transmission Providers for review with stakeholders as a part their respective Regional Planning Process.

With regard to coordinating with stakeholders in the development of the inter-regional Economic Planning Study(ies), in each cycle of this Inter-Regional Participation Process, the Participating Transmission Providers will conduct the "1st Inter-Regional Stakeholder Meeting", as shown in the attached diagram. At this meeting, the study coordination team will coordinate with the stakeholders regarding the study assumptions underlying the identified stakeholder requested inter-regional Economic Planning Study(ies). Through this process, stakeholders will be provided an opportunity to comment and provide input regarding those assumptions. In addition, stakeholders will be provided an opportunity to request that additional inter-regional Economic Planning Studies be performed. Following that meeting, and once the study coordination team has an opportunity to perform its initial analyses of the inter-regional Economic Planning Study(ies), the Participating Transmission Providers will then conduct the "2nd Inter-Regional Stakeholder Meeting." At this meeting, the study coordination team will review the results of such initial analysis, and stakeholders will be provided an opportunity to comment and provide input regarding that initial analysis. The study coordination team will then perform its final analysis of the inter-regional study(ies) and draft the Economic Planning Study(ies) report(s), which will be presented to the stakeholders at the "3rd Inter-Regional Stakeholder Meeting." Stakeholders will be provided an opportunity to comment and provide input regarding the draft report(s). Subsequent to that meeting, the study coordination team will then finalize the report(s), which will be issued to the affected Participating Transmission Providers for review with stakeholders as a part their respective Regional Planning Process.

In addition to performing inter-regional Economic Planning Studies, the Inter-Regional Planning Process will also provide a means for the Participating Transmission Providers to review, at the Inter-Regional Participation Process stakeholder meetings, the regional data, assumptions, and assessments that are then being performed on an inter-regional basis.

<u>Inter-Regional Participation Process Cycle:</u>

The Inter-Regional Participation Process will be conducted over a two year cycle. Due to the expected scope of the requested studies and size of the geographical region encompassed, a two year evaluation cycle will ensure that sufficient coordination can occur with stakeholders and among the impacted Participating Transmission Providers. In addition, the two year cycle will provide sufficient time to ensure that the inter-regional study results are meaningful and meet the needs of the stakeholders.

Stakeholder Input in the Development of Inter-Regional Participation Process:

This white paper lays out a framework for inter-regional planning to address Order 890's regional participation principal and to otherwise provide a mechanism for the analysis of inter-regional Economic Planning Studies. The Participating Transmission Providers recognize the need to obtain stakeholder input as a part of finalizing the specifics of this process. To that end, the Participating Transmission Providers plan to engage stakeholders to receive their input concerning this framework in a variety of different forums including the following: through their Regional Planning Processes and through planned FERC Order 890 technical conferences in the fall of 2007. The goal being, that the Participating Transmission Providers' would finalize the specifics for the Inter-Regional Participation Process by the time they file their Attachment Ks in December 2007, with the goal of implementing this process beginning in 2008.

The further development of this process will include defining the process and procedures whereby the Economic Planning Studies can be requested by the stakeholders and evaluated through this inter-regional process. Details that will be further developed include the following: the number of studies that would be normally supported through the planning cycle; the process of determining how the requested studies would be prioritized; and the potential for performing additional studies if paid for by particular stakeholders. The stakeholders will have an opportunity to interact with the Participating Transmission Providers' in the development of these details.

Inter-Regional Participation Process Diagram: