Appendix D

Blacklined Version Comparing Joint OATT
to Florida Power Corporation OATT

~~Florida Power Corporation~~
~~FERC FPA Electric Tariff~~

JOINT

OPEN ACCESS TRANSMISSION TARIFF

OF

DUKE ENERGY CAROLINAS, LLC

FLORIDA POWER CORPORATION

AND

CAROLINA POWER & LIGHT COMPANY

~~Option Code A~~

~~Effective July 14, 2010~~

I. COMMON SERVICE PROVISIONS

~~1. DEFINITIONS~~

1 Definitions

1.1 Affiliate:

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Ancillary Services:

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 Annual Period:

The period of time coinciding with the calendar year beginning 12:00 a.m. on January 1 and ending 12:00 midnight on December 31, or a period of time that covers 12 consecutive months.

1.4 Annual Transmission Costs:

The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.5 Application:

A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.6 Commission:

The Federal Energy Regulatory Commission.

1.7 Completed Application:

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.8 Control Area:

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.9 CP&L:

Carolina Power & Light Company.

1.10 Curtailment:

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

~~**1.11 Daily Period:**~~

~~The period of time coinciding with the 24-hour calendar day beginning 12:00 a.m. and ending 12:00 midnight (military time 00:00 to 24:00).~~

~~1.12 Delivering Party:~~

1.11 DEC

Duke Energy Carolinas, LLC.

1.12 Delivering Party:

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.13 Designated Agent:

Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.14 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.15 Eligible Customer:

(i) Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power

Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.16 Facilities Study:

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.17 Firm Point-To-Point Transmission Service:

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.18 FPC:

Florida Power Corporation.

1.19 FRCC:

The Florida Reliability Coordinating Council, a regional reliability ~~council~~coordinator of NERC.

1.20 Generator Service:

Generator Regulation Service and Delivery Scheduling and Balancing Service, as provided in Section 3 and Schedule 3A.

1.21 Good Utility Practice:

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

1.22 Hourly Period:

A period of time consisting of 60 consecutive minutes beginning at the top of each hour.

1.23 Interruption:

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.24 Load Ratio Share:

~~Ratio~~In the CP&L Zone and in the FPC Zone, Load Ratio Share means the ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff ~~and calculated on a rolling twelve month basis~~.

In the DEC Zone, Load Ratio Share means the ratio of a Transmission Customer's Network Load to the Transmission Provider's Monthly Transmission System Peak computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff.

1.25 Load Shedding:

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III or IV of the Tariff.

1.26 Long-Term Firm Point-To-Point Transmission Service:

Firm Point-To-Point Transmission Service under Part II of the Tariff or Network Contract Demand Transmission Service under Part IV of the Tariff with a term of one year or more.

1.27 Monthly Period:

The period of time which coincides with the calendar month beginning on 12:00 a.m. on the first day of the month and ending 12:00 midnight on the last day of the month, or a period of time that covers 30 consecutive days.

1.28 Native Load Customers:

The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.29 NERC:

The North American Electric Reliability Council.

1.30 Network Contract Demand Customer:

An entity receiving transmission service pursuant to the terms of Part IV of the Tariff.

1.31 Network Contract Demand Transmission Service:

The transmission service provided under Part IV of the Tariff.

1.32 Network ~~Integration~~ Customer:

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.33 Network Integration Transmission Service:

The transmission service provided under Part III of the Tariff.

1.34 Network Load:

The load that a Network ~~Integration~~ Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network ~~Integration~~ Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network ~~Integration~~ Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Parts II or IV of the Tariff for any Point-To-Point Transmission Service or Network Contract Demand Transmission Service that may be necessary for such non-designated load.

1.35 Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service or Network Contract Demand Transmission Service under Parts III or IV, respectively, of the Tariff.

1.36 Network Operating Committee:

A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service or Network Contract Demand Transmission Service under Parts III or IV, respectively, of this Tariff.

1.37 Network Resource:

Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service or Network Contract Demand Transmission Service portions of the Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

1.38 Network Upgrades:

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.39 Non-Firm Point-To-Point Transmission Service:

Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.40 Non-Firm Sale:

An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

~~**1.41 Off Peak Days:**~~

~~Off-peak days are all hours during Saturday and Sunday of each week and, for service provided in the CP&L Zone, holidays. The following holidays are considered Off-Peak Days in the CP&L Zone: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.~~

~~**1.42 Off Peak Hours:**~~

~~Off-Peak Hours are all hours not considered On-Peak Hours. In the CP&L Zone, all hours for the following holidays are considered Off-Peak Hours: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.~~

~~**1.43 On-Peak Days:**~~

~~On-Peak Days are Monday through Friday of each week unless the day is considered a holiday as defined by Off-Peak Days.~~

~~**1.44 On-Peak Hours:**~~

~~On-Peak Hours are the hours from 7 a.m. through 11 p.m. (07:00 through 23:00 military time) during On-Peak Days.~~

~~1.45~~1.41 Open Access Same-Time Information System (OASIS):

The information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

~~1.46~~1.42 **Part I:**

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

~~1.47~~1.43 **Part II:**

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

~~1.48~~1.44 **Part III:**

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

~~1.49~~1.45 **Part IV:**

Tariff Sections 36 through 46 pertaining to Network Contract Demand Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

~~1.50~~1.46 **Parties:**

The Transmission Provider and the Transmission Customer receiving service under the Tariff.

~~1.51~~1.47 **Point(s) of Delivery:**

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreements for Long-Term Firm Point-To-Point

Transmission Service.

~~1.52~~1.48 **Point(s) of Receipt:**

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

~~1.53~~1.49 **Point-To-Point Transmission Service:**

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

~~1.54~~1.50 **Power Purchaser:**

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

~~1.55~~1.51 **Pre-Confirmed Application:**

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

~~1.56~~1.52 **Receiving Party:**

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

~~1.57~~1.53 **Regional Transmission Group (RTG):**

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

~~1.58~~1.54 **Reserved Capacity:**

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff or from Network Resources to Points of Delivery under Part IV of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

~~1.59~~1.55 **SERC:**

The Southeastern Electric Reliability ~~Council~~Corporation, a regional reliability ~~council~~ organization of NERC.

~~1.60~~1.56 **Service Agreement:**

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

~~1.61~~1.57 **Service Commencement Date:**

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3, Section 29.1 or Section 37.8 under the Tariff.

~~1.62~~1.58 **Short-Term Firm Point-~~to~~To-Point Transmission Service:**

Firm Point-To-Point Transmission Service under Part II of the Tariff or Network Contract Demand Transmission Service under Part IV of the Tariff with a term of less than one year.

~~1.63~~1.59 System Condition:

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-~~to~~To-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

~~1.64~~1.60 System Impact Study:

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service, Network Integration Transmission Service or Network Contract Demand Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

~~1.65~~1.61 Third-Party Sale:

Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service or a Point of Delivery under Network Contract Demand Service.

1.62 Time Periods:

The Daily Period is defined as the period of time coinciding with the 24-hour calendar day beginning 12:00 a.m. and ending 12:00 midnight (00:00 to 24:00 military time)

In the DEC Zone, the daily sliding period is the 24 hour period of time beginning at 11:00 p.m., 12:00 midnight, or 1:00 a.m. (23:00, 24:00 or 01:00 military time). On-peak days are defined as Monday through Friday of each week with the exception of the following holidays which are considered off-peak days: New

Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. All Saturdays and Sundays are considered off-peak days. In the CP&L Zone, Good Friday is also considered an off-peak day.

On-peak hours are the hours from 7 a.m. through 11 p.m. (07:00 through 23:00 military time) during on-peak days. All other hours are considered off-peak hours. Daily On-Peak Service is service provided during on-peak days. Daily Off-Peak Service is service provided during off-peak days. Hourly On-Peak Service is service provided during on-peak hours. Hourly Off-Peak Service is service provided during off-peak hours.

~~1.66~~1.63 Transmission Customer:

Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II or Part IV of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II, Part III and Part IV of this Tariff.

~~1.67~~1.64 Transmission Provider:

The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff~~.~~ as follows: (a) CP&L is the Transmission Provider in the CP&L Zone~~ and FPC~~; (b) FPC is the Transmission Provider in the FPC Zone; and (c) DEC is the Transmission Provider in the ~~FPC Zone.~~ DEC Zone.

~~1.68~~1.65 Transmission Provider's Monthly Transmission System Peak:

The maximum firm usage in a Zone of the Transmission Provider's Transmission System ~~in a calendar month.~~as determined under Section 34.3.

~~1.68~~1.66 Transmission Service:

Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

~~1.70~~1.67 Transmission System:

The facilities owned, controlled or operated by the Transmission Provider in a Zone that are used to provide transmission service under Part II, Part III and Part IV of the Tariff.

~~1.71~~1.68 Weekly Period:

~~The~~Weekly Period is the period of seven consecutive days coinciding with the calendar week beginning 12:00 a.m. Monday morning and ending 12:00 midnight on Sunday, or a period of time that covers seven consecutive days.

~~1.72~~1.69 Zone:

The Transmission System of DEC, the Transmission System of CP&L, or the Transmission System of FPC, as applicable.

~~2. INITIAL ALLOCATION AND RENEWAL PROCEDURES~~
2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transfer Capability:

For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority For Existing Firm Service Customers:

Existing firm service customers (wholesale requirements and transmission-only, with a contract term of five years or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service, the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service; provided that, the firm service customer shall have a right of first refusal at the end of such service only if the new contract is for five years or more. The existing firm service customer must provide notice to the Transmission Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of its transmission service agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. Service agreements subject to a right of first refusal entered into prior to October 15, 2008 for CP&L, April 1, 2009 for DEC, and July 25, 2008 for FPC or associated with a transmission service request received prior to July 13, 2007, unless terminated, will become subject to the five year/one year requirement on the first rollover date after October 15, 2008 for CP&L, April 1, 2009 for DEC, and July 25, 2008 for FPC; provided that, the one-year notice requirement shall apply to such service agreements with five years or more left in their terms as of October 15, 2008 for CP&L, April 1, 2009 for DEC, and July 25, 2008 for FPC.

~~3. ANCILLARY SERVICES AND GENERATOR SERVICES~~

3 Ancillary Services and Generator Services

Ancillary Services and Generator Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Spinning, and (iv) Operating Reserve - Supplemental. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Provider is required to provide (or offer to arrange with the local

Control Area Operator as discussed below), to the extent it is physically feasible to do so from its resources or from resources available to it, Generator Imbalance Service when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer using Transmission Service to deliver energy from a generator located within the Transmission Provider's Control Area is required to acquire Generator Imbalance Service, whether from the Transmission Provider, from a third party, or by self-supply.

For Transmission Service provided in the FPC Zone, the Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Generator Services: (i) Generator Regulation Service to the Transmission Customer serving load outside the Transmission Provider's Control Area from generation located inside the Transmission Provider's Control Area; and (ii) Delivery Scheduling and Balancing Service to the Transmission Customer that takes energy from generation located inside the Transmission Provider's Control Area.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services or Generator Services unless it demonstrates that it has acquired the Ancillary Services or Generator Services from another source. The Transmission Customer must list in its Application which Ancillary Services and Generator Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The

Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services and Generator Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services and Generator Services by acting as the Transmission Customer's agent to secure these Ancillary Services and Generator Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services and Generator Services directly from the Control Area operator, or (iii) secure the Ancillary Services and Generator Services (discussed in Schedules 3, 3A, 4, 5, ~~6,~~6 and ~~9~~13) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services or Generator Services by the Transmission Customer.

The specific Ancillary Services and Generator Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services and Generator Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service or Generator Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.7 below list the seven Ancillary Services and Generator Services.

3.1 Scheduling, System Control ~~A~~and Dispatch Service:

The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply ~~A~~and Voltage Control from Generation or Other Sources Service:

The rates and/or methodology are described in Schedule 2.

3.3 Regulation ~~A~~and Frequency Response Service:

Where applicable the rates and/or methodology are described in Schedule 3.

3.3~~a~~A Generator Regulation Service:

Where applicable the rates and/or methodology are described in Schedule 3A.

3.4 Energy Imbalance Service:

Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve - Spinning Reserve Service:

Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve - Supplemental Reserve Service:

Where applicable the rates and/or methodology are described in Schedule 6.

3.7 Generator Imbalance Service:

Where applicable the rates and/or methodology are described in Schedule ~~9.~~13.

3.8 Credits for Energy and Generation Imbalance Penalty Revenues:

Where applicable the rates and/or methodology are described in Schedules 4 and 13.

~~**4. OPEN ACCESS SAME-TIME INFORMATION SYSTEM (OASIS)**~~

4 Open Access Same-Time Information System (OASIS)

4.1 Terms and Conditions

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 C.F.R. § 7 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities) and 18 C.F.R. § 38 of the Commission's regulations (Business Practice Standards and Communication Protocols for Public Utilities). In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19, 32, and 40.

The Transmission Provider shall post on OASIS and its public website an electronic link to all rules, standards and practices that (i) relate to the terms and conditions of transmission service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff. The Transmission Provider shall post on OASIS and on its public website an electronic link to the NAESB website where any rules, standards and practices that are protected by copyright may be obtained. The Transmission Provider shall also post on OASIS and its public website an electronic link to a statement of the process by which the Transmission Provider shall add, delete or otherwise modify the rules, standards and practices that are not included in this ~~t~~Tariff. Such process shall set forth the means by which the Transmission Provider shall provide reasonable advance notice to Transmission Customers and Eligible Customers of any such additions, deletions or modifications, the associated effective date, and any additional implementation procedures that the Transmission Provider deems appropriate.

~~4.1~~4.2 NAESB WEQ Business Practice Standards

The following business practice and electronic communication standards promulgated by the North American Energy Standards Board (NAESB) Wholesale Electric Quadrant (WEQ) are incorporated herein by reference:

- Open Access Same-Time Information Systems (OASIS), Version 1.5 (WEQ-001, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009), with the exception of Standards 001-0.1, 001-0.9 through 001-0.13, 001-1.0, 001-9.7, 001-14.1.3, and 001-15.1.2;

- Open Access Same-Time Information Systems (OASIS) Standards & Communications Protocols, Version 1.5 (WEQ-002, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

- Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.5 (WEQ-003, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

- Coordinate Interchange (WEQ-004, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

- Area Control Error (ACE) Equation Special Cases (WEQ-005, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

- Manual Time Error Correction (WEQ-006, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007);

- Inadvertent Interchange Payback (WEQ-007, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

- Transmission Loading Relief - Eastern Interconnection (WEQ-008, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

- Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

- Public Key Infrastructure (PKI) (WEQ-012, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009); and

- Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.5 (WEQ-013, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009).

~~5. LOCAL FURNISHING BONDS~~

5 Local Furnishing Bonds

5.1 Transmission Providers That Own Facilities Financed ~~By~~by Local Furnishing Bonds:

This provision is applicable only to Transmission Providers that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local furnishing bonds"). Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide transmission service to any Eligible Customer pursuant to this Tariff if the provision of such transmission service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Provider's facilities that would be used in providing such transmission service.

5.2 Alternative Procedures ~~F~~for Requesting Transmission Service:

(i) If the Transmission Provider determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such transmission service, it shall advise the Eligible Customer within thirty (30) days of receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under

Section 211 of the Federal Power Act, the Transmission Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Transmission Provider's waiver of its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Transmission Provider shall be required to provide the requested transmission service in accordance with the terms and conditions of this Tariff.

~~**6. RECIPROCITY**~~

6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate Affiliates. A Transmission Customer that is a member of, or takes transmission service from, a power pool, Regional Transmission Group, Regional Transmission Organization (RTO), Independent System Operator (ISO) or other transmission organization approved by the Commission for the operation of transmission facilities also agrees to provide comparable transmission service to the transmission-owning members of such power pool and Regional Transmission Group, RTO, ISO or other transmission organization on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate Affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the Tariff, but also to all parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer~~s~~. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

~~7. BILLING AND PAYMENT~~
7 Billing and Payment

7.1 Billing Procedure:

Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission

Provider.

7.2 Interest ~~On~~on Unpaid Balances:

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Transmission Provider.

7.3 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the

Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

~~8. ACCOUNTING FOR THE TRANSMISSION PROVIDER'S USE OF THE TARIFF~~
8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues:

Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II or Part IV of the Tariff.

8.2 Study Costs ~~A~~and Revenues:

Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

~~9. REGULATORY FILINGS~~
9 Regulatory Filings

9.1 Federal Power Act Rights Retained~~:~~

~~Nothing~~Except as provided in Schedule 10-B, Exhibit A, Section 3(h), (a) nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service

Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder~~. Nothing~~, and (b) nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

9.2 Annual Informational Filings:

The Transmission Provider shall make annual filings with the Commission providing a summary of penalty revenue credits that were provided in accordance with the following: Energy and Generator Imbalance (reference Schedule 4, Sections ~~4.4~~4.2.2 and 4.3 and Schedule ~~9~~13, Sections ~~9.4~~13.1 and 13.2); late study penalties as described in Section 19.10; and unreserved use penalties as described in Sections A.7.~~7~~6 and B.7.6 of Schedule 7 and Sections A.8.7 and B.8.7 of Schedule 8, and Section 7.G of the DEC OASIS Business Practices (available at http://www.oatioasis.com/DUK/DUKdocs/Practices.pdf).

The annual filing will provide a summary of penalty revenue credits in each of the above areas by transmission customer, total penalty revenues collected from Affiliates, total penalty revenues collected from non-Affiliates, a description of the costs incurred as a result of the offending behavior, and a summary of the portion of the unreserved penalty revenue retained by the Transmission Provider. The annual compliance reports will be submitted on or before the Transmission Provider's deadline for submitting FERC Form-1, as established by the Commission's Office of Enforcement each year.

~~10. FORCE MAJEURE AND INDEMNIFICATION~~

10 Force Majeure and Indemnification

10.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

~~**11. CREDITWORTHINESS**~~

11 Creditworthiness

The Transmission Provider will specify its Creditworthiness procedures in Attachment ~~L.~~O.

~~12. DISPUTE RESOLUTION PROCEDURES~~

12 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures:

Any dispute between a Transmission Customer and the Transmission Provider involving transmission service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days, ~~[~~or such other period as the Parties may agree upon~~]~~, by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures:

Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

12.3 Arbitration Decisions:

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs:

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) one half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Rights Under The Federal Power Act:

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

II. POINT-TO-POINT TRANSMISSION SERVICE

~~*PREAMBLE*~~
Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

~~13. NATURE OF FIRM POINT-TO-POINT TRANSMISSION SERVICE~~
13 Nature of Firm Point-To-Point Transmission Service

13.1 Term:

The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority:

(i) Long-Term Firm Point-To-Point Transmission Service and Long-Term Network Contract Demand Transmission Service shall be available on a first-come, first-served basis i.e., in the chronological sequence in which each Transmission Customer has requested service.

In the DEC Zone, all Long-Term Firm Point-To-Point Transmission Service requests ("Long-Term Firm Requests") made within the first five minutes after the transmission reservation period set forth in the Transmission Provider's business practices opens for the service requested will be considered to have been submitted simultaneously. If the transmission reservation period for Network Resource designations is the same as the transmission reservation period for Long-Term Firm Requests, such Network Resource designations requests made within the first five minutes after the transmission reservation period opens also will be considered to have been submitted simultaneously with the Long-Term Firm Requests. If sufficient transfer capability is not available to meet all Long-Term Firm Requests and Network Resource designation requests that are considered to have been submitted simultaneously, available transfer capability first will be allocated based on pre-confirmation status (Pre-Confirmed or not confirmed). If insufficient transfer capability is available to accommodate all Pre-Confirmed Applications, then Pre-Confirmed Applications will be allocated a portion of the available transfer capability on a pro-rata basis. If sufficient transfer capability is available to accommodate all Pre-Confirmed Applications but not enough to accommodate all other requests, then the Pre-Confirmed Applications will be accepted and all other requests will be allocated a portion of the available transfer capability on a pro-rata basis.

(ii) Reservations for Short-Term Firm Point-To-Point Transmission Service and Short-Term Network Contract Demand Transmission Service will be conditional based upon the length of the requested transaction or reservation. However, Pre-Confirmed Applications for Short-Term Point-~~to~~To-Point Transmission Service will receive priority over earlier-submitted requests that are not Pre-Confirmed and that have equal or shorter duration. Among requests or reservations with the same duration and, as relevant, pre-confirmation status (pre-confirmed, confirmed, or not confirmed), priority will be given to an Eligible Customer's request or reservation that offers the highest price, followed by the date and time of the request or reservation.

(iii) If the Transmission System becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service.

Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, an Eligible Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service or Short-Term Network Contract Demand Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in sections 13.8 or 36.9) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. When a longer duration request preempts multiple shorter duration reservations, the shorter duration reservations shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which ~~the~~ multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff.

(iv) Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers, Network ~~Integration~~ Customers and Long-Term Network Contract Demand Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

In the DEC Zone, Short-Term Firm requests made within the first five minutes after the transmission reservation period set forth in the Transmission Provider's business practices opens for the service requested will be grouped by price and then duration time; the following procedure will be used to allocate capacity if insufficient transfer capability is available to accommodate all requests, starting with the group of requests with the longest duration:

a) If insufficient transfer capability is available to accommodate all pre-confirmed requests, then all pre-confirmed requests will be counteroffered on a pro-rata basis and all requests that are not pre-confirmed will be refused.

b) If sufficient transfer capability is available to accommodate all pre-confirmed requests, but not enough to accommodate all other requests, then the pre-confirmed requests will be accepted and all other requests will be counteroffered on a pro-rata basis.

c) If sufficient transfer capability is available to accommodate all requests of a given duration, all requests will be accepted and the next-longest duration group will be evaluated in a similar fashion.

13.3 Use ~~Of~~of Firm Transmission Service ~~By~~by ~~T~~the Transmission Provider:

The Transmission Provider will be subject to the rates, terms and conditions of Part II or Part IV of the Tariff when making Third-Party Sales under (i) agreements executed on or after July 9, 1996 or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service or Network Contract Demand Service to make Third-Party Sales.

13.4 Service Agreements:

The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement. The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in Section 15.4, the Transmission Provider shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions. Concurrent with such notice, the Transmission Provider shall provide the Transmission Customer with the reassessment study and a narrative description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur.

13.5 Transmission Customer Obligations ~~F~~for Facility Additions ~~Or~~or Redispatch Costs:

In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network ~~Integration~~ Customers, Network Contract Demand Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint by redispatching the Transmission Provider's resources, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 and agrees to either (i) compensate the Transmission Provider for any necessary transmission facility additions or (ii) accept the service subject to a biennial reassessment by the Transmission Provider of redispatch requirements as described in Section 15.4. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment ~~Of~~of Firm Transmission Service:

In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system and the systems directly and indirectly interconnected with Transmission Provider's Transmission System, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. The Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment ~~N~~L. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network ~~Integration~~ Customers, Network Contract Demand Customers, and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. Long-Term Firm Point-~~to~~To-Point Service subject to conditions described in Section 15.4 shall be curtailed with secondary service in cases where the conditions apply, but otherwise will be curtailed on a pro rata basis with other Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission

Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

In the CP&L Zone and the FPC Zone, in the event a Transmission Customer fails to implement a Curtailment within ten minutes as required by the Transmission Provider, the Transmission Customer shall pay, in addition to any other charges for service, a charge equal to two times the amount of transmission service which the Transmission Customer fails to curtail multiplied by the maximum charge for Firm Point-To-Point Transmission Service for the lesser of the transaction term or one month.

13.7 Classification ~~Of~~of Firm Transmission Service:

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22.

(d) In the event that ~~a~~the Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any

Point of Receipt or Point of Delivery, or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved, the Transmission Customer shall pay the rate for unauthorized use as specified in Schedule 7.

13.8 Scheduling ~~Of~~of Firm Point-To-Point Transmission Service:

Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10:00 a.m. of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. In the CP&L Zone and in the DEC Zone scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. In the DEC Zone, scheduling changes submitted less than twenty (20) minutes before the start of the next clock hour will be accommodated, if practicable. In the FPC Zone, scheduling changes will be permitted up to ten (10) minutes before the start of the next clock hour provided that the Delivering Party and the Receiving Party also agree to the schedule modification and that the transaction can be reasonably accommodated on the Transmission System. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

~~14. NATURE OF NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE~~

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term:

Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority:

Non-Firm Point-To-Point Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network ~~Integration~~ Customers, Network Contract Demand Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned first to requests or reservations with a longer duration of service, and second to Pre-Confirmed Applications. In the event the Transmission System is constrained, competing requests of the same Pre-Confirmation status and equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term request before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non- Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network ~~Integration~~ Customers or Network Contract Demand Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use ~~Of~~of Non-Firm Point-To-Point Transmission Service ~~By~~by ~~T~~the Transmission Provider:

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after July 9, 1996 or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section

8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements:

The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification ~~Of~~of Non-Firm Point-To-Point Transmission Service:

Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. In the event that ~~a~~the Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm ~~capacity reservation~~Reserved Capacity at any Point of Receipt and/or Point of Delivery, the Transmission Customer shall pay the rate for unauthorized use as specified in Schedule 8. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling ~~Of~~of Non-Firm Point-To-Point Transmission Service:

Schedules for Non-Firm Point-To-Point Transmission Service in the CP&L Zone or in the DEC Zone must be submitted to the Transmission Provider no later than 2:00 p.m. of the day prior to commencement of such service. Schedules for Non-Firm Point-To-Point Transmission Service in the FPC Zone must be submitted to the Transmission Provider no later than fifteen (15) minutes before the scheduled start of hourly transactions or one hour prior to the scheduled start of longer-term transactions. Schedules submitted after such times will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. In the CP&L Zone and in the DEC Zone scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. In the ~~FPC~~DEC Zone, scheduling changes ~~will be permitted up to ten (10~~submitted less than twenty (20) minutes before the start of the next clock hour will be accommodated, if practicable. In the FPC Zone scheduling changes will be permitted up to ten (10) minutes before the start of the next clock hour provided that the Delivering Party and the Receiving Party also agree to the schedule modification and that the transaction can be reasonably accommodated on the Transmission System. The Transmission Provider will furnish to the Delivering

Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment ~~Or~~or Interruption ~~Of~~of Service:

The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System or the systems directly or indirectly interconnected with Transmission Provider's Transmission System. The Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment ~~N~~L. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, (4) transmission service for Network ~~Integration~~ Customers and Network Contract Demand Customers from non-designated resources, or (5) transmission service for Firm Point-~~to~~To-Point Transmission Service during conditional curtailment periods as described in Section 15.4. The Transmission

Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network ~~Integration~~ Customers and Network Contract Demand Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice. In the CP&L Zone and the FPC Zone, in the event a Transmission Customer fails to implement a Curtailment within ten minutes or Interruption within twenty minutes as required by the Transmission Provider, the Transmission Customer shall pay, in addition to any other charges for service, a charge equal to two times the amount of transmission service which the

Transmission Customer fails to curtail or interrupt multiplied by the maximum charge for Firm Point-To-Point Transmission Service for the lesser of the transaction term or one month.

~~15. SERVICE AVAILABILITY~~
15 Service Availability

15.1 General Conditions:

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination ~~Of~~of Available Transfer Capability:

A description of the Transmission Provider's specific methodology for assessing available transfer capability posted on the relevant Transmission Provider's OASIS (Section 4) is contained in Attachment C-1 (CP&L Zone), Attachment C-2 (FPC Zone), and Attachment C-3 (DEC Zone), as applicable, of the Tariff. In the event sufficient transfer capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service ~~In~~in ~~T~~the Absence ~~Of An~~of an Executed Service Agreement:

If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation ~~To~~to Provide Transmission Service ~~T~~that Requires Expansion ~~Or~~or Modification ~~Of~~of ~~T~~the Transmission System, Redispatach ~~Or~~ or Conditional Curtailment:

(a) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, consistent with its planning obligations in Attachment ~~K~~N-1 (CP&L Zone and DEC Zone) or Attachment N-2 (FPC Zone), as applicable, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice and its planning obligations in Attachment ~~K~~N-1 or Attachment N-2, as applicable, in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

(b) If the Transmission Provider determines that it cannot accommodate a Completed Application for Long-Term Firm Point-To-Point Transmission

Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to provide redispatch from its own resources until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide the redispatch, or (iii) the Transmission Customer terminates the service because of redispatch changes resulting from the reassessment. A Transmission Provider shall not unreasonably deny self-provided redispatch or redispatch arranged by the Transmission Customer from a third party resource.

(c) If the Transmission Provider determines that it cannot accommodate a Completed Application for Long-Term Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will offer the Firm Transmission Service with the condition that the Transmission Provider may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s). If the Transmission Customer accepts the service, the Transmission Provider will use due diligence to provide the service until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide such service, or (iii) the Transmission Customer terminates the service because the reassessment increased the number of hours per year of conditional curtailment or changed the System Conditions.

15.5 Deferral ~~Of~~of Service:

The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules:

Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

15.7 Real Power Losses:

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider.

The applicable Real Power Loss factor in the CP&L Zone is 2.15%~~ and the~~.

The applicable Real Power Loss factors in the FPC Zone are 2.05% for delivery at transmission voltages and 3.05% for delivery at distribution voltages. Procedures for annual changes to the Real Power Loss factors in the FPC Zone are set out in Attachment ~~M.~~Q.

The applicable Real Power loss factors in the DEC Zone are as follows: The loss factor used to determine the amount of losses associated with the use of facilities at or above 44 kV shall be three (3) percent. In the DEC Zone, the

Transmission Provider and Transmission Customer may agree to have the Transmission Provider supply the capacity and/or energy necessary to compensate for losses in accordance with Schedule 9.

~~**16. TRANSMISSION CUSTOMER RESPONSIBILITIES**~~

16 Transmission Customer Responsibilities

16.1 Conditions Required ~~Of~~of Transmission Customers:

Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

a. The Transmission Customer has pending a Completed Application for service;

b. The Transmission Customer meets the creditworthiness criteria set forth in Attachment ~~L;~~O;

c. The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

d. The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation;

e. The Transmission Customer provides the information required by the Transmission Provider's planning process established in Attachment ~~K~~N-1 or Attachment N-2, as applicable; and

f. The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility ~~F~~for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

~~17. PROCEDURES FOR ARRANGING FIRM POINT-TO-POINT TRANSMISSION SERVICE~~

17 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application: A request for Firm Point-To-Point Transmission Service for periods of one year or longer must ~~contain a written Application to:~~ be made on the OASIS of the Transmission Provider of each affected Zone. ~~Carolina Power & Light Company, 3401 Hillsborough Street, Raleigh, North Carolina 27607, if the Point of Delivery is in the CP&L Zone; and to: Florida Power Corporation, 6565 38th Avenue North, St. Petersburg, Florida 33710, if the Point of Delivery is in the FPC Zone;~~ Such Application[s] must be submitted at least sixty (60) days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the OASIS for ~~the Zone in which the energy being transmitted is consumed, or if the energy is transmitted to an interface with another transmission provider, the OASIS for the Zone in which the Transmission Provider last provides transmission service; and if service is requested in two Zones, by also notifying the OASIS in the other Zone pursuant to an OASIS posting.~~ each affected Zone.

17.2 Completed Application:

A Completed Application shall provide all of the information included in 18 C.F.R. § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service;

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

(ix) A statement indicating that, if the Eligible Customer submits a Pre-Confirmed Application, the Eligible Customer will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service; and

(x) Any additional information required by the Transmission Provider's planning process established in Attachment ~~K.~~N-1 or Attachment N-2, as applicable.

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

17.3 Deposit:

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Transmission Provider's account. Notwithstanding the foregoing, the Transmission Provider shall on a non-discriminatory basis waive the requirement that a deposit accompany an Application for an Eligible Customer that has met the necessary conditions of ~~Sections 1.2 or 1.3 of~~ Attachment ~~L~~O of this Tariff.

17.4 Notice ~~Of~~of Deficient Application:

If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response ~~To A~~to a Completed Application:

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transfer capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1. Responses by the Transmission Provider must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

17.6 Execution ~~Of~~of Service Agreement:

Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an

Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 15.3, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions ~~F~~for Commencement ~~Of~~of Service:

The Transmission Customer can obtain, subject to availability, up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof within 15 days of notifying the Transmission Provider it intends to extend the commencement of service. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

~~18. PROCEDURES FOR ARRANGING NON FIRM POINT TO POINT TRANSMISSION SERVICE~~

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application:

Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. ~~Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application.~~

18.2 Completed Application:

A Completed Application shall provide all of the information included in 18 C.F.R. § S2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

(viii) A statement indicating that, if the Eligible Customer submits a Pre-Confirmed Application, the Eligible Customer will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

18.3 Reservation ~~Of~~of Non-Firm Point-To-Point Transmission Service:

Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) days before service is to commence, and requests for hourly service shall be submitted no earlier than noon the day before service is to commence. Requests for service in the CP&L Zone and requests for service in the DEC Zone received later than 2:00 p.m. prior to the day service is scheduled to commence ~~and requests~~will be accommodated if practicable. Requests for service in the FPC Zone received later than 15 minutes before the scheduled start of hourly service or twelve noon prior to the day longer term service is scheduled to commence will be accommodated if practicable.

18.4 Determination ~~Of~~of Available Transfer Capability:

Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service: (i) in the CP&L Zone and in the DEC Zone, thirty (30) minutes for hourly service, and in the FPC Zone, prior to the requested start of the transaction for hourly service~~,~~; (ii) in all Zones, thirty (30) minutes for daily service~~,~~; (iii) in all Zones, four (4) hours for weekly service~~,~~; and (iv) in all Zones, two (2) days for monthly service.

~~**19. ADDITIONAL STUDY PROCEDURES FOR FIRM POINT-TO-POINT TRANSMISSION SERVICE REQUESTS**~~

19 Additional Study Procedures For Firm Point-To-Point Transmission Service Requests

19.1 Notice ~~Of~~of Need ~~F~~for System Impact Study:

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. Once informed, the Eligible Customer shall timely notify the Transmission Provider if it elects to have the Transmission Provider study redispatch or conditional curtailment as part of the System Impact Study. If notification is provided prior to tender of the System Impact Study Agreement, the Eligible Customer can avoid the costs associated with the study of these options. The Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement ~~A~~and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 20.

19.3 System Impact Study Procedures:

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify (1) any system constraints~~,~~ identified with specificity by transmission element or flowgate, (2) redispatch options (when requested by an Eligible Customer) including an estimate of the cost of redispatch, (3) conditional curtailment options (when requested by an Eligible Customer) including the number of hours per year and the System Conditions during which conditional curtailment may occur, and (4) additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. For customers requesting the study of redispatch options, the System Impact Study shall (1) identify all resources located within the Transmission Provider's Control Area that can significantly contribute toward relieving the system constraint and (2) provide a measurement of each resource's impact on the system constraint. If the Transmission Provider possesses information indicating that any resource outside its Control Area could relieve the constraint, it shall identify each such resource in the System Impact Study. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures:

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications:

Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence ~~In~~in Completing New Facilities:

The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service:

If the Transmission Provider determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures ~~F~~for New Facilities:

In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

19.9 Penalties for Failure to Meet Study Deadlines:

Sections 19.3 and 19.4 require a Transmission Provider to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The Transmission Provider is required to file a notice with the Commission in the event that more than twenty (20) percent of non-Affiliates' System Impact Studies and Facilities Studies completed by the Transmission Provider in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of non-Affiliates' System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the Transmission Provider shall consider all System Impact Studies and Facilities Studies that it completes for non-Affiliates during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The Transmission Provider may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The Transmission Provider is subject to an operational penalty if it completes ten (10) percent or more of non-Affiliates' System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the Transmission Provider's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the Transmission Provider completes at least ninety (90) percent of all non-Affiliates'

System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the Transmission Provider takes to complete that study beyond the 60-day deadline.

19.10 Credits for Late Study Penalty Revenues:

The Transmission Provider will provide credits back to Transmission Customers for the penalties assessed under Section 19.9. These credits will be provided in accordance with the below provisions.

The operational penalties pursuant to Section 19.9(iii) and (iv) shall be credited based on the ratio of the quarterly transmission revenues collected from each Network Transmission Customer (excluding any Transmission Provider Affiliates) or Point-~~to~~To-Point Transmission Customer (excluding any Transmission Provider Affiliates) to the sum of the transmission revenues from all Transmission Customers (excluding any Transmission Provider Affiliates). The operational penalties will be refunded to the Transmission Customers based on the quarters the operational penalty applies.

The Transmission Provider will disburse accumulated operational penalty revenues, plus interest calculated in accord with 18 C.F.R. § 35.19a, within 60 days after the end of the quarter where a penalty was assessed.

~~20. PROCEDURES IF THE TRANSMISSION PROVIDER IS UNABLE TO COMPLETE NEW TRANSMISSION FACILITIES FOR FIRM POINT-TO-POINT TRANSMISSION SERVICE~~

20 Procedures if The Transmission Provider is Unable to Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

20.1 Delays ~~In~~in Construction ~~Of~~of New Facilities:

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives ~~To~~to ~~T~~the Original Facility Additions:

When the review process of Section 20.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

20.3 Refund Obligation ~~F~~for Unfinished Facility Additions:

If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

~~21. PROVISIONS RELATING TO TRANSMISSION CONSTRUCTION AND SERVICES ON THE SYSTEMS OF OTHER UTILITIES~~

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility ~~F~~for Third-Party System Additions:

The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination ~~Of~~of Third-Party System Additions:

In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

~~22. CHANGES IN SERVICE SPECIFICATIONS~~
22 Changes in Service Specifications

22.1 Modifications On ~~A~~a Non-Firm Basis:

The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modification On ~~A~~a Firm Basis:

Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

~~23. SALE OR ASSIGNMENT OF TRANSMISSION SERVICE~~
23 Sale or Assignment of Transmission Service

23.1 Procedures ~~F~~for Assignment ~~Or~~or Transfer ~~Of~~of Service:

(a) A Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee.

(b) The Assignee must execute a service agreement with the Transmission Provider governing reassignments of transmission service prior to the date on which the reassigned service commences. The Transmission Provider shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Service Agreement with the Transmission Provider or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the Transmission Provider or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the

Reseller. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations ~~On~~on Assignment ~~Or~~or Transfer ~~Of~~of Service:

If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Transmission Provider and the Reseller through an amendment to the Service Agreement.

23.3 Information ~~On~~on Assignment ~~Or~~or Transfer ~~Of~~of Service:

In accordance with Section 4, all sales or assignments of capacity must be conducted through or otherwise posted on the Transmission Provider's OASIS on or before the date the reassigned service commences and are subject to Section 23.1. Resellers may also use the Transmission Provider's OASIS to post transmission capacity available for resale.

~~24. METERING AND POWER FACTOR CORRECTION AT RECEIPT AND DELIVERY POINTS(S)~~

24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations:

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access ~~To~~to Metering Data:

The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor:

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

~~25. COMPENSATION FOR TRANSMISSION SERVICE~~
25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); Non-Firm Point-To-Point Transmission Service (Schedule 8); and Distribution Substation Service in the FPC Zone (Schedule 11). The Transmission Provider shall use Part II or Part IV-of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

~~26. STRANDED COST RECOVERY~~
26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

~~27. COMPENSATION FOR NEW FACILITIES AND REDISPATCH COSTS~~

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved by redispatching the Transmission Provider's resources to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

III. NETWORK INTEGRATION TRANSMISSION SERVICE

~~**PREAMBLE**~~
Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network ~~Integration~~ Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network ~~Integration~~ Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as -available basis without additional charge. Transmission Service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II or Part IV of the Tariff.

~~**28. NATURE OF NETWORK INTEGRATION TRANSMISSION SERVICE**~~
28 Nature of Network Integration Transmission Service

28.1 Scope ~~Of~~of Service:

Network Integration Transmission Service is a transmission service that allows Network ~~Integration~~ Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network ~~Integration~~ Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities:

The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment ~~K~~N-1 or Attachment N-2, as applicable, in order to provide the Network ~~Integration~~ Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network ~~Integration~~ Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network ~~Integration~~ Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice and Attachment ~~K~~N-1 or Attachment N-2, as applicable, endeavor to construct and place into service sufficient transfer capability to deliver the Network ~~Integration~~ Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 Network Integration Transmission Service:

The Transmission Provider will provide firm transmission service over its Transmission System to the Network ~~Integration~~ Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service:

The Network ~~Integration~~ Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff. In the DEC Zone, if the transmission reservation period for firm requests is the same as for secondary service requests, if after allocating transfer capability to firm requests as described in Sections 13.2 and 30.2 of this Tariff, there is some transfer capability but not sufficient transfer capability to meet all secondary service reservations that are considered to have been submitted simultaneously, the available transfer capability will be allocated pro rata based on the quantity of service (MW) requested.

28.5 Real Power Losses:

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network ~~Integration~~ Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider.

The applicable Real Power Loss factor in the CP&L Zone is 2.15%~~ and the~~. The applicable Real Power Loss factors in the FPC Zone are 2.05% for delivery at transmission voltages and 3.05% for delivery at distribution voltages.

Procedures for annual changes to the Real Power Loss factors in the FPC Zone are set out in Attachment ~~M~~Q.

The applicable Real Power Loss factor in the DEC Zone used to determine the amount of losses associated with the use of facilities at or above 44 kV shall be three (3) percent. In the DEC Zone, the Transmission Provider and Transmission Customer may agree to have the Transmission Provider supply the capacity and/or energy necessary to compensate for losses in accordance with Schedule 9.

28.6 Restrictions ~~On~~on Use ~~Of~~of Service:

The Network ~~Integration~~ Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network ~~Integration~~ Customer to third parties. All Network ~~Integration~~ Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff or Network Contract Demand Transmission Service under Part IV of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System. The Transmission Provider shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve a Network Load. Such use will be treated as an unreserved use of Point-To-Point Transmission Service and will be subject to the unreserved use penalties for such service set forth in Section 13.7.

~~29. INITIATING SERVICE~~

29 Initiating Service

29.1 Condition Precedent ~~F~~for Receiving Service:

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F-1 or Attachment F-2, as applicable, for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, (iv) the Eligible Customer meets the Creditworthiness criteria set forth in Attachment ~~L~~O, and (v) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G (in the DEC Zone, the Network Operating Agreement is Attachment E to the Form of Service Agreement for Network Integration Transmission Service (available at Attachment F-2 to the Tariff)), or requests in writing that Transmission Provider file a proposed unexecuted Network Operating Agreement.

29.2 Application Procedures:

An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence; provided that the Transmission Provider shall on a non-discriminatory basis waive the requirement that a deposit accompany an Application for an Eligible Customer that has met the necessary conditions of

~~Sections 1.2 or 1.3 of~~ Attachment ~~L~~O of this Tariff. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. A Completed Application shall provide all of the information included in 18 C.F.R. § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10- year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
  - Any periods of restricted operations throughout the year
  - Maintenance schedules

- Minimum loading level of unit
- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons

- Approximate variable generating cost ($/MWH) for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource;

For each off-system Network Resource, such description shall include:

- Identification of the Network Resource as an off-system resource
- Amount of power to which the customer has rights
- Identification of the control area from which the power will originate
- Delivery point(s) to the Transmission Provider's Transmission System
- Transmission arrangements on the external transmission system(s)
- Operating restrictions, if any
    - Any periods of restricted operations throughout the year
    - Maintenance schedules
    - Minimum loading level of unit
    - Normal operating level of unit
    - Any must-run unit designations required for system reliability or contract reasons
- Approximate variable generating cost ($/MWH) for redispatch computations;

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- 10- year projection of system expansions or upgrades
- Transmission System maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other

Control Areas;

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year;

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 29.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program; and

(ix) Any additional information required of the Transmission Customer as specified in the Transmission Provider's planning process established in Attachment ~~K~~N-1 or Attachment N-2, as applicable.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements ~~To Be~~to be Completed Prior ~~To~~to Commencement ~~Of~~of Service:

Network Integration Transmission Service shall not commence until the Transmission Provider and the Network ~~Integration~~ Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network ~~Integration~~ Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities:

The provision of Network Integration Transmission Service shall be conditioned upon the Network ~~Integration~~ Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network ~~Integration~~ Customer. The Network ~~Integration~~ Customer shall be solely responsible for constructing or installing all facilities on the Network ~~Integration~~ Customer's side of each such delivery point or interconnection.

29.5 Filing ~~Of~~of Service Agreement:

The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

~~30. NETWORK RESOURCES~~
30 Network Resources

30.1 Designation ~~Of~~of Network Resources:

Network Resources shall include all generation owned, purchased or leased by the Network ~~Integration~~ Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network ~~Integration~~ Customer's Network Load or a Network Contract Demand Customer's Network Contract Demand on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. Any owned or purchased resources that were serving the Network ~~Integration~~ Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network ~~Integration~~ Customer terminates the designation of such resources.

30.2 Designation ~~Of~~of New Network Resources:

The Network ~~Integration~~ Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. The Network Customer's request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff. One day is the minimum term for a Network Resource designation.

In the DEC Zone, all Applications to designate Network Resources made within the first five minutes after the transmission reservation period set forth in the Transmission Provider's business practices opens for the service requested will be considered to have been submitted simultaneously. If the transmission reservation period for Network Resource designations is the same as the transmission reservation period for Long-Term Firm Requests, such Network Resource designations requests made within the first five minutes after the transmission reservation period opens also will be considered to have been submitted simultaneously with the Long-Term Firm Requests. If sufficient transfer capability is not available to meet all Long-Term Firm Requests and Network Resource designation requests that are considered to have been submitted simultaneously, available transfer capability first will be allocated based on pre-confirmation status (Pre-Confirmed or not confirmed). If insufficient transfer capability is available to accommodate all Pre-Confirmed Applications, then Pre-Confirmed Applications will be allocated a portion of the available transfer capability on a pro-rata basis.

In the DEC Zone, if sufficient transfer capability is available to accommodate all Pre-Confirmed Applications but not enough to accommodate all other requests, then the Pre-Confirmed Applications will be accepted and all other requests will be allocated a portion of the available transfer capability on a pro-rata basis.

30.3 Termination ~~Of~~of Network Resources:

The Network ~~Integration~~ Customer may terminate the designation of all or part of a generating resource as a Network Resource by pr+oviding notification to the Transmission Provider through OASIS ~~as soon as reasonably practicable, but not later than the firm scheduling deadline for the period of termination.~~no later than 10:00 a.m. of the day prior to the commencement of the termination. Requests to terminate Network Resources submitted after 10:00 a.m. of the day prior to the commencement of the termination will be accommodated, if practicable. Any request for termination of Network Resource status must be submitted on OASIS, and should indicate whether the request is for indefinite or temporary termination. A request for indefinite termination of Network Resource status must indicate the date and time that the termination is to be effective, and the identification and capacity of the resource(s) or portions thereof to be indefinitely terminated. A request for temporary termination of Network Resource status must include the following:

(i) Effective date and time of temporary termination;

(ii) Effective date and time of redesignation, following period of temporary termination;

(iii) Identification and capacity of resource(s) or portions thereof to be temporarily terminated;

(iv) Resource description and attestation for redesignating the network resource following the temporary termination, in accordance with Section 30.2; and

(v) Identification of any related transmission service requests to be evaluated concomitantly with the request for temporary termination, such that the requests for undesignation and the request for these related transmission service requests must be approved or denied as a single request. The evaluation of these related transmission service requests must take into account the termination of the network resources identified in (iii) above, as well as all competing transmission service requests of higher priority.

As part of a temporary termination, a Network Customer may only redesignate the same resource that was originally designated, or a portion thereof. Requests to redesignate a different resource and/or a resource with increased capacity will be deemed deficient and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.4 Operation ~~Of~~of Network Resources:

The Network ~~Integration~~ Customer shall not operate its designated Network Resources located in the Network ~~Integration~~ Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load and its Network Contract Demand under Part IV, plus Non-Firm Sales delivered pursuant to Part II of the Tariff, plus losses, plus power sales under a reserve sharing program, plus sales that permit curtailment without penalty to serve its designated Network Load. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the Transmission Provider's Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Section 29, unless the Network Customer supports such delivery within the Transmission Provider's Transmission System by either obtaining Point-~~to~~To-Point Transmission Service or utilizing secondary service pursuant to Section 28.4. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-~~to~~To-Point Transmission Service. In the DEC Zone, such delivery will be treated as an unreserved use of Point-To-Point Transmission Service and subject to the unreserved use penalties for such service set forth in Section 13.7.

30.5 Network Customer Redispatch Obligation:

As a condition to receiving Network Integration Transmission Service, the Network ~~Integration~~ Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network ~~Integration~~ Customers, Network

Contract Demand Customers and the Transmission Provider.

30.6 Transmission Arrangements ~~F~~for Network Resources Not Physically Interconnected With The Transmission Provider:

The Network ~~Integration~~ Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network ~~Integration~~ Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation ~~On~~in Designation ~~Of~~of Network Resources:

The Network ~~Integration~~ Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network ~~Integration~~ Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use ~~Of~~of Interface Capacity ~~By~~by ~~T~~the Network Customer:

There is no limitation upon a Network ~~Integration~~ Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network ~~Integration~~ Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network ~~Integration~~ Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network ~~Integration~~ Customer's Load.

30.9 Network ~~Integration~~ Customer Owned Transmission Facilities:

The Network~~ Integration~~ Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network ~~Integration~~ Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. For facilities added by the Network ~~Integration~~ Customer subsequent to July 13, 2007, the Network ~~Integration~~ Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission Provider's facilities; provided however, the Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's annual transmission revenue requirement as specified in Attachment H. Calculation of any credit under this subsection shall be addressed in either the Network ~~Integration~~ Customer's Service Agreement or any other agreement between the Parties.

~~31. DESIGNATION OF NETWORK LOAD~~
31 Designation of Network Load

31.1 Network Load:

The Network~~ Integration~~ Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With ~~T~~the Transmission Provider:

The Network ~~Integration~~ Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network ~~Integration~~ Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network ~~Integration~~ Customer in accordance with Commission policies.

31.3 Network Load Not Physically Interconnected With ~~T~~the Transmission Provider:

This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network ~~Integration~~ Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network ~~Integration~~ Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff or Network Contract Demand Transmission Service under Part IV of the Tariff. To the extent that the Network ~~Integration~~ Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points:

To the extent the Network ~~Integration~~ Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network ~~Integration~~ Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes ~~In~~in Service Requests:

Under no circumstances shall the Network ~~Integration~~ Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g., the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network ~~Integration~~ Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network ~~Integration~~ Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load ~~A~~and Resource Information Updates:

The Network ~~Integration~~ Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff including~~,~~ but not limited to, any information provided under section 29.2(ix) pursuant to the Transmission Provider's planning process in Attachment ~~K~~N-1 or Attachment N-2, as applicable. The Network ~~Integration~~ Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network ~~Integration~~ Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

~~32. ADDITIONAL STUDY PROCEDURES FOR NETWORK INTEGRATION TRANSMISSION SERVICE REQUESTS~~

32 Additional Study Procedures For Network Integration Transmission Service Requests

32.1 Notice ~~Of~~of Need ~~F~~for System Impact Study:

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement ~~A~~and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission

Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures:

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify (1) any system constraints, identified with specificity by transmission element or flowgate, (2) redispatch options (when requested by an Eligible Customer) including, to the extent possible, an estimate of the cost of redispatt~~a~~ch, (3) available options for installation of automatic devices to curtail service (when requested by an Eligible Customer), and (4) additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. For customers requesting the study of redispatch options, the System Impact Study shall (1) identify all resources located within the Transmission Provider's Control Area that can significantly contribute toward relieving the system constraint and (2) provide a measurement of each resource's impact on the system constraint. If the Transmission Provider possesses information indicating that any resource outside its Control Area could relieve the constraint, it shall identify each such resource in the System Impact Study. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service

Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures:

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

32.5 Penalties for Failure to Meet Study Deadlines:

Section 19.9 defines penalties that apply for failure to meet the 60-day study completion due diligence deadlines for System Impact Studies and Facilities Studies under Part II of the Tariff. These same requirements and penalties apply to service under Part III of the Tariff.

~~33. LOAD SHEDDING AND CURTAILMENTS~~
<u>33 Load Shedding and Curtailments</u>

33.1 Procedures:

Prior to the Service Commencement Date, the Transmission Provider and the Network ~~Integration~~ Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System and on systems directly and indirectly interconnected with the Transmission Provider's Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission

Provider will notify all affected Network ~~Integration~~ Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints:

During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources of Network ~~Integration~~ Customers and Network Contract Demand Customers and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers, any Network ~~Integration~~ Customer's use of the Transmission System to serve its designated Network Load and any Network Contract Demand Customer's use of the Transmission System to serve its Network Contract Demand Points of Delivery.

33.3 Cost Responsibility ~~F~~for Relieving Transmission Constraints:

Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider, Network ~~Integration~~ Customers and Network Contract Demand Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio

Shares or contract demands, as appropriate.

33.4 Curtailments ~~Of~~of Scheduled Deliveries:

If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement or pursuant to the Transmission Loading Relief procedures specified in Attachment ~~N~~L.

33.5 Allocation ~~Of~~of Curtailments:

The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network ~~Integration~~ Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network ~~Integration~~ Customer to Curtail schedules to an extent greater than the Transmission Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding:

To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider, Network ~~Integration~~ Customers and Network Contract Demand Customers to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability:

Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network ~~Integration~~ Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers.

In the CP&L Zone and in the FPC Zone, in the event that the Network ~~Integration~~ Customer fails to respond to established Load Shedding and Curtailment procedures, the Customer shall pay, in addition to any other charges for service, a charge equal to two times the amount of transmission service which the Customer fails to curtail multiplied by the monthly charge for Network

Integration Transmission Service.

~~34. RATES AND CHARGES~~

34 Rates and Charges

The Network ~~Integration~~ Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge:

The Network ~~Integration~~ Customer whose Network Load is located in or served from the CP&L Zone shall pay a monthly Demand Charge which shall be determined by multiplying its load at the time of the monthly transmission peak times the Transmission Provider's monthly transmission rate for the CP&L Zone as specified in Attachment H.

The Network ~~Integration~~ Customer whose Network Load is located in or served from the FPC Zone shall pay a monthly Demand Charge, which shall be determined as provided in Schedules 10-A and 11.

The Network Customer whose Network Load is located in or served from the DEC Zone by facilities at or above 44 kV shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Transmission Provider's Annual Transmission Revenue Requirement determined pursuant to Schedule 10-B, Exhibit B.

A Network Customer utilizing Network Integration Transmission Service under this Tariff, Network Contract Demand Transmission Service, or Long Term Firm or Short Term Firm Point-To-Point Transmission Service in any Zone to serve Network Load located in another Zone, shall pay only the applicable charge of the Zone in which the Network Load is located.

34.2 Determination ~~Of~~of Network ~~Integration~~ Customer's Monthly Network Load:

~~The~~In the CP&L Zone and in the FPC Zone, the Network ~~Integration~~ Customer's monthly Network Load in a Zone is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) that is located in or connected to that Zone coincident with the Transmission Provider's Monthly Transmission System Peak in that Zone.

In the DEC Zone, the Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) that is located in or connected to the DEC Zone coincident with the Transmission Provider's Monthly Transmission System Peak, plus the output of the Network Customer's behind the load-meter generation at the time of the Transmission Provider's Monthly Transmission Peak.

34.3 Determination ~~Of~~of Transmission Provider's Monthly Transmission System ~~Load~~Peak:

The Transmission Provider's monthly Transmission System load in ~~a~~the CP&L Zone and in the FPC Zone is the Transmission Provider's Monthly Transmission System Peak in that Zone minus the coincident peak usage of all Firm Point-To-Point Transmission Service Customers and Network Contract Demand Transmission Customers in that Zone pursuant to Parts II and IV of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service Customers and Network Contract Demand Transmission Customers taking service in that Zone.

The Transmission Provider's Monthly Transmission System Peak in the DEC Zone is the highest hourly total (single hour coincident amount of the following: (a) the Transmission Provider's Control Area load, plus (b) the output of all behind-the-load-meter generation of Network Customers, plus (c) the amount of firm loads that have been pseudo-tied out of the Transmission Provider's Control Area, minus (d) the usage of all Point-To-Point Transmission Service customers pursuant to Part II of this Tariff, plus (e) the Reserved Capacity of all long-term Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge:

The Network ~~Integration~~ Customer shall pay a proportionate share of any redispatch costs for the Zone in which it is taking service, allocated among Network ~~Integration~~ Customers, Network Contract Demand Customers, and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network ~~Integration~~ Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network ~~Integration~~ Customer's bill for the applicable month. ~~The formulas for determining and assessing redispatch costs are set out in Attachment J.~~

34.5 Stranded Cost Recovery:

The Transmission Provider may seek to recover stranded costs from the Network ~~Integration~~ Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

~~35. OPERATING ARRANGEMENTS~~

35 Operating Arrangements

35.1 Operation Under The Network Operating Agreement:

The Network ~~Integration~~ Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement:

The terms and conditions under which the Network ~~Integration~~ Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network ~~Integration~~ Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network ~~Integration~~ Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network ~~Integration~~ Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO) as defined in 18 C.F.R. § 39.1, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G~~.~~ (in the DEC Zone, the Network Operating Agreement is Attachment E to the Form of Service Agreement for Network Integration Transmission Service (available at Attachment F-2 of this Tariff)).

35.3 Network Operating Committee:

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network ~~Integration~~ Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

Notwithstanding anything to the contrary in this or any other section of this tariff, service is no longer available to new service requests under Sections 36-46 of this tariff on or after June 14, 2008. Service availability is limited to customers with Network Contract Demand Service agreements effective on or before June 14, 2008 through the termination of such agreements.

IV. NETWORK CONTRACT DEMAND TRANSMISSION SERVICE

~~**PREAMBLE**~~
Preamble

The Transmission Provider will provide Network Contract Demand Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Contract Demand Transmission Service allows the Network Contract Demand Customer to integrate, economically dispatch and regulate multiple generating resources to serve designated loads in a manner comparable to that in which the Transmission Provider utilizes its generating units and its Transmission System to make third party sales of system power and energy. Service is available to any Transmission Customer that meets the requirements of Section 37. The provision of Network Contract Demand Transmission Service shall not cause the rates of Transmission Customers taking service under Part II or Part III of the Tariff to increase above what they would be absent the provision of service under this Part IV of the Tariff.

~~**36. NATURE OF NETWORK CONTRACT DEMAND TRANSMISSION SERVICE**~~
36 Nature of Network Contract Demand Transmission Service

36.1 Scope ~~Of~~of Service:

Network Contract Demand Transmission Service is firm transmission service that allows Network Contract Demand Customers to efficiently and economically utilize multiple generation resources to serve designated loads. The Network Contract Demand Customer taking Network Contract Demand Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

36.2 Transmission Provider Responsibilities:

The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Contract Demand Customer with Network Contract Demand Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider shall be required to file a service agreement and to take service under this Part IV of this Tariff when it uses its Transmission System in connection with wholesale sales of capacity and energy from multiple generating units on a contract demand basis.

36.3 Term:

The minimum term of Network Contract Demand Transmission Service shall be one day. The term shall be specified in the Service Agreement.

36.4 Reservation Priority:

Long-Term Network Contract Demand Transmission Service and Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis i.e., in the chronological sequence in which each Transmission Customer has reserved service. Reservations for Short-Term Network Contract Demand Transmission Service and Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following deadlines; one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the deadline, if available transmission capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service has the right of first refusal to match any longer term reservation before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service or Short-Term Network Contract Demand Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Sections 13.8 or 36.9) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service or Short-Term Network Contract Demand Transmission Service. After the conditional reservation deadline, service will commence pursuant to the terms of Part IV of the Tariff. Network Contract Demand Transmission Service will always have a reservation priority equal to that of Firm Point-To-Point Transmission Service and over that of Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Network Contract Demand Transmission Service will have equal reservation priority with Native Load Customers, Long-Term Firm Point-To-Point Customers and Network ~~Integration~~ Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

36.5 Use ~~Of~~of Network Contract Demand Transmission Service ~~By~~by ~~T~~the Transmission Provider:

The Transmission Provider will be subject to the rates, terms and conditions of Part II or Part IV of the Tariff when making Third-Party Sales. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Point-To-Point Transmission Service or Network Contract Demand Transmission Service to make Third-Party Sales.

36.6 Service Agreements:

The Transmission Provider shall offer a standard form Network Contract Demand Transmission Service Agreement (Attachment ~~K~~R) to an Eligible Customer when it submits a Completed Application for Long-Term Network Contract Demand Transmission Service. The Transmission Provider shall offer a standard form Network Contract Demand Transmission Service Agreement (Attachment R) to an Eligible Customer when it first submits a Completed Application for Short-Term Network Contract Demand Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

36.7 Transmission Customer Obligations ~~F~~for Facility Additions ~~O~~or Redispatch Costs:

In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Network Contract Demand Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network ~~Integration~~ Customers, Firm Point-To-Point Transmission Customers and other Transmission Customers taking Network Contract Demand Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 40. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 45. To the extent the Transmission Provider can relieve any system constraint more economically by redispatching the Transmission Provider's resources than through constructing Network Upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 45. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

36.8 Classification ~~Of~~of Network Contract Demand Transmission Service:

The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm capacity is to be obtained from a Network Resource pursuant to Section 39.1 shall be set forth in the Network Contract Demand Service Agreement for Long-Term Network Contract Demand Transmission Service. Each Point of Delivery at which firm capacity is reserved by the Transmission Customer shall be set forth in the Network Contract Demand Service Agreement for Long-Term Network Contract Demand Transmission Service, along with the information required by Section 37.2(iii). Points of Receipt and Points of Delivery shall be as mutually agreed upon by the Parties for Short-Term Network Contract Demand Transmission. The maximum coincident capacity reservations at all Points of Delivery during the contract term shall be the Network Contract Demand Customer's Reserved Capacity. The Network Contract Demand Customer will be billed for its Reserved Capacity under the terms of Schedule 12. The Network Contract Demand Customer shall not exceed its total capacity reserved from the Points of Receipt and shall not exceed its total capacity reserved at the Points of Delivery. In the event that a Network Contract Demand Customer (including

Third-Party Sales by the Transmission Provider) exceeds its firm Reserved Capacity at the Points of Receipt or the Points of Delivery, the Network Contract Demand Customer shall pay the rate for unauthorized use as specified in Schedule 12.

36.9 Scheduling ~~Of~~of Firm Network Contract Demand Transmission Service: Schedules for the provision of Network Contract Demand Transmission Service to the Transmission Customer's Point of Delivery must be submitted to the Transmission Provider no later than 10:00 a.m. of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that are to be delivered must be stated in increments of 1,000 kW per hour. ~~In the CP&L Zone scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and the Receiving Party also agree to the schedule modification. In the FPC Zone scheduling~~Scheduling changes will be permitted up to ten (10) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification and that the transaction can be reasonably accommodated on the transmission system. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Network Contract Demand Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

36.10 Integration ~~Of~~of Delivery Points:

Subject to the availability of transmission capacity, when the Network Contract Demand Transmission Service Customer submits its daily transmission schedule, it may schedule transmission to any Point of Delivery listed in its Application for service under this Part IV in an amount different from that set out in its Application, up to its Reserved Capacity, provided that the sum of the schedules for that day at all such Points of Delivery may not exceed the Customer's Reserved Capacity. Once scheduled, such service shall be firm transmission service for that day.

36.11 Real Power Losses:

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Contract Demand Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss ~~factor in the CP&L Zone is 2.15% and the applicable Real Power Loss~~ factors in the FPC Zone are 2.05% for delivery at transmission voltages and 3.05% for delivery at distribution voltages. Procedures for annual changes to the Real Power Loss factors in the FPC Zone are set out in Attachment ~~M~~Q.

~~37. PROCEDURES FOR INITIATING NETWORK CONTRACT DEMAND TRANSMISSION SERVICE~~

37 Procedures for Initiating Network Contract Demand Transmission Service

37.1 Condition Precedent ~~F~~for Receiving Service:

Subject to the terms and conditions of Part IV of the Tariff, the Transmission Provider will provide Network Contract Demand Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an

Application for service as provided in section 37.2, (ii) the Eligible Customer meets the creditworthiness criteria set forth in Attachment ~~L~~O, (iii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 37.3 and 38.1, (iv) the Eligible Customer executes a Service Agreement pursuant to Attachment R for service under Part IV of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission pursuant to Section 37.7, and (v) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement.

37.2 Application Procedures:

An Eligible Customer requesting Network Contract Demand Transmission Service under Part IV of the Tariff must submit an Application to the Transmission Provider. Requests for service for periods of one year or more shall be submitted at least sixty (60) days in advance of the month in which service is to commence. The Transmission Provider will consider such requests for service on shorter notice when feasible. Requests for service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS.

A Completed Application shall provide all of the information included in 18 C.F.R. § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The firm transmission capacity reserved at each Point of Delivery, and the electrical location of each ultimate load;

(iv) A description of the Network Resources that will be utilized to supply the capacity and energy that will be transmitted over the Transmission Provider's Transmission System for the lesser of the contract term or ten years, which shall include, for each Network Resource:

- Location of the generating facility
- Unit size and amount of capacity from that unit to be designated as a Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
- Any periods of restricted operations throughout the lesser of one year or the contract term
- Maintenance schedules
- Minimum loading level of unit
- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons
- Approximate variable generating cost ($/MWH) for redispatch computations
- Description of purchased power designated as a Network Resource including source of supply, Control Area location, transmission arrangements and delivery point(s) to the Transmission Provider's Transmission System;

(v) Service Commencement Date and the term of the requested Network Contract Demand Transmission Service.

The Network Contract Demand Transmission Customer shall update the information contained in its Application at least once each calendar year and when material changes occur. The Transmission Provider shall treat all information provided under this Section consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

37.3 Technical Arrangements ~~To Be~~to be Completed Prior ~~To~~to Commencement ~~Of~~of Service:

Network Contract Demand Transmission Service shall not commence until the

Transmission Provider and the Network Contract Demand Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Contract Demand Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

37.4 Deposit:

A Completed Application for Network Contract Demand Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Network Contract Demand Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 40. If a Service Agreement for Network Contract Demand Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration of the term of service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Transmission Provider's account. Notwithstanding the foregoing, the Transmission Provider shall on a non-discriminatory basis waive the requirement that a deposit accompany an Application for an Eligible Customer that has met the conditions of Sections 1.2 or 1.3 of Attachment ~~L~~O to this Tariff.

37.5 Notice ~~Of~~of Deficient Application:

If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part IV of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

37.6 Determination ~~Of~~of Available Transmission Capability:

Following receipt of a Completed Application for Network Contract Demand Transmission Service, the Transmission Provider shall make a determination of available transmission capability. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application, either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 40. Responses by the Transmission Provider must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis. A description of the Transmission Provider's specific methodology for assessing available transmission capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C-2 (FPC Zone) of the Tariff.

37.7 Execution ~~A~~and Filing ~~Of~~of Service Agreement:

Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 40 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 37.7, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another

Application after such withdrawal and termination. The Transmission Provider will file the Service Agreement in compliance with applicable Commission regulations.

37.8 Initiating Service ~~In~~in ~~T~~the Absence ~~Of An~~of an Executed Service Agreement:

If the Transmission Provider and the Transmission Customer requesting Network Contract Demand Transmission Service cannot agree on all the terms and conditions of the Network Contract Demand Transmission Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Network Contract Demand Transmission Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 37.4.

37.9 Obligation ~~To~~to Provide Transmission Service ~~T~~that Requires Expansion ~~Or~~or Modification ~~Of~~of ~~T~~the Transmission System:

If the Transmission Provider determines that it cannot accommodate a Completed Application for Network Contract Demand Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested service, provided the Transmission Customer agrees to compensate the

Transmission Provider for such costs pursuant to the terms of Section 44. The Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

37.10 Deferral ~~Of~~of Service:

The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Network Contract Demand Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

37.11 Extensions ~~F~~for Commencement ~~Of~~of Service:

The Network Contract Demand Customer can obtain up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Network Contract Demand Transmission Service for each year or fraction thereof. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Point-To-Point Transmission Service or Network Contract Demand Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Network Contract Demand transmission rate for its Reserved Capacity concurrent with the new Service Commencement

Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

37.12 Changes ~~In~~in Service Requests:

Under no circumstances shall the Network Contract Demand Customer's decision to cancel or delay the commencement of Network Contract Demand Transmission Service in any way relieve the Network Contract Demand Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Contract Demand Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Contract Demand Transmission Service in a non-discriminatory manner.

~~38. TRANSMISSION CUSTOMER RESPONSIBILITIES~~

38 Transmission Customer Responsibilities

38.1 Network Customer Facilities:

The provision of Network Contract Demand Transmission Service shall be conditioned upon the Network Contract Demand Customer's constructing, maintaining and operating the facilities on its side of each Point of Delivery necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Contract Demand Customer. The Network Contract Demand Customer shall be solely responsible for constructing or installing all facilities on the Network Contract Demand Customer's side of each such Point of Delivery.

38.2 Transmission Customer Responsibility ~~F~~for Third-Party Arrangements:

Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part IV of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

~~39. DESIGNATION OF NETWORK RESOURCES~~

39 Designation Of Network Resources

39.1 Limitation ~~On~~on Designation ~~Of~~of Network Resources:

The Network Contract Demand Customer must demonstrate that it owns generation or has committed to purchase or has leased generation pursuant to an executed contract, that can be called upon to meet the Customer's Network Contract Demand on a non-interruptible basis in order to designate such generation as a Network Resource for Network Contract Demand Transmission Service. Alternatively, the Network Contract Demand Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part IV of the Tariff.

39.2 Transmission Arrangements ~~F~~for Network Resources Not Physically Interconnected With ~~T~~the Transmission Provider:

The Network Contract Demand Customer shall provide be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission

System. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

39.3 Termination ~~Of~~of Network Resources:

The Network Contract Demand Customer may terminate the designation of all or part of a generating resource as a Network Resource at any time but should provide notification to the Transmission Provider as soon as reasonably practicable.

39.4 Operation ~~Of~~of Network Resources:

The Network Contract Demand Customer shall not operate its designated Network Resources located in the Network Contract Demand Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its Network Contract Demand and its Network Load under Part III plus non-firm sales delivered pursuant to Part II of the Tariff, plus losses. This limitation shall not apply to changes in the operation of Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System.

39.5 Network Contract Demand Customer Redispatch Obligation:

As a condition to receiving Network Contract Demand Transmission Service, the Network Contract Demand Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 42.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Integration Transmission Service

Customers, Network Contract Demand Customers, and the Transmission Provider.

39.6 Use ~~Of~~of Interface Capacity ~~By~~by ~~T~~the Network Customer:

There is no limitation upon a Network Contract Demand Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Contract Demand Customer's Network Resources with its Points of Delivery.

~~40. ADDITIONAL STUDY PROCEDURES FOR NETWORK CONTRACT DEMAND TRANSMISSION SERVICE REQUESTS~~

40 Additional Study Procedures for Network Contract Demand Transmission Service Requests

40.1 Notice ~~Of~~of Need ~~F~~for System Impact Study:

After receiving a request for Network Contract Demand Transmission Service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

40.2 System Impact Study Agreement Aand Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

40.3 System Impact Study Procedures:

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

40.4 Facilities Study Procedures:

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

40.5 Facilities Study Modifications:

Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part IV of the Tariff.

40.6 Due Diligence ~~In~~in Completing New Facilities:

The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Network Contract Demand Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

40.7 Partial Interim Service:

If the Transmission Provider determines that it will not have adequate transmission capability to satisfy the full amount of a Completed Application for Network Contract Demand Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Network Contract Demand Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Network Contact Demand Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

40.8 Coordination ~~Of~~of Third-Party System Additions:

In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part IV of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

40.9 Expedited Procedures ~~F~~for New Facilities:

In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff.

In order to exercise this option, the Eligible Customer shall request in writing an Expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

~~**41. PROCEDURES IF THE TRANSMISSION PROVIDER IS UNABLE TO COMPLETE NEW TRANSMISSION FACILITIES FOR NETWORK CONTRACT DEMAND TRANSMISSION SERVICE**~~

41 Procedures if the Transmission Provider is Unable to Complete New Transmission Facilities for Network Contract Demand Transmission Service

41.1 Delays ~~In~~in Construction ~~Of~~of New Facilities:

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Network Contract Demand Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Customer of such delays, convene a technical meeting with the Customer to evaluate the alternatives available to the Customer. The Transmission Provider also shall make available to the Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Customer to evaluate any alternatives.

41.2 Alternatives ~~To~~to ~~T~~the Original Facility Additions:

When the review process of Section 41.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Network Contract Demand Customer. If, upon review of any alternatives, the Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Network Contract Demand Transmission Service. If the alternative approach solely involves Firm or Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Customer disagrees, the Customer may seek relief under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

41.3 Refund Obligation ~~F~~for Unfinished Facility Additions:

If the Transmission Provider and the Network Contract Demand Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part IV of the Tariff, the obligation to provide the requested Firm Network Contract Demand Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulation 18 C.F.R. § 35.19a(a)(2)(iii). However, the Network Contract Demand Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

~~42. LOAD SHEDDING AND CURTAILMENTS~~
42 Load Shedding and Curtailments

42.1 Procedures:

Prior to the Service Commencement Date, the Transmission Provider and the Network Contract Demand Customer shall establish Load Shedding and Curtailment procedures pursuant to a Network Operating Agreement with the objective of responding to contingencies on the Transmission System and on systems directly or indirectly interconnected with the Transmission Provider's Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Contract Demand Customers in a timely manner of any scheduled Curtailment.

42.2 Transmission Constraints:

During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources of Network Integration Transmission Customers and Network Contract Demand Transmission Customers and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers, any Network Integration Transmission Customer's use of the Transmission System to serve its designated Network Load and any Network Contract Demand Customer's use of the Transmission System to serve its Network Contract Demand Points of Delivery.

42.3 Cost Responsibility ~~F~~for Relieving Transmission Constraints:

Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider, Network Integration Transmission Customers and Network Contract Demand Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares or contract demands, as appropriate.

42.4 Curtailments ~~Of~~of Scheduled Deliveries:

If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement or pursuant to the Transmission Loading Relief procedures specified in Attachment ~~N~~L.

42.5 Allocation ~~Of~~of Curtailments:

In the event that a Curtailment on the Transmission Provider's Transmission

System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Integration Customers, Network Contract Demand Transmission Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service, Network Contract Demand Transmission Service from secondary generating resources and to secondary Points of Receipt pursuant to Sections 43.1 and 43.2, secondary service pursuant to Section 28.4 and service at secondary Points of Receipt and Delivery pursuant to Section 22.1 shall be subordinate to Network Contract Demand Transmission Service.

42.6 Load Shedding:

To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider, the Network Integration Customer and the Network Contract Demand Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

42.7 System Reliability:

Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Contract Demand Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Contract Demand Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Contract Demand Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Contract Demand Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Contract Demand Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments. In the event that a Network Contract Demand Customer fails to implement a Curtailment within ten minutes as required by the Transmission Provider the Customer shall pay, in addition to any other charges for service, a charge equal to two times the amount of transmission service which the Customer fails to curtail multiplied by the maximum charge for Network Contract Demand Transmission Service for the lesser of the transaction term or one month.

~~**43. CHANGES IN SERVICE SPECIFICATIONS**~~
43 Changes In Service Specifications

43.1 Secondary Service:

The Network Contract Demand Transmission Customer may use the Transmission Provider's Transmission System to deliver energy to its Points of Delivery from generating resources that have not been designated as Network Resources in its Application. Such energy shall be transmitted, on an as-available basis, at no additional charge, provided that the deliveries to the Points of Delivery do not exceed the Reserved Capacity. Deliveries from alternate generating resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

43.2 Non-Firm Service ~~At~~at Secondary Points ~~Of~~of Delivery:

The Network Contract Demand Transmission Customer may request the Transmission Provider to provide transmission service on a non-firm basis to Delivery Points other than those specified in the Service Agreement ("Secondary Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Network Contract Demand Transmission Service charge, executing a new Service Agreement or filing a new Application, subject to the following conditions.

(a) Service provided to Secondary Delivery Points will be non-firm only, on an as-available basis, and will not displace any firm or non-firm service reserved or scheduled by third parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Network Contract Demand Transmission Service provided to the Transmission Customer at any time at all Points of Delivery shall not exceed the Reserved Capacity in the relevant Service Agreement under which Network Contract Demand Transmission Service is being provided.

(c) The Transmission Customer shall retain its right to schedule Network Contract Demand Transmission Service at the Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

43.3 Modification ~~On A~~on a Firm Basis:

Any request by a Network Contract Demand Transmission Customer to modify its Network Resources and/or Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 37 hereof, except that such Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Network Contract Demand Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

~~44. SALE OR ASSIGNMENT OF TRANSMISSION SERVICE~~
44 Sale or Assignment of Transmission Service

44.1 Procedures ~~F~~for Assignment ~~Or~~or Transfer ~~Of~~of Service:

Subject to Commission approval of any necessary filings, a Network Contract Demand Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost capped at the Transmission Provider's cost of expansion. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. A Reseller should notify the Transmission Provider as soon as possible after any assignment or transfer of service occurs but in any event, notification must be provided prior to any provision of service to the Assignee. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Sections 43.1, 43.2 and 43.3.

44.2 Limitations ~~On~~on Assignment ~~Or~~or Transfer ~~Of~~of Service:

If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Parties through an amendment to the Service Agreement.

44.3 Information ~~On~~on Assignment ~~Or~~or Transfer ~~Of~~of Service:

In accordance with Section 4, Resellers may use the Transmission Provider's OASIS to post transmission capacity available for resale.

~~**45. RATES AND CHARGES**~~

45 Rates and Charges

The Network Contract Demand Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

45.1 Demand Charge:

The Network Contract Demand Customer shall pay Demand Charges as determined pursuant to Schedule 12.

45.2 Compensation ~~F~~for New Facilities ~~A~~and Redispatch Costs:

Whenever a System Impact Study performed by the Transmission Provider for a Transmission Customer under Section 40 in connection with the provision of Network Contract Demand Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved more economically by redispatching the Transmission Provider's resources than by building new facilities or upgrading existing facilities to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy. To the extent that the Transmission Provider incurs an obligation to the Network Contract

Demand Customer for redispatch costs in accordance with Section 39.5, such amounts shall be credited against the Network Contract Demand Customer's bill for the applicable month. ~~The formula for determining and assessing redispatch costs is set out in Attachment J.~~

45.3 Redispatch Charge:

The Network Contract Demand Customer shall pay a proportionate share of any redispatch costs allocated among Network Integration Customers, Network Contract Demand Customers and the Transmission Provider pursuant to Section 42. To the extent that the Transmission Provider incurs an obligation to the Network Contract Demand Customer for redispatch costs in accordance with Section 42, such amounts shall be credited against the Network Contract Demand Customer's bill for the applicable month. ~~The formulas for determining and assessing redispatch costs are set out in Attachment J.~~

45.4 Stranded Cost Recovery:

The Transmission Provider may seek to recover stranded costs from the Network Contract Demand Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

~~46. OPERATING ARRANGEMENTS~~

46 Operating Arrangements

46.1 Operation Under ~~T~~the Network Operating Agreement:

The Network Contract Demand Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

46.2 Network Operating Agreement:

The terms and conditions under which the Network Contract Demand Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part IV of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Contract Demand Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network Contract Demand Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 42, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part IV of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Contract Demand Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the regional reliability council, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and regional reliability council requirements. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

46.3 Network Operating Committee:

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Contract Demand Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Charges:

The charge for Scheduling, System Control and Dispatch Service shall be based on the Zone in which the load is located or, if the energy is transmitted to an interface with another transmission provider, the last Zone in which transmission service is reserved by the Transmission Customer, except in the case of energy being transmitted to serve Network Load under Part III of this Tariff in which case the applicable charge will be under Section 34 of the Tariff.

The applicable zonal charges are set out below.

A. CP&L Zone

A.1.1 The base rates for scheduling and dispatch services are as follows:

A.1.1.1 For Point-to-Point service~~ or Network Contract Demand Service~~ reserved for an Annual Period or a Monthly Period, the charge for service supplied in a Monthly Period shall not exceed the Transmission Customer's Monthly Period transmission reservation multiplied by $36.50 per MW-month. For a Network Integration Transmission Service Customer, the charge for service supplied in a month shall be the Customer's load coincident with the hour of the CP&L monthly Transmission System Peak during the month, multiplied by $36.50 per MW.

A.1.1.2 For service reserved for a Weekly Period, the charge for service supplied in a Weekly Period shall not exceed the Transmission Customer's Weekly Period transmission reservation multiplied by $8.42 per MW-week. However, the sum of the charges for Weekly Period service supplied in a Monthly Period shall not exceed the charges for the same amount of capacity reserved for a Monthly Period.

A.1.1.3 For service reserved for a Daily Period, the charge for service supplied in a Daily Period shall not exceed the Transmission Customer's Daily Period transmission reservation multiplied by $1.68 per MW-day for ~~On~~on-~~P~~peak ~~D~~days and $1.20 per MW-day for ~~O~~off-~~P~~peak ~~D~~days. However, the sum of the charges for Daily Period service supplied in a Weekly Period shall not exceed the charges for the same amount of capacity reserved for a Weekly Period.

A.1.1.4 For service reserved for an Hourly Period, the charge for service supplied in an Hourly Period shall not exceed the Transmission Customer's Hourly Period transmission reservation multiplied by $0.11 per MW-hour for ~~On~~on-~~P~~peak

~~H~~hours and $0.05/MW-hour for ~~O~~off-~~P~~peak ~~H~~hours. However, the sum of the charges for Hourly Period service supplied in a Daily Period shall not exceed the charges for the same amount of capacity reserved for a Daily Period.

A.1.2 The billing determinant shall be the Transmission Customer's Reserved Capacity for Point-To-Point Transmission Service or ~~Network Contract Demand Transmission Service or~~ the Transmission Customer's Network Load for the applicable month for Network Integration Transmission Service.

B. FPC Zone

B.1.1 The charge for Scheduling, System Control and Dispatch Service is

B.1.1.1 $67/MW month for service in a Monthly Period or an Annual Period.

B.1.1.2 $15.57/MW week for service in a Weekly Period.

B.1.1.3 $3.11/MW day, for service in a Daily Period for ~~On~~on-~~P~~peak ~~D~~days and $2.22/MW day for ~~O~~off-~~P~~peak ~~D~~days, provided that the maximum charge in any Weekly Period shall be no greater than the product of the maximum service reserved in any Daily Period in that Weekly Period and the maximum charge for Weekly Period service.

B.1.1.4 $0.19/MW hour for service in an Hourly Period for ~~On~~on-~~P~~peak ~~H~~hours and $0.09/MW hour for ~~O~~off-~~P~~peak ~~H~~hours. The maximum charge in any Daily Period shall not exceed the product of the maximum service reserved in any Hourly Period in that Daily Period and the maximum charge for Daily Period service; and the maximum charge in any Weekly Period shall not exceed the product of the maximum service reserved in any Hourly Period in that Weekly Period and the maximum charge for Weekly Period service.

B.1.2 The billing determinant shall be the Transmission Customer's Reserved Capacity for Point-To-Point Transmission Service or Network Contract Demand Transmission Service or the Transmission Customer's Network Load for the applicable month for Network Integration Transmission Service.

C. DEC Zone

C.1.1 The Point to Point Transmission Service Customer shall compensate the Transmission Provider each month for Scheduling, System Control and Dispatch Service at the sum of the applicable charges set forth below:

C.1.1.1 For Yearly Service, one-twelfth of the Annual Schedule 1 Rate determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per year (expressed in kW).

C.1.1.2 For Monthly Service, the Monthly Schedule 1 Rate determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per month (expressed in kW).

C.1.1.3 For Weekly Service, the Weekly Schedule 1 Rate determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per week (expressed in kW).

C.1.1.4 For Daily On-Peak Service, the Daily Schedule 1 On-Peak Rate determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per day (expressed in kW).

C.1.1.5 For Daily Off-Peak Service, the Daily Schedule 1 Off-Peak Rate determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per day (expressed in kW).

C.1.1.6 For Hourly On-Peak Service, the Hourly Schedule 1 On-Peak Rate determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per hour (expressed in kW).

C.1.1.7 For Hourly Off-Peak Service, the Hourly Schedule 1 Off-Peak Rate determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per hour (expressed in kW).

The Schedule 1 Annual Revenue Requirement for purposes of Scheduling, System Control and Dispatch Service for Network Integration Transmission Service shall be as determined in Schedule 10-B, Exhibit B. The Network Integration Transmission Service Customer shall compensate the Transmission Provider each month at the Transmission Customer's monthly Load Ratio Share calculated on a rolling twelve month basis multiplied by one-twelfth of the annual revenue requirements as determined in Schedule 10-B, Exhibit B.

Exhibit A to Schedule 1

Scheduling, System Control and Dispatch Service Rates in the DEC Zone

1. The Annual Schedule 1 Rate for a calendar year is equal to A / B, where:

   - A = the Schedule 1 Annual Revenue Requirement for the calendar year as determined in Schedule 10-B, Exhibit B

   - B = the average of the Transmission Provider's twelve Monthly Transmission System Peaks (expressed in kilowatts) for the calendar year as defined in Section 34.3 of the Tariff

2. The Monthly Schedule 1 Rate is equal to the Annual Schedule 1 Rate divided by twelve (12).

3. The Weekly Schedule 1 Rate is equal to the Annual Schedule 1 Rate divided by fifty-two (52).

4. The Daily Schedule 1 On-Peak Rate is equal to the Weekly Schedule 1 Rate divided by five (5).

5. The Daily Schedule 1 Off-Peak Rate is equal to the Weekly Schedule 1 Rate divided by seven (7).

6. The Hourly Schedule 1 On-Peak Rate is equal to the Daily Schedule 1 On-Peak Rate divided by sixteen (16).

7. The Hourly Schedule 1 Off-Peak Rate is equal to the Daily Schedule 1 Off-Peak Rate divided by twenty-four (24).

SCHEDULE 2

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION OR OTHER SOURCES SERVICE

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator. Although the Transmission Customer is required to take this ancillary service from the Transmission Provider, the Transmission Customer may reduce the charge for this service to the extent that the Transmission Customer can supply reactive power and voltage control to the Transmission Provider's Transmission System.

Charges:

The charge for Reactive Supply and Voltage Control from Generation Sources Service shall be based on the Zone in which the energy being transmitted is consumed or, if the energy is transmitted to an interface with another transmission provider, the Zone in which transmission service is last provided by the Transmission Provider, except in the case of energy being transmitted to serve Network Load under Part III of this Tariff in which case the applicable charge will be under Section 34 of the Tariff.

The applicable zonal charges are set out below.

A. CP&L Zone

A.2.1 The applicable rates for Reactive Supply and Voltage Control from Generation Sources (RSVC) Service shall be as follows:

A.2.1.1 For service reserved for an Annual Period or a Monthly Period, the rate shall not exceed $88.80 per MW-month.

A.2.1.2 For service reserved for a Weekly Period, the rate shall not exceed $20.49 per MW-week.

A.2.1.3 For service reserved for a Daily Period, the rate shall not exceed $4.10 per MW-day for ~~On~~on-~~P~~peak ~~D~~days and $2.93 per MW-day for ~~O~~off-~~P~~peak ~~D~~days.

A.2.1.4 For service reserved for an Hourly Period, the rate shall not exceed $0.26 per MW-hour for ~~On~~on-~~P~~peak ~~H~~hours and $0.12 per MW-hour for ~~O~~off-~~P~~peak ~~H~~hours.

A.2.2 The charge for RSVC Service required for a customer will be as follows:

A.2.2.1 For a Network Integration Transmission Service customer, the charge in a month shall be the customer's load coincident with the hour of the CP&L Monthly Transmission System Peak during the month multiplied by the monthly rate for RSVC Service.

A.2.2.2 For a Point-to-Point ~~or Network Contract Demand~~ reservation, the charge shall be as follows:

A.2.2.2.1 For service reserved for an Annual Period or a Monthly Period, the charge for service supplied in a Monthly Period shall be the customer's Monthly Period transmission reservation multiplied by the Monthly Period rate for RSVC Service.

A.2.2.2.2 For service reserved for a Weekly Period, the charge for service supplied in a Weekly Period shall be the customer's Weekly Period transmission reservation multiplied by the Weekly Period rate for RSVC Service. However, the sum of the charges for Weekly Period service supplied in a Monthly Period shall not exceed the charges for the same amount of capacity reserved for a Monthly Period.

A.2.2.2.3 For service reserved for a Daily Period, the charge for service supplied in a Daily Period shall be the Customer's Daily Period transmission reservation multiplied by the Daily Period rate for RSVC Service. However, the sum of the charges for Daily Period service supplied in a Weekly Period shall not exceed the charges for the same amount of capacity reserved for a Weekly Period.

A.2.2.2.4 For service reserved for an Hourly Period, the charge for service supplied in an Hourly Period shall be the Customer's Hourly Period transmission reservation multiplied by the Hourly Period rate for RSVC Service. However, the sum of the charges for Hourly Period service supplied in a Daily Period shall not exceed the charges for the same amount of capacity reserved for a Daily Period.

A.2.3 A Transmission Customer purchasing Reactive Supply and Voltage Control from Generating Sources Service shall purchase an amount of service equal to the Transmission Customer's Reserved Capacity for ~~Network Contract Demand Transmission Service or~~ Point-To-Point Transmission Service or the Transmission Customer's Network Load for the applicable month for Network Integration Transmission Service.

B. FPC Zone

B.2.1 A Transmission Customer purchasing Reactive Supply and Voltage Control from Generating Sources Service shall purchase an amount of service equal to the Transmission Customer's Reserved Capacity for Network Contract Demand Transmission Service or Point-To-Point Transmission Service or the Transmission Customer's Network Load for the applicable month for Network Integration Transmission Service.

B.2.2 The charge for Reactive Supply and Voltage Control from Generation Sources Service is no greater than:

B.2.2.1 $110/MW month for service for an Annual Period or a Monthly Period.

B.2.2.2 $25.40/MW week for service for a Weekly Period.

B.2.2.3 $5.08/MW day for service in a Daily Period for ~~On~~on-~~P~~peak ~~D~~days and $3.62/MW day for ~~O~~off-~~P~~peak ~~D~~days; provided that the maximum charge in any Weekly Period shall be no greater than the product of the maximum service reserved in any Daily Period in that Weekly Period and the maximum charge for Weekly Period service.

B.2.2.4 $0.32/MW hour for service in an Hourly Period for ~~On~~on-~~P~~peak ~~H~~hours and $0.15/MW hour for ~~O~~off-~~P~~peak ~~H~~hours. The maximum charge in any Daily Period shall not exceed the product of the maximum service reserved in any Hourly Period in that Daily Period and the maximum charge for Daily Period service; and the maximum charge in any Weekly Period shall not exceed the product of the maximum service reserved in any Hourly Period in that Weekly Period and the maximum charge for Weekly Period service.

C. DEC Zone

C.2.1 The Point to Point Transmission Service Customer shall compensate the Transmission Provider each month for Reactive Supply and Voltage Control from Generation Sources Service at the sum of the applicable charges set forth below:

C.2.1.1 For Monthly Service, $.20/kW of Reserved Capacity per month.

C.2.1.2 For Weekly Service, $.046/kW of Reserved Capacity per week.

C.2.1.3 For Daily On Peak Service, $.009/kW of Reserved Capacity per on peak days.

C.2.1.4 For Daily Off Peak Service, $.0066/kW of Reserved Capacity per off peak days.

C.2.1.5 For Hourly On Peak Service, $.0006/kW of Reserved Capacity per on peak hours.

C.2.1.6 For Hourly Off Peak Service, $.00027/kW of Reserved Capacity per off peak hours.

The annual revenue requirements for purposes of Reactive Supply and Voltage Control from Generation Sources Service for Network Integration Transmission Service shall be $40,152,000. The Network Integration Transmission Service Customer shall compensate the Transmission Provider each month at the sum of the Transmission Customer's monthly Load Ratio Share calculated on a rolling twelve month basis multiplied by one-twelfth of the annual revenue requirements of $40,152,000.

SCHEDULE 3

~~Regulation and Frequency Response Service~~

REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. If the Transmission Customer elects to provide this service itself or by contracting with a third party, the Transmission Customer or the third party provider shall meet the applicable NERC, FRCC, SERC, and VACAR requirements for this service.

Charges:

The charge for Regulation and Frequency Response Service shall be based on the Zone in which the load is located. The applicable zonal charges are set out below.

A. CP&L Zone

A.3.1 A Transmission Customer purchasing Regulation and Frequency Response Service will be required to purchase an amount of Customer Regulation and Frequency Response Capacity (TCLoad) equal to 1.2 percent of the Transmission Customer's reserved capacity for Point-to-Point ~~Transmission Service or Network Contract Demand~~ Transmission Service or 1.2 percent of the Network Integration Transmission Customer's maximum hourly network load responsibility during each service period (e.g., Daily Period or Weekly Period) for service periods of less than one month or 1.2 percent of the Network Integration Transmission Customer's hourly network load coincident with the hour of the Transmission Provider's monthly transmission peak for Network Integration Transmission Customers subscribing to service periods of a month or longer. The billing determinants for this service shall be reduced by any portion of the 1.2 percent purchase obligation that a Transmission Customer obtains from third parties or supplies itself; provided, however, that the Transmission Customer shall be responsible for installing any telemetering or other equipment necessary for multiple parties to provide Regulation and Frequency Response Service in a manner that is consistent with Good Utility Practice.

A.3.2 The maximum rates for Regulation and Frequency Response (RFR) Service shall be as follows for the service periods indicated:

a. For service provided for an Annual or Monthly Period, the rate shall not exceed $3,960 per MW-month.

b. For service provided for a Weekly Period, the rate shall not exceed $913.85 per

MW-week.

c. For service provided for a Daily Period, the rate shall not exceed $182.77 per MW-day for ~~O~~on-~~P~~peak ~~D~~days and $130.55 per MW-day for ~~O~~off-~~P~~peak ~~D~~days.

A.3.3 The charge for Regulation and Frequency Response Service will be as follows:

RFRC = RFRR x TCLoad

Where: RFRC is the charge the Transmission Customer would pay for Regulation and Frequency Response Service.

RFRR is the applicable Regulation and Frequency Response capacity rate.

TCLoad is 1.2% of Transmission Customer's load or reservation for which CP&L is supplying Regulation and Frequency Response Service during the service period as determined in Section A.3.1.

1.2% is the percentage of regulating reserves that CP&L carries for the CP&L system.

A.3.3.1 The sum of the charges for Weekly Period service supplied during a Monthly Period shall not exceed the charges for the same amount of TCLoad purchased for a Monthly Period.

A.3.3.2 The sum of the charges for Daily Period service supplied during a Weekly Period shall not exceed the charges for the same amount of TCLoad purchased for a Weekly Period.

A.3.4 Regulation Service with Customer Dispatch of Customer Resource

A.3.4.1 A Transmission Customer who wishes to assume dispatch responsibilities for all or a portion of the Transmission Customer's resource(s) must demonstrate that it supplies such service in accordance with NERC and SERC criteria. The Transmission Customer will be charged as stated in Section A.3.3 above. If

CP&L reasonably believes that the Transmission Customer's Regulation and Frequency Response requirement is excessive, such that the Transmission Customer will impose costs that are substantially dissimilar to those imposed by other Transmission Customers and CP&L, CP&L may file for approval of a separate Regulation and Frequency Response charge, pursuant to § 205 of the Federal Power Act; such separate charge to be set out in the Transmission Customer's Service Agreement. CP&L will provide the requested transmission service to the Transmission Customer pending a final determination as to the proposed charges.

A.3.4.2 Telemetry of load and generation information to CP&L's Energy Control Center (ECC), or its successor facility, for the purposes of control and metering of services is required for Transmission Customer dispatch of resources. The Transmission Customer may provide a means to minimize the amount of Regulation and Frequency Response Service required through the installation and use of automatic generating controls and load control computers at the Transmission Customer's facilities to match the Transmission Customer's generation and load in real time. CP&L will make reasonable efforts to accommodate such Transmission Customer equipment. Expenses associated with telemetry of information to the ECC and any other accommodation of a Transmission Customer's control system shall be covered under Direct Assignment Facilities. The Transmission Customer's load and resource energy shall be telemetered and measured regardless of whether the Transmission Customer purchases Regulation and Frequency Response Service from CP&L

or contracts with another entity for such service unless otherwise mutually agreed upon by CP&L and the Transmission Customer in which case such arrangements will be included in the Service Agreement. Continuous measurement is necessary to ensure that CP&L is compensated for any Regulation and Frequency Response Service provided, either as a contracted service or as a service provided to make up for loss of such service from another source.

A.3.5 Regulation Service with Dynamic Scheduling

A.3.5.1 In some instances a Transmission Customer may have a resource supply agreement which permits all or a portion of its load to be served from another control area. In such instances and with the cooperation and assistance of such control area operator, the Transmission Customer may employ dynamic scheduling to serve its load from such control area provided the required technical and operating agreements can be reached and approved by the applicable regulatory agencies. For a Transmission Customer with dynamic scheduling of all or a portion of its load to another control area, the following cost allocations shall apply for Regulation and Frequency Response service:

A.3.5.1.1 For normal operation, Regulation and Frequency Response service is not required for a Transmission Customer with dynamic scheduling as described herein, provided that telemetry is operational and transmission paths are available to the supplying control area.

A.3.5.1.2 For telemetry failures as defined in the Transmission Customer's

Service Agreement, the Transmission Customer must rely on manually implemented power schedules to meet its estimated load. The Service Agreement shall set out the terms and conditions under which CP&L will, upon such telemetry system failure, provide the Transmission Customer with Regulation and Frequency Response Service at those telemetry point(s) experiencing the failure.

A.3.5.1.3 Telemetry of load and generation information to the ECC, for the purposes of control and metering of services is required for dynamic scheduling of resources. CP&L will make reasonable efforts to accommodate such Transmission Customer equipment required for dynamic scheduling. Expenses associated with telemetry of information to the ECC and any other accommodation of a Transmission Customer's control system shall be covered under Direct Assignment Facilities.

B. FPC Zone

B.3.1 The charge for Regulation and Frequency Response Service is no greater than:

B.3.1.1 $4,699/MW month for service in an Annual Period or a Monthly Period.

B.3.1.2 $1,084.40/MW week for service in a Weekly Period.

B.3.1.3 $216.88/MW day for service in a Daily Period for ~~On~~on-~~P~~peak ~~D~~days and $154.49/MW day for ~~O~~off-~~P~~peak ~~D~~days, provided that the maximum charge in any Weekly Period shall be no greater than the product of the maximum service reserved in any Daily Period in that Weekly Period and the maximum charge for Weekly Period service.

B.3.1.4 $13.55/MW hour for service in an Hourly Period for ~~On~~on-~~P~~peak ~~H~~hours and $6.44/MW hour for ~~O~~off-~~P~~peak ~~H~~hours. The maximum charge in any Daily Period shall not exceed the product of the maximum service reserved in any Hourly Period in that Daily Period and the maximum charge for Daily Period service; and the maximum charge in any Weekly Period shall not exceed the product of the maximum service reserved in any Hourly Period in that Weekly Period and the maximum charge for Weekly Period service.

B.3.2 A Transmission Customer purchasing Regulation and Frequency Response Service shall purchase an amount of service equal to 1.5 percent of the Transmission Customer's Reserved Capacity for Network Contract Demand Transmission Service or Point-To-Point Transmission Service or 1.5 percent of the Transmission Customer's Network Load for the applicable month for Network Integration Transmission Service. The billing determinants for this service shall be reduced by any portion of the 1.5 percent purchase obligation that Transmission Customer obtains from third parties or supplies itself.

B.3.3 Self-Supply of Service

A Transmission Customer located in the Transmission Provider's Control Area shall purchase Regulation and Frequency Response Service from the Transmission Provider unless it provides the service itself or purchases it from a third party through automatic generation control or dynamic scheduling.

C. DEC Zone

C.3.1 The Point to Point Transmission Service Customer shall compensate the Transmission Provider each month for Regulation and Frequency Response Service provided by the Transmission Provider at the sum of the applicable charges set forth below:

C.3.1.1 For Monthly Service, $.038/kW of Reserved Capacity per month.

C.3.1.2 For Weekly Service, $.009/kW of Reserved Capacity per week.

C.3.1.3 For Daily On Peak Service, $.002/kW of Reserved Capacity per on peak days.

C.3.1.4 For Daily Off Peak Service, $.0013/kW of Reserved Capacity per off peak days.

C.3.1.5 For Hourly On Peak Service, $.0001/kW of Reserved Capacity per on peak hours.

C.3.1.6 For Hourly Off Peak Service, $.00005/kW of Reserved Capacity per off peak hours.

The annual revenue requirements for purposes of Regulation and Frequency Response Service for Network Integration Transmission Service shall be $7,628,880. The Network Integration Transmission Service Customer shall compensate the Transmission Provider each month for Regulation and Frequency Response Service provided by the Transmission Provider at the sum of the Transmission Customer's monthly Load Ratio Share calculated on a rolling twelve month basis multiplied by one-twelfth of the annual revenue requirements of $7,628,880.

SCHEDULE 3A

Generator Regulation Service

[FPC Zone ~~Only~~]

Generator Regulation Service is necessary to provide for on-line generation which is available to respond to schedule ramps required to start, change or end a transmission schedule to another Control Area and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Generator Regulation Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic on-line generation equipment) as necessary to follow the moment-by-moment differences between the generator's output and the ramping transmission schedule. The obligation to provide on-line resources to implement schedules with other Control Areas lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when transmission service is provided for a generator located in the Control Area that is not identified in Appendix 1 to this Schedule to an interface with another Control Area. The Transmission Customer that schedules service from a generator located in the Transmission Provider's Control Area that is not identified in Appendix 1 to an interface with another Control Area must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Generator Regulation Service obligation. The amount of and charges for Generator Regulation Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Charges:

The charge for Generator Regulation Service is no greater than:

$4,699/MW month for service in an Annual Period or a Monthly Period.

$1,084.40/MW week for service in a Weekly Period.

$216.88/MW day for service in a Daily Period for ~~On~~on-~~P~~peak ~~D~~days and $154.49/MW day for ~~O~~off-~~P~~peak ~~D~~days; provided that the maximum charge in any Weekly Period shall be no greater than the product of the maximum service reserved in any Daily Period in that Weekly Period and the maximum charge for Weekly Period service.

$13.55/MW hour for service in an Hourly Period for ~~On~~on-~~P~~peak ~~H~~hours and $6.44/MW hour for ~~O~~off-~~P~~peak ~~H~~hours. The maximum charge in any Daily Period shall not exceed the product of the maximum service reserved in any Hourly Period in that Daily Period and the maximum charge for Daily Period service; and the maximum charge in any Weekly Period shall not exceed the product of the maximum service reserved in any Hourly Period in that Weekly Period and the maximum charge for Weekly Period service.

A Transmission Customer purchasing Generator Regulation Service shall purchase an amount of service equal to 1.5 percent of the Transmission Customer's Reserved Capacity for Network Contract Demand Transmission Service or Point-To-Point Transmission Service or 1.5 percent of the Transmission Customer's Network Load for the applicable month for Network Integration Transmission Service. The billing determinants for this service shall be reduced by any portion of the 1.5 percent purchase obligation that Transmission Customer obtains from third parties or supplies itself.

Self-Supply of Service

A Transmission Customer located in the Transmission Provider's Control Area shall purchase Generator Regulation Service from the Transmission Provider unless it provides the service itself or purchases it from a third party through automatic generation control or dynamic scheduling.

Appendix 1 to Schedule 3A

Generators in the FPC Zone for Which Generator Regulation Service Is Provided Pursuant to a Separate Agreement

The Transmission Provider has entered into agreements with the following generators that provide for the continuous balancing of generation with energy schedules to other Control Areas:

Orange Cogeneration Limited Partnership

Central Power & Lime, Inc.

City of Tallahassee (C.H. Corn Hydro)

Southeastern Power Administration (Woodruff Dam)

SCHEDULE 4

~~**Energy Imbalance Service**~~

ENERGY IMBALANCE SERVICE

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly energy imbalances under this Schedule or a penalty for hourly generator imbalances under Schedule ~~9~~13 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.

4.1 The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of incremental or decremental cost; (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the

Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of incremental cost or 75 percent of decremental cost.

4.2 CP&L Zone and FPC Zone

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched for any purpose, e.g., to supply the Transmission Provider's Native Load Customers, correct imbalances, or make off-system sales, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable. Start-up cost will also include the cost to cycle a unit back on-line that was removed from service to accommodate an excess Energy Imbalance purchase. CP&L and FPC utilize the PCI GenTrader generation resource optimization model to determine the incremental and decremental cost. CP&L and FPC use actual generation and load parameters and spot value of relevant commodities as data for this optimization model.

~~4.3~~4.2.1 Credits for Energy Imbalance Revenues in the CP&L Zone and FPC Zone

The Transmission Provider will credit revenues that it receives in excess of the incremental costs it incurs to accommodate energy imbalances ("penalty revenues") to all non-offending Transmission Customers (including Affiliated Transmission Customers) and to the Transmission Provider on behalf of its own customers (Native Load Customers). The credits shall be calculated and allocated as set out below.

The penalty revenues for which the Transmission Provider provides credits consist of the following: for each undersupply energy imbalance in excess of the deviation band in an hour, the amount by which the Transmission Provider's revenues for such imbalance pursuant to Section 4.1 exceed the incremental cost incurred to supply that imbalance.

The imbalance penalty revenues calculated for each hour shall be credited based on the ratio of the transmission revenues from each Network Transmission Customer or Point-to-Point Transmission Customer that did not experience an energy imbalance in excess of the deviation band in an hour to the sum of the transmission revenues from all Transmission Customers that did not experience energy imbalances in the hour. A Transmission Customer that experiences an energy imbalance in excess of the first tier deviation band in an hour shall not receive a credit for that hour.

~~4.4~~4.2.2 The Transmission Provider shall disburse accumulated penalty revenues, plus interest calculated in accord with 18 C.F.R. § 35.19a, when the accumulated amount of penalty revenues collected under Section 4.1 of this ~~s~~Schedule and ~~Section 9.1 of~~ Schedule ~~9~~13 reaches $100,000. However, effective as of April 1, 2009 and every April 1st thereafter, if a distribution has not been made within the previous twelve-month period, a distribution will be made no later than April 1 of that calendar year.

4.3. DEC Zone

In the DEC Zone, for purposes of this Schedule 4 and Schedule 13, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched for any purpose, e.g., to supply the Transmission Provider's Native Load Customers, correct imbalances, or make off-system sales. The cost calculation is based on individual generating unit heat rates, start up costs (including any commitment and redispatch costs), variable cost of fuel, variable cost of emissions (SO2 and NOx), variable operation and maintenance costs, purchased and interchange power costs and taxes, as applicable. The following is a detailed description of the elements of incremental/decremental cost and the process used to derive the value:

- PACE modeling - PACE (Post Analysis Cost Evaluation) software is used to calculate the variable cost of generation for each hour of each day. PACE is integrated with the Transmission Provider's energy accounting database and utilizes logic that identifies each generating unit that was online for the hour and then ranks the generating units from highest to lowest cost based on the variable operating cost of the individual generating units. The software logic also has the ability to bifurcate hourly data and takes into account individual heat rates of the generating units. Variable costs include start up, fuel, emissions and operations and maintenance costs which are further described below.
- Unit heat rate - is a measure of the thermal efficiency of a generating unit and is typically calculated by dividing the total Btu content of fuel burned (or heat released from a nuclear reactor) by the resulting net Kwh generated. The optimal heat rate, which is the theoretical most efficient level of operation, is achieved after a start up period and is generally represented by a curve linear mathematical progression.
- Variable cost of fuel - is based on actual inventory and/or acquisition cost of fuel used to produce energy. Fuel cost is measured at each plant location and includes the cost of the fuel commodity (e.g. coal, gas) plus delivery costs such as rail or pipeline transportation cost. Fuel cost related to coal fired generation is calculated

by taking the average value of coal inventory at the beginning of the month adding the value of shipments received less the average value of the inventory at the end of the month (beginning inventory plus shipments minus ending inventory = fuel cost of energy produced). With respect to natural gas fired generation, the Transmission Provider does not currently maintain an inventory of natural gas. The variable cost of natural gas fuel is the actual cost of the gas fuel consumed during the month. The variable cost of nuclear fuel is based on the weighted average inventory cost of nuclear fuel including enrichment costs and other ancillary costs necessary to bring the fuel to a usable state. Total fuel cost for each plant is divided by the actual MWh's produced by the plant. The resulting cost per MWh is input to PACE which is then used to calculate variable fuel cost for each generating unit based on the number of MWh's that the generating unit produced during the month.

- Variable cost of emissions - is based on the weighted average inventory cost of SO2 and NOx emissions allowances consumed in the production of the energy. Actual emissions, generally measured in tons emitted, are measured at each plant utilizing gauges and other devices installed in plant components where emissions occur (e.g. smokestacks). Variable cost is based on the weighted average cost of SO2 and NOx emissions and is calculated as follows: total inventory cost of emissions / tons of allowances in inventory = average cost per ton (SO2 and NOx are calculated separately). The average cost per ton is then multiplied by the tons emitted by each plant for the month. Total emissions cost for the plant is then divided by the MWh's produced by the plant for the month to derive a cost per MWh. PACE then calculates variable emissions cost for each generating unit that was online during the month.

- Variable operations and maintenance cost (VO&M) - operations and maintenance costs are categorized into three principal types - fixed, variable and start up. Both the variable and start up components are utilized in the calculation of incremental / decremental cost. Variable and start up operations and maintenance costs include but are not limited to:
  - The cost of materials and labor expended to maintain the Transmission Provider's generation assets (boilers, turbines, reactors, etc) in accordance with manufacturer specifications, warranties and recommendations. In addition, for equipment that has no associated manufacturer specifications, warranties or recommendations, maintenance is performed based on management judgment.
  - Ash disposal costs.
  - Reagent costs.

  Variable and start up operations and maintenance costs are generally expended on the following assets and activities:
  - Electric generation assets such as boilers, electric plant, turbines, reactors and hydro plant facilities.
  - Coal handling and other inventory type equipment that is integrated with generation assets.
  - Environmental equipment utilized in the production of electricity.
- Purchased power - the Transmission Provider purchases power from third parties in normal course of business. Purchases are typically initiated based on economic

merit as compared to the current cost of generation. The cost of purchased power, including the transmission service required for delivery to the Transmission Provider's service territory border, is included in incremental/decremental cost calculations. Purchased power is measured on a cost per MWh and is incorporated into the PACE model algorithm. Purchased power cost is weighted equally with the variable operating costs of the Transmission Provider's generation assets.

For DEC, the variable costs described above, including purchased power, are input to the PACE model each month. PACE then ("stacks") the generation that was online each hour from highest to lowest cost. The incremental and decremental cost is calculated each hour as follows:

(Total variable cost of generation for the hour - total variable cost of generation - 10MW for the hour)/10MW = incremental decremental cost per MWh.

4.3.1 Credits for Energy and Generation Imbalance Penalty Revenues:

On a monthly basis, the Transmission Provider will credit revenues that it receives in excess of the costs it incurs to accommodate energy and generation imbalances ("Penalty revenues") to customers who have not experienced energy or generation imbalances outside the deviation band.

(i) The credits for energy imbalance shall be calculated and allocated as set forth below:

The penalty revenues for which the Transmission Provider provides credits will be calculated every hour. For any underdelivery imbalance in excess of the deviation band in an hour, the penalty revenue shall be the amount by which the Transmission Provider's revenues for such imbalance exceed the incremental cost incurred to supply that imbalance. The energy imbalance penalty revenues shall be credited to Point-to-Point Transmission Customers and to Network Customers that are load serving entities (excluding full requirements customers of the Transmission Provider and Native Load Customers) that did not experience an energy imbalance outside the deviation band during the billing hour (collectively, "Non-Offending Energy Imbalance Customers"). The imbalance penalty revenues shall be credited based on a ratio of the sum of a Non-Offending Customer's schedules (as recorded at the Point of Delivery) for the hour divided by the sum of all schedules (as recorded at the Point of Delivery) of all Non-Offending Customers' during the hour.

(ii) The credits for generation imbalance shall be calculated and allocated as set forth below:

The penalty revenues for which the Transmission Provider provides credits will be calculated every hour. For any underdelivery imbalance in excess of the deviation band in an hour, the penalty revenue shall be the amount by which the Transmission Provider's revenues for such imbalance exceed the incremental cost incurred to supply that imbalance.

The generation imbalance penalty revenues shall be credited to (i) Point-to-Point Transmission Customers, (ii) Network Customers that are load serving entities (excluding full requirements customers of the Transmission Provider and Native Load Customers) that did not experience a generation imbalance outside the deviation band during the billing hour, and (iii) customers taking Generation Imbalance Service under Schedule 13 that did not experience a generation imbalance outside the deviation band for the hour (collectively, "Non-Offending Generation Imbalance Customers"). The imbalance penalty revenues shall be credited based on a ratio of the sum of a Non-Offending Customer's schedules (as recorded at the Point of Delivery) for the hour divided by the sum of all schedules (as recorded at the Point of Delivery) of all Non-Offending Customers' during the hour.

(iii) The Transmission Provider shall disburse accumulated imbalance penalty revenues in the form of credits on a monthly basis.

SCHEDULE 5

~~**Operating Reserve - Spinning Reserve Service**~~

OPERATING RESERVE - SPINNING RESERVE SERVICE

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. If the Transmission Customer elects to provide this service itself or by contracting with a third party, the Transmission Customer or the third party provider shall meet the applicable NERC, FRCC, SERC, and VACAR requirements for this service.

Charges:

The charge for Spinning Reserve Service shall be based on the Zone in which the load is located. The applicable zonal charges are set out below.

A. CP&L Zone

A.5.1 Spinning Reserve Capacity

A Transmission Customer purchasing Spinning Reserve Service will be required to purchase an amount of Customer Spinning Reserve Capacity (CSR) equal to 1.77 percent of the Transmission Customer's reserved capacity for Point-to-Point Transmission Service or ~~Network Contract Demand Transmission Service or~~ 1.77 percent of the Network Integration Transmission Customer's maximum hourly network load responsibility during each service period (e.g., Daily Period or Weekly Period) for service periods less than one month or 1.77 percent of the Network Integration Transmission Customer's hourly network load coincident with the hour of the Transmission Provider's monthly transmission peak for Network Integration Transmission Customers subscribing to service periods of a month or longer. The billing determinants for this service shall be reduced by any portion of the 1.77 percent purchase obligation that a Transmission Customer obtains from third parties or supplies itself.

A.5.2 Spinning Reserve Capacity Rate

The maximum rates for Spinning Reserve Capacity Rate (SRR) shall be as follows for the service periods indicated:

a. For service provided for an Annual or Monthly Period, the rate shall not exceed $3,960 per MW-month.

b. For service provided for Weekly Period, the rate shall not exceed $913.85 per MW-week.

c. For service provided for a Daily Period, the rate shall not exceed $182.77 per MW-day for ~~On~~on-~~P~~peak ~~D~~days and $130.55 per MW-day for ~~O~~off-~~P~~peak ~~D~~days.

A.5.3 Spinning Reserve Capacity Charges

The Transmission Customer's Spinning Reserve Capacity Charge for the Monthly Period is as follows:

SRC = CSR X SRR

Where:

SRC is the Transmission Customer's Spinning Reserve Capacity Charge.
CSR is the amount of Spinning Reserve Capacity purchased by the Transmission Customer during the service period as determined in Section A.5.1.
SRR is the applicable Spinning Reserve Capacity Rate.

A.5.3.1 The sum of the charges for Weekly Period service supplied during a Monthly Period shall not exceed the charges for the same amount of capacity purchased for a Monthly Period.

A.5.3.2 The sum of the charges for Daily Period service supplied during a Weekly Period shall not exceed the charges for the same amount of capacity purchased for a Weekly Period.

A.5.4 Availability and Application of Spinning Reserve Capacity

Spinning reserve capacity shall be available in an amount up to 50% of the Transmission Customer's capacity reservation for Point-to-Point service or ~~Network Contract Demand Transmission Service or~~ up to the Network Integration Customer's peak network load for network service for the first ten (10) minutes immediately following an unplanned outage of a Transmission Customer's generation resource. If Spinning Reserve Service is purchased from multiple suppliers or self-supplied by the Transmission Customer, the amount of spinning reserve service capacity that CP&L must keep on line shall be reduced by the amount of spinning reserve service purchased elsewhere or self-supplied. A Transmission Customer must purchase or provide both Spinning Reserve and Supplemental Reserve Service in order to cover 100% of the Transmission Customer's load for the first ten (10) minutes following a system contingency.

A.5.5 Notification Requirements

In the event of a system contingency that causes the interruption or curtailment of deliveries from a Transmission Customer's owned or purchased generating resource (i) that is electrically within CP&L's control area and/or (ii) for which the Transmission Customer has made arrangements with CP&L to provide Spinning Reserve Service, the Transmission Customer must use best efforts to notify CP&L within 10 minutes of the occurrence of the contingency or as soon as practicable thereafter.

A.5.6 Energy Accounting for Spinning Reserve Service

In the event of a system contingency for which CP&L provides Spinning Reserve Service hereunder, any energy provided to the Transmission Customer without prior scheduling shall be treated as follows:

A.5.6.1 If the Transmission Customer has provided the required notification, contained in Section A.5.5, following the contingency,

A.5.6.1.1 Spinning reserve energy provided to the Transmission Customer during the initial 10-minute period will be offset or credited against Energy Imbalances so that the net Energy Imbalance accounts such that Energy Imbalance for that 10-minute period is zero, and

A.5.6.1.2 Spinning reserve energy provided to the Transmission Customer for periods longer than the initial 10-minute period will be handled as Energy Imbalance Service under Schedule 4 of this Tariff unless other arrangements exist between CP&L and the Transmission Customer for backup service, or

A.5.6.2 If the Transmission Customer has not provided the required notification, contained in Section A.5.5, following a contingency, all energy provided by

CP&L will be handled as Energy Imbalance Service under Schedule 4 of this Tariff.

B. FPC Zone

B.5.1 Charges

The maximum charges for Operating Reserve - Spinning Reserve Service are no greater than:

B.5.1.1 $6,122/MW month for service in an Annual Period or a Monthly Period.

B.5.1.2 $1,412.67/MW week for service in a Weekly Period.

B.5.1.3 $282.53/MW day for service in a Daily Period for ~~On~~on-~~P~~peak ~~D~~days and $201.26/MW day for ~~O~~off-~~P~~peak ~~D~~days; provided that the maximum charge in any Weekly Period shall be no greater than the product of the maximum service reserved in any Daily Period in that Weekly Period and the maximum charge for Weekly Period service.

B.5.1.4 $17.66/MW hour for service in an Hourly Period for ~~On~~on-~~P~~peak ~~H~~hours and $8.39/MW hour for ~~O~~off-~~P~~peak ~~H~~hours. The maximum charge in any Daily Period shall not exceed the product of the maximum service reserved in any Hourly Period in that Daily Period and the maximum charge for Daily Period service; and the maximum charge in any Weekly Period shall not exceed the product of the maximum service reserved in any Hourly Period in that Weekly Period and the maximum charge for Weekly Period service.

B.5.2 A Transmission Customer purchasing Spinning Reserve Service will be required to purchase an amount of service equal to 0.7 percent of the Transmission Customer's Reserved Capacity for Network Contract Demand Transmission Service or Point-To-Point

Transmission Service or 0.7 percent of the Transmission Customer's Network Load for the applicable month for Network Integration Transmission Service. The billing determinants for this service shall be reduced by any portion of the 0.7 percent purchase obligation that a Transmission Customer obtains from third parties or supplies itself. If the FRCC assigns a different requirement directly to the customer, then the above percentage would not apply. If the Transmission Customer requires energy from the capacity reserved pursuant to this Schedule, such energy shall be treated as Inadvertent Energy, consistent with the Florida Specific Procedures entitled "Reserve Capacity" and "Inadvertent Accounting" in the FRCC Handbook.

B.5.3 Self-Supply of Service

A Transmission Customer that is located in FPC's Control Area shall purchase Spinning Reserve Service from the Transmission Provider unless it provides comparable service from its own generators or purchases from a third party Spinning Reserve Service that is available from on-line generation located within peninsular Florida in an amount equal to the reserve capability required by the FRCC Operating Committee, as modified from time to time.

C. DEC Zone

C.5.1 The Point to Point Transmission Service Customer shall compensate the Transmission Provider each month for Operating Reserve - Spinning Reserve Service provided by the Transmission Provider at the sum of the applicable charges set forth below:

C.5.1.1 For Monthly Service, $.0815/kW of Reserved Capacity per month.

C.5.1.2 For Weekly Service, $.019/kW of Reserved Capacity per week.

C.5.1.3 For Daily On Peak Service, $.004/kW of Reserved Capacity per on peak days.

C.5.1.4 For Daily Off Peak Service, $.0027/kW of Reserved Capacity per off peak days.

C.5.1.5 For Hourly On Peak Service, $.00025/kW of Reserved Capacity per on peak hours.

C.5.1.6 For Hourly Off Peak Service, $.00011/kW of Reserved Capacity per off peak hours.

The annual revenue requirements for purposes of Operating Reserve - Spinning Reserve Service for Network Integration Transmission Service shall be $16,361,940. The Network Integration Transmission Service Customer shall compensate the Transmission Provider each month for Operating Reserve - Spinning Reserve Service provided by the Transmission Provider at the sum of the Transmission Customer's monthly Load Ratio Share calculated on a rolling twelve month basis multiplied by one-twelfth of the annual revenue requirements of $16,361,940.

If, in the event of a system contingency, energy must be provided beyond a 10-minute period due to system or unit rampdown, such energy will be priced in accordance with the penalty provisions of Schedule 4, Energy Imbalance Service, unless other arrangements with the Transmission Provider are in place for backup service.

SCHEDULE 6

~~**Operating Reserve - Supplemental Reserve Service**~~

OPERATING RESERVE
SUPPLEMENTAL RESERVE SERVICE

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. If the Transmission Customer elects to provide this service itself or by contracting with a third party, the Transmission Customer or the third party provider shall meet the applicable NERC, FRCC, SERC, and VACAR requirements for this service.

Charges:

The charge for Supplemental Reserve Service shall be based on the Zone in which the load is located. The applicable zonal charges are set out below.

A. CP&L Zone

A.6.1 Supplemental Reserve Capacity

A Transmission Customer purchasing Supplemental Reserve Service will be required to purchase an amount of Customer Supplemental Reserve Capacity (CSUR) equal to 1.77 percent of the Transmission Customer's reserved capacity for Point-to-Point Transmission Service or ~~Network Contract Demand Transmission Service or~~ 1.77 percent of the Network Integration Transmission Customer's maximum hourly network load responsibility during each service period (e.g., Daily Period or Weekly Period) for service periods less than one month or 1.77 percent of the Network Integration Transmission Customer's hourly network load coincident with the hour of the Transmission Provider's monthly transmission peak for Network Integration Transmission Customers subscribing to service periods of a month or longer. The billing determinants for this service shall be reduced by any portion of the 1.77 percent purchase obligation that a Transmission Customer obtains from third parties or supplies itself.

A.6.2 Supplemental Reserve Capacity Rate

The maximum rates for Supplemental Reserve Capacity Rate (SURR) shall be as follows for the service periods indicated:

A.6.2.1 For service provided for an Annual or Monthly Period, the rate shall not exceed $2,830 per MW-month.

A.6.2.2 For service provided for a Weekly Period, the rate shall not exceed $653.08 per MW-week.

A.6.2.3 For service provided for a Daily Period, the rate shall not exceed $130.62 per MW-day for ~~On~~on-~~P~~peak ~~D~~days and $93.30 per MW-day for ~~O~~off-~~P~~peak ~~D~~days.

A.6.3 Supplemental Reserve Capacity Charges

The Transmission Customer's Supplemental Reserve Capacity Charge for the Monthly

Period is as follows:

SURC = CSUR X SURR

Where: SURC is the Transmission Customer's Supplemental Reserve Capacity Charge.

CSUR is the amount of Supplemental Reserve Capacity purchased by the Transmission Customer during the service period as determined in Section A.6.1.

SURR is the applicable Supplemental Reserve Capacity Rate.

A.6.3.1 The sum of the charges for Weekly Period service supplied during a Monthly Period shall not exceed the charges for the same amount of capacity purchased for a Monthly Period.

A.6.3.2 The sum of the charges for Daily Period service supplied during a Weekly Period shall not exceed the charges for the same amount of capacity purchased for a Weekly Period.

A.6.4 Availability and Application of Supplemental Reserve Capacity

Supplemental reserve capacity shall be available in an amount up to 50% of the Transmission Customer's capacity reservation for Point-to-Point service or ~~Network Contract Demand Transmission Service or~~ up to the Network Integration Customer's peak network load for network service for the first ten (10) minutes immediately following an unplanned outage of a Transmission Customer's generation resource. If Supplemental Reserve Service is purchased from multiple suppliers or self-supplied by the Transmission Customer, the amount of supplemental reserve capacity provided by CP&L shall be reduced by the amount of supplemental reserve capacity purchased elsewhere or self-supplied. A Transmission Customer must purchase or provide both Spinning Reserve and Supplemental Reserve Service in order to cover 100% of the Transmission Customer's load for the first ten (10) minutes following a system contingency.

A.6.5 Notification Requirements

In the event of a system contingency that causes the interruption or curtailment of deliveries from a Transmission Customer's owned or purchased generating resource (i) that is electrically within CP&L's control area and/or (ii) for which the Transmission Customer has made arrangements with CP&L to provide Supplemental Reserve Service, the Transmission Customer must use best efforts to notify CP&L within 10 minutes of the occurrence of the contingency or as soon as practicable thereafter.

A.6.6 Energy Accounting for Supplemental Reserve Service

In the event of a system contingency for which CP&L provides Supplemental Reserve Service hereunder, any energy provided to the Transmission Customer without prior scheduling shall be treated as follows:

A.6.6.1 If the Transmission Customer has provided the required notification, contained in Section A.6.5, following the contingency,

A.6.6.1.1 Supplemental reserve energy provided to the Transmission Customer during the initial 10-minute period will be offset or credited against Energy Imbalances so that the net Energy Imbalance for that 10-minute period is zero, and

A.6.6.1.2 Supplemental reserve energy provided to the Transmission Customer for periods longer than the initial 10-minute period will be handled as Energy Imbalance Service under Schedule 4 of this

Tariff unless other arrangements exist between CP&L and the Transmission Customer for backup service, or

A.6.6.2 If the Transmission Customer has not provided the required notification, contained in Section A.6.5, following a contingency, all energy provided by CP&L will be handled as Energy Imbalance Service under Schedule 4 of this Tariff.

B. FPC Zone

B.6.1 Charges:

The maximum charges for Operating Reserve - Supplemental Reserve Service are no greater than:

B.6.1.1 $2,081/MW month for service in an Annual Period or a Monthly Period.

B.6.1.2 $480.13/MW week for service in a Weekly Period.

B.6.1.3 $96.03/MW day for service in a Daily Period for ~~On~~on-~~P~~peak ~~D~~days and $68.40/MW day for ~~O~~off-~~P~~peak ~~D~~days; provided that the maximum charge in any Weekly Period shall be no greater than the product of the maximum service reserved in any Daily Period in that Weekly Period and the maximum charge for Weekly Period service.

B.6.1.4 $6.00/MW hour for service in an Hourly Period for ~~On~~on-~~P~~peak ~~H~~hours and $2.85/MW hour for ~~O~~off-~~P~~peak ~~H~~hours. The maximum charge in any Daily Period shall not exceed the product of the maximum service reserved in any Hourly Period in that Daily Period and the maximum charge for Daily Period service; and the maximum charge in any Weekly Period shall not exceed the product of the maximum service reserved in any Hourly Period in that Weekly

Period and the maximum charge for Weekly Period service.

B.6.2 A Transmission Customer purchasing Supplemental Reserve Service will be required to purchase an amount of service equal to 2.0 percent of the Transmission Customer's Reserved Capacity for Network Contract Demand Transmission Service or Point-To-Point Transmission Service or 2.0 percent of the Transmission Customer's Network Load for the applicable month for Network Integration Transmission Service. The billing determinants for this service shall be reduced by any portion of the 2.0 percent purchase obligation that a Transmission Customer obtains from third parties or supplies itself. If the FRCC assigns a different requirement directly to the customer, then the above percentage would not apply. If the Transmission Customer requires energy from the capacity reserved pursuant to this Schedule, such energy shall be treated as Inadvertent Energy, consistent with the Florida Specific Procedures entitled "Reserved Capacity" and "Inadvertent Accounting" in the FRCC Handbook.

B.6.3 Self-Supply of Service

A Transmission Customer that is located within the Transmission Provider's Control Area shall purchase Supplemental Reserve Service from the Transmission Provider unless it provides comparable service from its own generation or purchases from a third party Supplemental Reserve Service that is available from on-line, unloaded generation, quick-start generation or interruptible load equal to the reserve capability required by the FRCC Operating Committee, as modified from time to time.

C. DEC Zone

C.6.1 The Point to Point Transmission Service Customer shall compensate the Transmission Provider each month for Operating Reserve - Supplemental Reserve Service provided by the Transmission Provider at the sum of the applicable charges set forth below:

C.6.1.1 For Monthly Service, \$.0815/kW of Reserved Capacity per month.

C.6.1.2 For Weekly Service, \$.019/kW of Reserved Capacity per week.

C.6.1.3 For Daily On Peak Service, \$.004/kW of Reserved Capacity per on peak days.

C.6.1.4 For Daily Off Peak Service, \$.0027/kW of Reserved Capacity per off peak days.

C.6.1.5 For Hourly On Peak Service, \$.00025/kW of Reserved Capacity per on peak hours.

C.6.1.6 For Hourly Off Peak Service, \$.00011/kW of Reserved Capacity per off peak hours.

C.6.2 The annual revenue requirements for purposes of Operating Reserve - Supplemental Reserve Service for Network Integration Transmission Service shall be \$16,361,940. The Network Integration Transmission Service Customer shall compensate the Transmission Provider each month for Operating Reserve - Supplemental Reserve Service provided by the Transmission Provider at the sum of the Transmission Customer's monthly Load Ratio Share calculated on a rolling twelve month basis multiplied by one-twelfth of the annual revenue requirements of \$16,361,940.

C.6.3 If, in the event of a system contingency, energy must be provided beyond a 10-minute period due to system or unit rampdown, such energy will be priced in accordance with the penalty provisions of Schedule 4, Energy Imbalance Service, unless other arrangements with the Transmission Provider are in place for backup service.

SCHEDULE 7

~~**Long Term Firm and Short Term Firm Point To Point Transmission Service**~~

LONG-TERM FIRM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges for a zone set forth below:

Charges:

The charges for Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service shall be based on the Zone in which the energy being transmitted is consumed or, if the energy is transmitted to an interface with another transmission provider, the Zone in which transmission service is last provided by the Transmission Provider, except in the case of energy being transmitted to serve Network Load under Part III of this Tariff in which case the applicable charge will be under Section 34 of the Tariff.

The applicable zonal charges are set out below.

A. CP&L Zone

A.7.1 Annual, Monthly, Weekly and Daily Periods: The rates for the Annual Period, the Monthly Period, the Daily Period for ~~On~~on-~~P~~peak ~~D~~days and the Daily Period for ~~O~~off-~~P~~peak ~~D~~days are derived from the Formula Rate, which is set forth in OATT Attachment H.1. The Formula Rate is implemented in accordance with the OATT Attachment H.2 Formula Rate Implementation Protocols.

A.7.2 Daily Period: The total demand charge in any Weekly Period, pursuant to a reservation for Daily Period delivery, shall not exceed the Weekly Period rate times the highest amount in kilowatts of Reserved Capacity in any Daily Period during such Weekly Period.

A.7.3 Annual Update: The rates for Schedule 7 shall be updated annually on June 1st of each year in accordance with the OATT Attachment H.2 Formula Rate Implementation Protocols.

A.7.4 Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discount transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

A.7.5 Unauthorized Use: In the event that the Transmission Customer's use of the Transmission System during any hour of that day exceeds the amount of the Transmission Customer's Reserved Capacity, the Transmission Customer shall pay the Transmission Provider a penalty charge based on a rate equal to 200% of the applicable rate for Firm Point-to-Point Transmission Service. For unreserved use within a single day, the penalty charge shall be based on the daily rate. For unreserved use in two or more days within a calendar week, the penalty charge shall be based on the weekly rate. For multiple instances of unreserved use in more than one calendar week in a calendar month, the penalty charge shall be based on the monthly rate. Losses delivered to the CP&L Zone by the Transmission Customer will not be included in the Transmission Customer's usage for determination of the charge set out herein.

A.7.6 Credits for Unreserved Use Penalty Revenues: The Transmission Provider shall credit revenues that are collected for unreserved use to all non-offending Transmission Customers (including Affiliated Transmission Customers) and to the Transmission Provider on behalf of its own customers (Native Load Customers). The credits shall be calculated and allocated as set forth below.

The penalty revenues collected pursuant to Section A.7.6 of this schedule shall be credited based on the ratio of the transmission revenues collected from each Network Transmission Customer or Point-to-Point Transmission Customer that did not experience unreserved use in an hour to the sum of the transmission revenues collected from all Transmission Customers that did not experience unreserved use in the hour. A Transmission Customer that experiences unreserved use in an hour shall not receive a credit for that hour.

The Transmission Provider shall disburse accumulated penalty revenues, plus interest calculated in accord with 18 C.F.R. § 35.19a, when the accumulated amount of penalty revenues collected under Section A.7.6 of this schedule and Section A.8.6 of Schedule 8 reaches $50,000. However, if a distribution has not been made within the previous 12 month period, a distribution will be made no later than April 1 of that calendar year.

A.7.7 Additional Charges: The Transmission Customer will compensate CP&L for any facility additions or redispatch costs in accordance with Sections 13.5, 27 and 45.2 of the Tariff. ~~Redispatch costs will be computed in accordance with the methodology outlined in Attachment J.~~

A.7.8 Losses: For purposes of billing, the Reserved Capacity to be applied under Sections A.7.1 through A.7.4 of this schedule shall not include losses purchased or provided by the Transmission Customer.

A.7.9 Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by ~~s~~Section 23.1 of the Tariff.

B. FPC Zone

B.7.1 Monthly, Weekly and Daily Periods: The rates for the Monthly Period, the Weekly Period and the Daily Period for ~~On~~on-~~P~~peak ~~D~~days and the Daily Period for ~~O~~off-~~P~~peak ~~D~~days are derived from the Formula Rate, which is set forth in OATT Schedules ~~10.2~~10-A.2 and ~~10.3.~~10-A.3. The resulting rates are posted on the Transmission Provider's OASIS. The Formula Rate is implemented in accordance with the OATT Schedule ~~10.1~~10-A.1 Formula Rate Implementation Protocols.

B.7.2 Daily Period: The total demand charge in any Weekly Period, pursuant to a reservation for Daily Period delivery, shall not exceed the Weekly Period rate times the highest amount in kilowatts of Reserved Capacity in any Daily Period during such Weekly Period.

NOTE: All quantities used in calculating the Transmission Customer's Reserved Capacity shall be established at the transmission system input level, *i.e.*, shall include the transmission capacity amount associated with any losses.

B.7.3 Annual Update: The rates for Schedule 7 shall be updated annually on June 1st of each year in accordance with the OATT Schedule ~~10.1~~10-A.1 Formula Rate Implementation Protocols.

B.7.4 Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discount transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

B.7.5 Unauthorized Use: In the event a Transmission Customer's use of the Transmission System during any hour of that day exceeds the amount of the Transmission Customer's Reserved Capacity, the Transmission Customer shall pay the Transmission Provider a penalty charge based on a rate equal to 200% of the applicable rate for Firm Point-to-Point Transmission Service. For unreserved use within a single day, the penalty charge shall be based on the daily rate. For unreserved use in two or more days within a calendar week, the penalty charge shall be based on the weekly rate. For multiple instances of unreserved use in more than one calendar week in a calendar month, the penalty charge shall be based on the monthly rate.

B.7.6 Credits for Unreserved Use Penalty Revenues: The Transmission Provider shall credit revenues that are collected for unreserved use to all non-offending Transmission Customers (including Affiliated Transmission Customers) and to the Transmission Provider on behalf of its own customers (Native Load Customers). The credits shall be calculated and allocated as set forth below.

The penalty revenues collected pursuant to Section B.7.5 of this schedule shall be credited based on the ratio of the transmission revenues collected from each Network Transmission Customer or Point-to-Point Transmission Customer that did not experience unreserved use in an hour to the sum of the transmission revenues collected from all Transmission Customers that did not experience unreserved use in the hour. A Transmission Customer that experiences unreserved use in an hour shall not receive a credit for that hour.

The Transmission Provider shall disburse accumulated penalty revenues, plus interest calculated in accord with 18 C.F.R. § 35.19a, when the accumulated amount of penalty revenues collected under Section B.7.5 of this schedule and Section B.8.6 of Schedule 8 reaches $50,000. However, if a distribution has not been made within the previous 12 month period, a distribution will be made no later than April 1 of that calendar year.

B.7.7 **Regulatory Assessment:** The portion of the charge by FERC pursuant to 18 C.F.R. § 382.201 related to service under this Tariff. The Regulatory Assessment shall be allocated to the Transmission Customer on an annual basis in the year following the year in which transmission service is rendered, based on the megawatt-hours of service provided to the Transmission Customer or based upon such other method as these fees are assessed by FERC.

B.7.8 **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by ~~s~~Section 23.1 of the Tariff.

C. DEC Zone

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

C.7.1 Yearly delivery: one-twelfth of the Annual Demand Charge determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per year.

C.7.2 Monthly delivery: the Monthly Demand Charge determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per month.

C.7.3 Weekly delivery: the Weekly Demand Charge determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per week.

C.7.4 Daily on-peak delivery: the Daily On-Peak Demand Charge determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per on-peak days.

C.7.5 Daily off-peak delivery: the Daily Off-Peak Demand Charge determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per off-peak days. The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

C.7.6 Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s)of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

C.7.7 **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section 23.1 of the Tariff.

C.7.8 In the event that the Transmission Customer exceeds its firm Reserved Capacity at any Point of Receipt and/or Point of Delivery (or any combination of such points, together with any Secondary Points of Receipt and Delivery pursuant to Section 22.1), the Transmission Customer shall pay two times the charge under Schedule 7 for the maximum amount during the relevant time period that the Transmission Customer exceeds its firm Reserved Capacity at any Point of Receipt and/or Point of Delivery. The unreserved use penalty for one hour of unreserved use within the same day will be based on the rate for daily firm point-to-point service. If the Transmission Customer incurs more than one assessment for a given duration the penalty period will be increased to the next longest duration. Pursuant to Section 3, Ancillary Services charges will be based on the amount of transmission service used but not reserved for each hour of unreserved use.

Exhibit A to Schedule 7

Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service Rates in the DEC Zone

1. The Annual Demand Charge for a calendar year is equal to A / B, where:

    - A = the Transmission Revenue Requirement for the calendar year as determined in Schedule 10-B, Exhibit B.

    - B = the average of the Transmission Provider's twelve Monthly Transmission System Peaks (expressed in kilowatts) for the calendar year as defined in Section 34.3 of the Tariff.

2. The Monthly Demand Charge is equal to the Annual Demand Charge divided by twelve (12).

3. The Weekly Demand Charge is equal to the Annual Demand Charge divided by fifty-two (52).

4. The Daily On-Peak Demand Charge is equal to the Weekly Demand Charge divided by five (5).

5. The Daily Off-Peak Demand Charge is equal to the Weekly Demand Charge divided by seven (7).

SCHEDULE 8

~~Non-Firm Point-To-Point Transmission Service~~

NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges ~~for a zone~~ set forth below:

Charges:

The charge for Non-Firm Point-To-Point Transmission Service shall be based on the Zone in which the energy being transmitted is consumed or, if the energy is transmitted to an interface with another transmission provider, the Zone in which transmission service is last provided by the Transmission Provider. The applicable zonal charges are set out below.

A. CP&L Zone

A.8.1 Monthly, Weekly, Daily and Hourly Periods: The rates for the Annual Period, the Monthly Period, the Daily Period for ~~On~~on-~~P~~peak ~~D~~days and the Daily Period for ~~O~~off-~~P~~peak ~~D~~days, the Hourly Period for ~~On~~on-~~P~~peak ~~H~~hours and the Hourly Period for ~~O~~off-~~P~~peak ~~H~~hours are derived from the Formula Rate, which is set forth in OATT Attachment H.1 and Attachment H.2 Formula Rate Implementation Protocols.

A.8.2 Daily Period: The total demand charge in any Weekly Period, pursuant to a reservation for Daily Period delivery, shall not exceed the Weekly rate times the highest amount in kilowatts of Reserved Capacity in any Daily Period during such Weekly Period.

A.8.3 Hourly Period: The total demand charge in any Daily Period, pursuant to a reservation for Hourly Period delivery, shall not exceed the Daily Period rate times the highest amount in kilowatts of Reserved Capacity in any Hourly Period during such Daily Period. In addition, the total demand charge in any Weekly Period, pursuant to a reservation for Hourly Period or Daily Period delivery, shall not exceed the Weekly Period rate times the highest amount in kilowatts of Reserved Capacity in any Hourly Period during such Weekly Period.

A.8.4 **Annual Update:** The rates for Schedule 8 shall be updated annually on June 1st of each year in accordance with the OATT Attachment H.2 Formula Rate Implementation Protocols.

A.8.5 **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount, agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discount transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

A.8.6 **Unauthorized Use:** In the event that the Transmission Customer's use of the Transmission System during any hour of that day exceeds the amount of the Transmission Customer's Reserved Capacity, the Transmission Customer shall pay the Transmission Provider a penalty charge based on a rate equal to 200% of the applicable rate for Firm Point-to-Point Transmission Service. For unreserved use within a single day, the penalty charge shall be based on the daily Firm Point-to-Point Transmission Service rate. For unreserved use in two or more days within a calendar week, the penalty charge shall be based on the weekly Firm Point-to-Point Transmission Service rate. For multiple instances of unreserved use in more than one calendar week in a calendar month, the penalty charge shall be based on the monthly Firm Point-to-Point Transmission Service rate.

Losses delivered to the CP&L Zone by the Transmission Customer will not be included in the Transmission Customer's usage for determination of the charge set out herein.

A.8.7 Credits for Unreserved Use Penalty Revenues: The Transmission Provider shall credit revenues that are collected for unreserved use to all non-offending Transmission Customers (including Affiliated Transmission Customers) and to the Transmission Provider on behalf of its own customers (Native Load Customers). The credits shall be calculated and allocated as set forth below.

The penalty revenues collected pursuant to Section A.8.6 of this schedule shall be credited based on the ratio of the transmission revenues collected from each Network Transmission Customer or Point-to-Point Transmission Customer that did not experience unreserved use in an hour to the sum of the transmission revenues collected from all Transmission Customers that did not experience unreserved use in the hour. A Transmission Customer that experiences unreserved use in an hour shall not receive a credit for that hour.

The Transmission Provider shall disburse accumulated penalty revenues, plus interest calculated in accord with 18 C.F.R. § 35.19a, when the accumulated amount of penalty revenues collected under Section A.8.6 of this schedule and Section A.7.6 of Schedule 7 reaches $50,000. However, if a distribution has not been made within the previous 12 month period, a distribution will be made no later than April 1 of that calendar year.

A.8.8 Additional Charges: The Transmission Customer will compensate CP&L for any facility additions or redispatch costs in accordance with Sections 13.5, 27 and 45.2 of the Tariff. ~~Redispatch costs will be computed in accordance with the methodology outlined in Attachment J.~~

A.8.9 Losses: For purposes of billing, the Reserved Capacity to be applied under Sections A.8.1 through A.8.4 of this schedule shall not include losses purchased or provided by the Transmission Customer.

A.8.10 Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by ~~s~~Section 23.1 of the Tariff.

B. FPC Zone

B.8.1 Monthly, Weekly, Daily and Hourly Periods: The rates for the Monthly Period, the Weekly Period, the Daily Period for ~~On~~on-~~P~~peak ~~D~~days, the Daily Period for ~~O~~off-~~P~~peak ~~D~~days, the Hourly Period for ~~On~~on-~~P~~peak ~~H~~hours and the Hourly Period for ~~O~~off-~~P~~peak ~~H~~hours are derived from the Formula Rate, which is set forth in OATT Schedules ~~10.2~~10-A.2 and ~~10.3.~~10-A.3. The resulting rates are posted on the Transmission Provider's OASIS. The Formula Rate is implemented in accordance with the OATT Schedule ~~10.1~~10-A.1 Formula Rate Implementation Protocols.

B.8.2 Daily Period: The total demand charge in any Weekly Period, pursuant to a reservation for Daily Period delivery, shall not exceed the Weekly Period rate times the highest amount in kilowatts of Reserved Capacity in any Daily Period during such Weekly Period.

B.8.3 Hourly Period: The total demand charge in any Daily Period, pursuant to a reservation for

Hourly Period delivery, shall not exceed the Daily Period rate times the highest amount in kilowatts of Reserved Capacity in any Hourly Period during such Daily Period. In addition, the total demand charge in any Weekly Period, pursuant to a reservation for Hourly Period or Daily Period delivery, shall not exceed the Weekly Period rate times the highest amount in kilowatts of Reserved Capacity in any Hourly Period during such Weekly Period.

NOTE: All quantities used in calculating the Transmission Customer's Reserved Capacity shall be established at the transmission system input level, *i.e.*, shall include the transmission capacity amount associated with any losses.

B.8.4 Annual Update: The rates for Schedule 8 shall be updated annually on June 1st of each year in accordance with the OATT Schedule ~~10.1~~10-A.1 Formula Rate Implementation Protocols.

B.8.5 Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount~~,~~ agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

B.8.6 Unauthorized Use: In the event a Transmission Customer's use of the Transmission

System exceeds the amount of the Transmission Customer's Reserved Capacity, the Transmission Customer shall pay the Transmission Provider a penalty charge based on a rate equal to 200% of the applicable rate for Firm Point-to-Point Transmission Service. For unreserved use within a single day, the penalty charge shall be based on the daily Firm Point-to-Point Transmission Service rate. For unreserved use in two or more days within a calendar week, the penalty charge shall be based on the weekly Firm Point-to-Point Transmission Service rate. For multiple instances of unreserved use in more than one calendar week in a calendar month, the penalty charge shall be based on the monthly Firm Point-to-Point Transmission Service rate.

B.8.7 Credits for Unreserved Use Penalty Revenues: The Transmission Provider shall credit revenues that are collected for unreserved use to all non-offending Transmission Customers (including Affiliated Transmission Customers) and to the Transmission Provider on behalf of its own customers (Native Load Customers). The credits shall be calculated and allocated as set forth below.

The penalty revenues collected pursuant to Section B.8.6 of this schedule shall be credited based on the ratio of the transmission revenues collected from each Network Transmission Customer or Point-to-Point Transmission Customer that did not experience unreserved use in an hour to the sum of the transmission revenues collected from all Transmission Customers that did not experience unreserved use in the hour. A Transmission Customer that experiences unreserved use in an hour shall not receive a credit for that hour.

The Transmission Provider shall disburse accumulated penalty revenues, plus interest calculated in accord with 18 C.F.R. § 35.19a, when the accumulated amount of penalty revenues collected under Section B.8.6 of this schedule and Section B.7.5 of Schedule 7 reaches $50,000. However, if a distribution has not been made within the previous 12 month period, a distribution will be made no later than April 1 of that calendar year.

B.8.8 Regulatory Assessment: The Transmission Customer shall pay a portion of the charge by FERC pursuant to 18 C.F.R. § 382.201 related to service under this Tariff. The Regulatory Assessment shall be allocated to the Transmission Customer on an annual basis in the year following the year in which transmission service is rendered, based on the megawatt-hours of service provided to the Transmission Customer or based upon such other method as these fees are assessed by FERC.

B.8.9 Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by ~~s~~Section 23.1 of the Tariff.

C. DEC Zone

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

C.8.1 Monthly delivery: the Monthly Demand Charge determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per month.

C.8.2 Weekly delivery: the Weekly Demand Charge determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per week.

C.8.3 Daily on-peak delivery: the Daily On-Peak Demand Charge determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per on-peak days.

C.8.4 Daily off-peak delivery: the Daily Off-Peak Demand Charge determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per off-peak days. The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

C.8.5 Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved. For service during On-Peak hours, in no event shall the charge exceed the Hourly On-Peak Demand charge determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per on peak hours. For service during Off-Peak hours, in no event shall the charge exceed the Hourly Off-Peak Demand charge determined pursuant to Exhibit A to this Schedule, multiplied by the amount of Reserved Capacity per off-peak hours. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

C.8.6 Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

C.8.7 Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section 23.1 of the Tariff.

C.8.8 Billing Credits for Interrupted Non-Firm Point-to-Point Service: Billing relief is provided to Non-Firm Point-to-Point Transmission Customers whose reservations are displaced by higher priority reservations. In these instances, the Transmission Customer's bill (including required Ancillary Services) shall be determined by the percentage of the reservation that was served.

C.8.9 In the event that the Transmission Customer exceeds its non-firm Reserved Capacity at any Point of Receipt and/or Point of Delivery, the Transmission Customer shall pay, for the contract period (i.e., monthly, weekly, daily, or hourly) for which the Transmission Customer reserves capacity, the charge under Schedule 8 (subject to applicable caps) for the maximum amount that the Transmission Customer exceeds its non-firm Reserved Capacity at any Point of Receipt and/or Point of Delivery. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

Exhibit A to Schedule 8

Non-Firm Point-to-Point Transmission Service Rates for the DEC Zone

1. The Monthly Demand Charge during any month of a calendar year is equal to A / B, where:

   - A = the Annual Transmission Revenue Requirement for the calendar year as determined in Schedule 10-B, Exhibit B.

   - B = the total of the Transmission Provider's twelve Monthly Transmission System Peaks (expressed in kilowatts) for the calendar year as defined in Section 34.3 of the Tariff.

2. The Weekly Demand Charge is equal to the Monthly Demand Charge multiplied by twelve (12) and divided by fifty-two (52).

3. The Daily On-Peak Demand Charge is equal to the Weekly Demand Charge divided by five (5).

4. The Daily Off-Peak Demand Charge is equal to the Weekly Demand Charge divided by seven (7).

5. The Hourly On-Peak Demand Charge is equal to the Daily On-Peak Demand Charge divided by sixteen (16).

6. The Hourly Off-Peak Demand Charge is equal to the Daily Off-Peak Demand Charge divided by twenty-four (24).

SCHEDULE 9

~~Generator Imbalance Service~~ [Comparison of FPC former Schedule 9 is provided at Schedule 13]

LOSS COMPENSATION SERVICE

[DEC Zone]

Capacity and energy losses occur when a Transmission Provider delivers electricity across its transmission facilities for a Transmission Customer. A Transmission Customer may elect to (1)supply the capacity and/or energy necessary to compensate the Transmission Provider for such losses, (2) receive an amount of electricity at delivery points that is reduced by the amount of losses incurred by the Transmission Provider, or (3) with the concurrence of the Transmission Provider, have the Transmission Provider supply the capacity and/or energy necessary to compensate for such losses.

The loss factor used to determine the amount of losses associated with the use of facilities other than distribution facilities shall be three (3) percent. The Transmission Provider will determine such losses by dividing the sum of hourly energy scheduled to be delivered to the Transmission Customer's Points of Delivery by 0.97 less the amount scheduled to be delivered. Determination of losses to be supplied by the Transmission Customer by coincident schedules will be done on a daily basis for each schedule. However, in no event shall such determination result in the Transmission Provider being undercompensated after any hour. If the Transmission Provider and Transmission Customer agree to have the Transmission Provider compensate for losses under option 3 above, the Transmission Customer shall be charged for Loss Compensation Service at a rate not to exceed 100 percent of the Transmission Provider's incremental cost to produce energy after serving all other obligations (including economy and opportunity transactions) and a Generation Capacity Loss Adder of $.006 per kWh.

SCHEDULE 10-A

~~Network Integration Transmission Service~~

NETWORK INTEGRATION TRANSMISSION SERVICE

[FPC Zone ~~Only~~]

The Transmission Customer shall compensate the Transmission Provider each month for its Network Load for the applicable month as follows:

10.1 Monthly delivery: The charge for Network Integration Transmission Service is derived from the Formula Rate, which is set forth in OATT Schedules ~~10.2~~10-A.2 and ~~10.3.~~10-A.3. The resulting rate is posted on the Transmission Provider's OASIS. The Formula Rate is implemented in accordance with the OATT Schedule ~~10.1~~10-A.1 Formula Rate Implementation Protocols. The charge for Network Integration Transmission Service shall be updated annually on June 1st of each year in accordance with the OATT Schedule ~~10.1~~10-A.1 Formula Rate Implementation Protocols.

NOTE: All quantities used in calculating the Network Integration Customer's Network Load shall be adjusted to the transmission system input level, *i.e.*, shall include the transmission capacity amount associated with any applicable losses.

10.2 Regulatory Assessment: The Transmission Customer shall pay a portion of the charge by FERC pursuant to 18 C.F.R. § 382.201 related to service under this Tariff. The Regulatory Assessment shall be allocated to the Transmission Customer on an annual basis in the year following the year in which transmission service is rendered, based on the megawatt-hours of service provided to the Transmission Customer or based upon such other method as these fees are assessed by FERC.

SCHEDULE ~~10.1~~10-A.1
Formula Rate Implementation Protocols

[FPC Zone]

Section 1 The Annual Update Process

a. The unit charges for transmission service under Schedules 7, 8, 10-A and 12 of the Tariff shall be determined and updated annually through the application of the Formula Rate comprising Schedules ~~10.2~~10-A.2 and ~~10.3~~10-A.3 of the Tariff in the following manner:

(i) Subject to Sections 1.a(iii) and 4 below, the initial unit charges for transmission service shall apply to service provided during the period January 1, 2008 through May 31, 2008 (inclusive), which unit charges reflect the Transmission Provider's actual costs and demands for calendar year 2006. The unit charges for transmission service shall be changed annually beginning June 1, 2008, in accordance with the process set forth in the following Sections 1.a(ii) and 1.a(iii).

(ii) Beginning in 2008 and continuing each year thereafter, on or before May 15 of each year, PEF shall calculate unit charges for transmission service reflecting its actual costs and demands for the prior calendar year. Such calculation ("Annual Update") shall be made in accordance with the Formula Rate comprising Schedules ~~10.2~~10-A.2 and ~~10.3.~~10-A.3. The transmission unit charges determined in the Annual Update shall be placed into effect beginning on June 1 of the year in which the Annual Update is performed (i.e., beginning June 1 of the year following the calendar year upon which the Annual Update is based). Such transmission unit charges shall continue in effect through May 31 of the following year, unless changed as provided in Section 4. (To put this in a calendar-year context, for any given calendar year, the amounts billed for transmission service provided during the period of January 1 through May 31 of that calendar year shall be computed using the unit charges determined in the Annual Update performed in the prior calendar (reflecting actual costs and demands for the second preceding calendar year), except as such unit charges may be changed as provided in Section 4, and such billed amounts for transmission service provided during the period of June 1 through December 31 of that calendar year shall be computed using the unit charges determined in the Annual Update performed in that calendar year (reflecting actual costs and demands for the preceding calendar year), except as such unit charges may be changed as provided in Section 4.)

(iii) At the time of, and in conjunction with, each Annual Update (beginning in calendar year 2009), amounts billed to all Transmission Customers for Network Integration Transmission Service, Network Contract Demand Service, and Long-Term Firm Point-to-Point Transmission Service (i.e., but not for Short-Term Firm Point-to-Point Transmission Service or Non-Firm Point-to-Point Transmission Service) provided during the calendar year upon which the Annual Update is based (i.e., the calendar year preceding the year in which the Annual Update is performed) shall be "trued up" as follows: (1) The monthly amounts billed to each Transmission Customer for Network Integration Transmission Service, Network Contract Demand

Service, and Long-Term Point-to-Point Transmission Service for service provided during all twelve months of such prior calendar year (i.e., the year being trued-up) shall be recomputed using the transmission unit charges reflecting actual costs and demands, as determined in the Annual Update. (2) The resulting recomputed monthly amounts to each such Transmission Customer shall be compared to the amounts that had been included in that Transmission Customer's monthly billings for service during that calendar year (which shall have been determined using the transmission unit charges that shall have been in effect pursuant to Sections 1.a(i) and 1.a(ii) above). (3) The difference between the recomputed amounts and the previously billed amounts, together with interest determined in accordance with 18 C.F.R. § 35.19, shall, as appropriate, be refunded to the Transmission Customer within 30 days, or charged to the Transmission Customer on the next monthly bill to that Transmission Customer, following the Publication Date (as hereinafter defined) of the Annual Update.

(iv) In the event that the Formula Rate shall have changed one or more times during a calendar year, the Annual True-Up for that year shall have multiple parts, one part for each period in which a different Formula Rate was in effect. Each part shall accomplish the true-up of charges for the portion of the year during which the respective Formula Rate was in effect. For purposes of such true-up, (1) the annual revenue requirements for the entire year shall be determined as if the respective Formula Rate was in effect for the entire year, (2) the resulting per-unit rates shall be determined from those revenue requirements and billing determinants for the entire year in accordance with the respective Formula Rate, and (3) the resulting unit prices shall be applied to Transmission Customers' billing determinants for the same portion of the year during which the respective Formula Rate was in effect in order to determine the trued-up charges for that time period (i.e., what the charges reflecting actual costs should have been for such time period). Each set of trued-up charges shall be compared to the actual monthly charges for respective Customers during the corresponding time periods to determine refunds or additional charges, along with appropriate interest determined in accordance with the Formula Rate.

b. Promptly after preparing each Annual Update, but in no event later than May 15 of the year in which the Annual Update is performed (except as provided in Section 1.c below), the Transmission Provider shall:

(i) post the results of such Annual Update on Transmission Provider's Internet website via link to the Transmission Services page or a similar successor page in both a Portable Document Format and fully-functioning Excel file; and

(ii) file the results of such Annual Update with the Federal Energy Regulatory Commission ("FERC" or "Commission") as an informational filing ("Informational Filing"). Consistent with FERC procedures concerning informational filings, the Informational Filing will not be noticed for filing and FERC need not issue an acceptance or approval of the Informational Filing for the rates to go into effect. If the Commission issues a Notice in response to the Informational Filings, the Parties shall advise the Commission of the challenge process in the Formula Rate Implementation Protocols and shall seek an abeyance of the Commission proceeding to permit that challenge process to proceed.

c. If the May 15 deadline set forth above for making the Annual Update posting/filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall be due on the next business day.

d. Subject to Section 4.e, the date that is the later of (i) the last of the events listed in Sections 1.b. and 1.c., above, or (ii) the date of the actual posting of the Transmission Provider's Annual Update shall be the "Publication Date" of that Annual Update.

e. The Formula Rate is premised upon the following predicates:

(i) the FERC's Uniform System of Accounts ("USoA"),

(ii) FERC Form No. 1[1] reporting requirements as applicable,

(iii) FERC's orders establishing generally applicable transmission ratemaking policies (including, but not limited to, FERC's policy that all charges billed under formula rates are subject to prudence challenges and after-the-fact refund)[2] and

(iv) the Transmission Provider's accounting policies, practices and procedures

1 If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

2 Challenges to prudency of costs shall apply the then-existing criteria and evidentiary burdens established in FERC policy. Nothing in these Protocols alters or changes those criteria and evidentiary burdens. See also Section 3.c. of the Protocols.

that are consistent with Section 1.e.i. above, as each of such predicates ("Fundamental Predicates") exists as of the date of the initial filing by the Transmission Provider of the Formula Rate, subject to such Fundamental Predicate(s) being changed in accordance with the procedures provided for in this Schedule ~~10.1~~10-A.1 or by the FERC.

f. The Annual Update and the Transmission Provider's associated Informational Filing:

(i) shall be based upon the data properly recordable and recorded in (a) the Transmission Provider's FERC Form No. 1 report (to the extent the Formula Rate specifies Form 1 data as the input source) and (b) the books and records of the Transmission Provider maintained in accordance with the USoA (as defined above) and other FERC accounting policies (to the extent the Formula Rate specifies such data as the input source);

(ii) shall, as and to the extent specified in the Formula Rate, provide supporting documentation for data not otherwise available in the FERC Form No. 1 that are used in the Formula Rate;

(iii) shall provide notice of material changes in the Transmission Provider's accounting policies, practices and procedures from those in effect for the calendar year upon which the immediately preceding Annual Update was based ("Material Accounting Changes");[3]

(iv) shall be subject to review and challenge, in accordance with the procedures set forth in this Schedule ~~10.1,~~10-A.1, to verify that the input data is

[3] Such notice may also incorporate by reference applicable disclosure statements filed with the Securities and Exchange Commission ("SEC").

properly recordable and recorded, and otherwise consistent with Section 1(f)(i) and the Fundamental Predicates, and that the Formula Rate has been applied according to its terms and the procedures in this Schedule ~~10.1~~10-A.1 (including terms and procedures related to challenges concerning consistency with and changes in Fundamental Predicates); and

(v) shall not seek to amend the Formula Rate, and except as provided in Section 1.h, below, shall not be subject to Preliminary or Formal Challenge seeking to amend the Formula Rate (i.e., all amendments to the Formula Rate (including return on common equity and other items specified in Section 1.i., below) shall require, as applicable, a Federal Power Act Section 205 or Section 206 filing).

g. All change(s) to the Fundamental Predicates set forth in Section 1.e., above, (other than through Ministerial Filings pursuant to Section 5 hereof that update FERC Form 1 or USoA references and do not make substantive changes to the Formula Rate), subsequent to the date specified in Section 1.e., shall warrant a re-assessment of all of the elements of the Formula Rate that are affected by the change or changes in one or more Fundamental Predicates to ensure that the Formula Rate operates together to produce a just, reasonable and not unduly discriminatory or preferential Formula Rate. Changes to the Fundamental Predicates that require a change to the Formula Rate will be perfected by the Transmission Provider through a filing under Federal Power Act Section 205.

h. Any interested party seeking changes in the application of the Formula Rate (including a change to the Formula Rate itself) due to a change in one or more of the Fundamental Predicates shall raise the matter with the Transmission Provider. If such changes to the application of the Formula Rate for the current Annual Update are not resolved within one hundred and twenty (120) days of the Publication Date, any interested party shall have the right to challenge such application of the Formula Rate, in the manner otherwise provided pursuant to this Schedule ~~10.1,~~10-A.1, due to the change(s) in such Fundamental Predicates. The final resolution of any such challenge(s), including interest calculated in accordance with 18 C.F.R. § 35.19a, (a) shall be effective on June 1 of the year in which the Annual Update was performed; and, (b) shall be applied to the true up for the calendar year upon which the Annual Update is based.

i. The values for (i) rate of return on common equity; (ii) depreciation rates, (iii) "Post-Employment Benefits Other Than Pensions" pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions ("PBOP"), and (iv) annual storm damage accruals and the maximum storm damage reserve level are deemed an integral part of the Formula Rate, not subject to change except pursuant to an FPA Section 205 or 206 filing.

j. All data provided pursuant to and in accordance with the procedures set forth in this Schedule ~~10.1~~10-A.1 may be used in any challenge to the Annual Update of the Formula Rate.

k. It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1

by the application of clearly identified and supported information. Where the reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

Section 2 Annual Review Procedures

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a. Each year the Transmission Provider shall organize a meeting or conference call among interested parties ("Customer Meeting") during which the Transmission Provider shall present details about its Annual Update. The Customer Meeting shall also provide interested parties the chance to seek information and clarifications from the Transmission Provider about the Annual Update. The Customer Meeting shall take place no later than thirty (30) days after the Publication Date, at a date and time posted on the Transmission Provider's internet website on or before the Publication Date but in no event less than fifteen (15) days before such Customer Meeting.

b. In addition to the informal means of requesting and sharing information about the Annual Update set forth in Section 2(a), any interested party shall have up to one hundred twenty (120) days after the Publication Date (unless such period is extended with the written consent of the Transmission Provider) to review the calculations ("Review Period") and to notify the Transmission Provider in writing of any specific challenges, including challenges related to changes in Fundamental

Predicates, to the application of the Formula Rate ("Preliminary Challenge"). Notice of such Preliminary Challenges shall be promptly posted (at the same location as the Annual Update) by the Transmission Provider.

c. Interested parties shall have up to ninety (90) days after each annual Publication Date (unless such period is extended with the written consent of the Transmission Provider) to serve reasonable information requests on the Transmission Provider. Such information requests shall be limited to what is necessary to determine that the input data is properly recordable and recorded, consistent with Section 1(f)(i) and the Fundamental Predicates and with the application of the Formula Rate and the procedures in this Schedule ~~10.1,~~10-A.1, and to determine the extent and effect(s) of changes in the Fundamental Predicates. In addition, except as to allocation of intangible plant and prepayments, such information requests shall not solicit information that solely relates to inputs that are stated values or cost allocation methods that have been determined by any final order by the FERC pursuant to FPA Sections 205, 206, or 306 with respect to the Transmission Provider (including an order approving a settlement), except that such information requests shall be permitted if they seek to determine if there have been material changed circumstances and to confirm consistency with the applicable order (and associated settlement, if any).

d. The Transmission Provider shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests. Such data responses shall be served on all customers identifying themselves to the Transmission Provider as interested.

e. Subject to the limitations in Section 3(e), the failure to make a Preliminary Challenge to an Annual Update shall not act as a bar with respect to making a Formal Challenge as to that Annual Update nor shall failure to make a Preliminary Challenge or Formal Challenge as to any Annual Update act as a bar to a Preliminary Challenge or Formal Challenge related to any subsequent Annual Update.

Section 3 Resolution of Challenges

a. If the Transmission Provider and an interested party who has raised a Preliminary Challenge have not resolved a Preliminary Challenge to an Annual Update, the interested party shall have the right to make a Formal Challenge with the FERC, pursuant to 18 C.F.R. § 385.206, and Sections 206 and/or 306 of the Federal Power Act, at any time after thirty (30) days after the Review Period. All other interested parties shall have the right to make a Formal Challenge at any time as provided in these protocols. Any Formal Challenge shall be served on the Transmission Provider by electronic service on the date of such filing. However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 2 if the FERC already has initiated a proceeding to consider the Annual Update.

b. Any response by the Transmission Provider to a Formal Challenge must be submitted to the FERC within thirty (30) days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) by electronic service on the date of such filing.

c. In any proceeding initiated by the FERC concerning the Annual Update or in response to a Formal Challenge, the Transmission Provider shall bear the burden of proving that it has reasonably applied the terms of the Formula Rate (including, but not limited to, consistency with the Fundamental Predicates), and the applicable procedures in this Schedule ~~10.1,~~10-A.1, for that year's Annual Update; provided, however, that challenges to the prudency of costs shall apply then-existing criteria and evidentiary burdens established in FERC policy applicable to prudence challenges in a Section 205 context.

d. In any proceeding initiated under Federal Power Act Section 206, interested parties seeking to change the Formula Rate shall bear the burden of proof. Notwithstanding any refund effective date that may be assigned to such Section 206 proceeding, any change to the Formula Rate or input data that results from such Section 206 proceeding, which was filed during the period when an Annual Update was not yet final pursuant to Section 3(e), shall be implemented using the same procedures included in Section 4.

e. Subject to judicial review of FERC orders, each Annual Update shall become final and no longer subject to challenge pursuant to these Formula Rate Implementation Protocols or by any other means by the FERC or any other entity, including the Transmission Provider, on the later to occur of (i) passage of twelve (12) months from the Publication Date (or extended period, if applicable) if no such challenge has been made or the FERC has not initiated a proceeding to consider the Annual Update, or (ii) a final FERC order issued in response to a Formal Challenge or a proceeding initiated by the FERC to consider the Annual Update; provided, however, that if a mistake or error is made in an Annual Update in a given year

("Year X Update") that becomes apparent due to Preliminary or Formal Challenges made to (or FERC-initiated proceeding regarding) the first or second subsequent Annual Update, refunds with interest, in accordance with 18 C.F.R. § 35.19a, will be due relating to the Year X Update.

f. Except as provided in Section 1.h, no interested party may seek to amend the Formula Rate by means of a Preliminary or Formal Challenge. Except as specifically provided herein, nothing herein shall be deemed to limit in any way (i) the right of the Transmission Provider to file unilaterally, pursuant to FPA Section 205 and the regulations thereunder, proposed changes to the Formula Rate or any of its inputs that are stated values, or (ii) the right of any interested party to request such changes pursuant to FPA Section 206 and the regulations thereunder.

g. It is recognized that resolution of Formal Challenges concerning changes in Fundamental Predicates shall necessitate adjustments to the Formula Rate input data for the applicable Annual Update or changes to the Formula Rate that are affected by the change or changes in one or more Fundamental Predicates to ensure that all elements of the Formula Rate that are affected by the change in the Fundamental Predicate(s) operate together to produce a just, reasonable and not unduly discriminatory or preferential Formula Rate.

Section 4 Changes to Annual Informational Filings

At any time following the Publication Date of an Annual Update, such Annual Update and the unit charges resulting therefrom may be changed (i) to correct errors therein, (ii) to reflect the resolution of Preliminary Challenges or Formal Challenges by settlement, or (iii) to reflect actions by FERC, and the resulting changed Annual Update shall be referred to as a "Revised Annual Update." As to each such Revised Annual Update:

a. If the unit charges resulting from the Annual Update performed pursuant to Section 1.a (i) or (ii) hereof or previous revisions thereto (referred to as the "Then-Current Annual Update") are still in effect, the unit charges shall be changed to reflect the Revised Annual Update beginning with the next monthly billing cycle for which it is practical to do so.

b. For Network Integration Transmission Service, Network Contract Demand Service, and Long-Term Firm Point-to-Point Transmission Service:

   (i) If, at the time of the revision to an Annual Update pursuant to Section 4.a above, the amounts billed using the unit charges from such Then-Current Annual Update have not been trued-up to reflect actual costs and demands pursuant to Section 1.a(iii) hereof, such billed amounts shall be recomputed using the unit charges resulting from the Revised Annual Update, and appropriate refunds provided, or additional amounts billed, as soon as practical following the change.

   (ii) If, at the time of the Revised Annual Update, the amounts billed using the unit charges from the Then-Current Annual Update shall have been trued up to reflect actual costs and demands pursuant to Section 1.a(iii) hereof, such true-up shall be recomputed on the basis of each Revised Annual Update, and appropriate additional refunds made or amounts billed as soon as practical following the subject change.

c. For Short-Term Firm Point-to-Point Transmission Service and Non-Firm Point-to-Point Transmission Service:

(i) All billed amounts made to Transmission Customers that shall have been computed using the unit charges resulting from the Then-Current Annual Update at issue (*i.e.*, charges for service provided during the period beginning June 1 immediately following the original preparation of the Annual Update at issue) shall be recomputed using the unit charges resulting from the Revised Annual Update, and appropriate refunds provided, or additional amounts billed, as soon as practical following the change.

d. All refunds and additional charges to Transmission Customers resulting from changes to an Annual Update (including, but not limited to, changes resulting from a Section 206 filing pursuant to Section 3.d) shall include interest determined in accordance with 18 C.F.R. § 35.19a and (a) shall be effective on June 1 of the year in which the Annual Update was performed; and, (b) shall be applied to the true up for the calendar year upon which the Annual Update is based. All such refunds and additional charges shall also appropriately take into account refunds and additional charges, if any, that shall have previously been made in connection with prior changes, if any, to the subject Annual Update.

e. If the subject change set forth in Section 4.d. above is not the direct result of an order by FERC, the Transmission Provider shall promptly file with FERC the Revised Annual Update in connection with the subject Annual Update and shall promptly update its internet posting associated therewith. The aspects of the Revised Annual Update that are different from the subject Annual Update and any elements affecting those changes or that are affected by such changes will obtain a new Publication Date, which shall be the date of filing of the Revised Annual Update at FERC.

Section 5 Update of Formula Rate for FERC Form No. 1 and USoA References

At such time as the Transmission Provider finds appropriate, it may make a filing with FERC under Section 205 that updates the FERC Form No. 1 and USoA references in its Formula Rate to reflect any FERC-mandated changes in the format for the FERC Form No. 1 or USoA that do not affect the rates for Transmission Service derived from the Annual Update (the "Ministerial Filing"), which proceeding may not be used to raise issues unrelated to the proposed changes ("Limited 205 Proceeding"). Alternatively, the Form 1 and USoA reference changes that could be made in a Ministerial Filing may be filed as part of a filing under Federal Power Act Section 205 to otherwise amend the Formula Rate, in which proceeding any issues related to the Formula Rate may be raised ("Normal 205 Proceeding"). Prior to or between any such Limited 205 Proceeding or Normal 205 Proceeding, to the extent changes in the FERC-mandated format of the Form 1 or USoA cause the then current Form 1 or USoA to depart from the Form 1 or USoA referenced in the Formula Rate but does not affect the rates for Transmission Service derived from the Annual Update, the Transmission Provider's Annual Update shall include a reconciliation so that interested parties can confirm that the Formula Rate is being applied consistent with the as-filed Formula Rate.

Schedule ~~10.2~~10-A.2 Formula Rate Template
[FPC Zone]

Exhibit PEF - 2
Page 1 of 6
Year Ending 12/31/yyyy

PROGRESS ENERGY FLORIDA, INC.
OATT Transmission Non-Levelized Rate Formula Template Using Form-1 Data

Summary of Rates

Line		Reference	Total	Allocator		OATT Transmission
1	Gross PEF Revenue Requirement	Page 3, Line 35				0
	Revenue Credits:					
2	Acct 454 - Transmission Related	Exhibit PEF - 3	0	D/A	1.00000	0
3	Acct 456 - NF + STF Service (x/ Ancillaries)	Exhibit PEF - 3	0	D/A	1.00000	0
4	Total Revenue Credits		0			0
5	Interest Disbursed with Network Prepayment Refunds					0
6	Revenue Req't - Customer Owned Facilities					0
7	Net Revenue Requirements (Line 1 - Line 4 + Line 5 + Line 6)					0
8	Divisor - Sum of Monthly MW Transmission System Peaks (Excludes STF)	p.5, line 15 Total				0
9	Trans. Rev Req't Rate $/MW-Mon.	Line 7 / Line 8				0
10	Storm Reserve Adder	Page 5, Line 9				140
11	Total Firm Monthly Trans. $/MW-Month	Line 9 + Line 10				0
12	Annual Firm Trans $/MW-year	Line 11 * 12				0
13	Weekly Firm/Non-Firm P-t-P Rate $/MW-Week	Line 12 / 52				0.00
	Daily Firm/Non-Firm P-t-P Rates ($/MW):					
14	On-Peak Days	Line 13 / 5				0.00
15	Off-Peak Days	Line 13 / 7				0.00
	Non-Firm Hourly P-t-P Rates ($/MWh):					
16	On-Peak Hours	Line 14 / 16				0.00
17	Off-Peak Hours	Line 15 / 24				0.00

PROGRESS ENERGY FLORIDA, INC.
OATT Transmission Non-Levelized Rate Formula Template Using Form-1 Data

Development of Rate Base and Capital Structure

Line	RATE BASE:	Reference	Beginning Balance	Ending Balance	B/E Average	Allocator		OATT Transmission
	Gross Plant in Service (Note A):							
1	Production Plant	205.46.b&g	0	0	0	N/A		
2	Transmission Plant (Note V)	207.58.b&g	0	0	0			
2A	Less Direct Assign Radials	PEF - 7, ll 1&5	0	0	0			
2B	Trans. Plant w/o Direct Assign Radials				0	TP	0.00000	0
3	Distribution Plant	207.75.b&g	0	0	0	N/A		
4	General Plant	207.99.b&g	0	0	0	OATT LABOR	0.00000	0
5	Intangible Plant	205.5.b&g	0	0	0	OATT LABOR	0.00000	0
6	**Total Gross Plant**				0	GP =	0.00000	0
	Accumulated Depreciation:							
7	Production Depr. Reserve	219.20 thru 24.c	0	0	0	N/A		
8	Transmission Depr. Reserve (Note V)	219.25.c	0	0	0			
8A	Less Direct Assign Radials	PEF - 7, ll 7&10	0	0	0			
8B	Trans. Reserve w/o Direct Assign Radials				0	TP	0.00000	0
9	Distribution Depr. Reserve	219.26.c	0	0	0	N/A		
10	General Depr. Reserve	219.28.c	0	0	0	OATT LABOR	0.00000	0
11	Intangible Amort. Reserve	200.21.c	0	0	0	OATT LABOR	0.00000	0
12	**Total Accumulated Depr.**				0			0
	Net Plant in Service							
13	Net Production Plant	Line 1 - Line 7			0			
14	Net Transmission Plant	Line 2 - Line 8			0			0
15	Net Distribution Plant	Line 3 - Line 9			0			
16	Net General Plant	Line 4 - Line 10			0			0
17	Net Intangible Plant	Line 5 - Line 11			0			0
18	**Total Net Plant**				0	NP =	0.00000	0
	Adjustments to Rate Base - Deferred Taxes							
19	ADIT - 190	234.8.b&c	0	0	0	Exhibit PEF - 5		0
20	ADIT - 281 (Negative)	273.8.b&k	0	0	0	Exhibit PEF - 5		0
21	ADIT - 282 (Negative)	275.2.b&k	0	0	0	Exhibit PEF - 5		0
22	ADIT - 283 (Negative)	277.9.b&k	0	0	0	Exhibit PEF - 5		0
23	**Total Deferred Tax Adjustments**				0			0
24	**Unfunded Reserves**	Note U	0	0	0	Exhibit PEF-5A		0
25	**Net 182.1 (+) / Storm Reserve (-) - Wholesale Transmission (Note B)**	230a.5.f	0	0	0	p. 5, l. 16	0.00000	0
26	**Plant Held for Future Use**	214.47.d	0	0	0	Note C		0
27	**Transmission Related CWIP - Identified Projects (Note V):**		0	-	0		0.50000	0
	Rate Base Adjustments - Network Upgrade Prepayments (Note O):							
28	Outstanding Balance - Network Prepayments (Note T)		0	0	0	D/A	(1.00000)	0
29	Interest Accrued/Capitalized on Network Prepayments		0	0	0	D/A	1.00000	0
30	**Total Network Upgrade Prepayment Adjustments**							0
	Working Capital:							
31	Cash Working Capital (1/8 O&M)	Page 3, line 17						0
32	M&S - Transmission	227.8.b&c	0	0	0	TExp	0.00000	0
33	M&S - Stores Expense	227.16.b&c	0	0	0	OATT LABOR	0.00000	0
34	Prepayments (Note L)	111.57.c&d	0	0	0	GP	0.00000	0
35	**Total Working Capital**							0
36	**Rate Base (Sum of Lines 18, 23 thru 27, 30, and 35)**							0
	AVERAGE CAPITALIZATION:							
37	Long Term Debt	112.24.c&d	0	0	0			
38	Less Loss on Reacquired Debt	111.81.c&d	0	0	0			
39	Plus Gain on Reacquired Debt	113.61.c&d	0	0	0			
40	Less Securitization Bonds	Note I	0	0	0			
41	Net Long Term Debt				0			
42	Preferred Stock	112.3.c&d	0	0	0			
	Common Stock Development:							
43	Proprietary Capital	112.16.c&d	0	0	0			
44	Less Preferred Stock	112.3.c&d	0	0	0			
45	Less Account 216.1	112.12.c&d	0	0	0			
46	Common Stock				0			
47	Total Capitalization (Sum of Lines 41, 42, and 46)				0			

PROGRESS ENERGY FLORIDA, INC.
OATT Transmission Non-Levelized Rate Formula Template Using Form-1 Data

Development of Revenue Requirements

Line	EXPENSES:	Reference	Total	Allocator		OATT Transmission
	O&M Expense					
1	TOTAL Transmission Expenses	321.112.b	0			
2	Less Account 561	321.84-92.b	0			
3	Less Account 565	321.96.b	0			
4	Net Transmission O&M	Note H	0	TExp	0.00000	0
5	Total Admin & General Expenses (Note S)	323.197.b	0			
6	Less (924) Property Insurance	323.185.b	0			
7	Less (928) Regulatory Commission Expenses	323.189.b	0			
8	Less (930.1) General Advertising Expenses	323.191.b	0			
9	Less Industry Dues and R&D Expense	335.1-3.b	0			
10	Net Labor Related A&G		0	OATT LABOR	0.00000	0
11	(924) Property Insurance	323.185.b	0			
12	Less system storm reserve funding		0			
13	Net Allocated Property Insurance		0	GP	0.00000	0
14	Trans. Related Regulatory Expense	Note D		D/A	1.00000	0
15	Trans. Related Advertising Exp.	Note D		D/A	1.00000	0
16	Adj. to Imputed Whlse PBOP Exp. - System	Page 6	0	OATT LABOR	0.00000	0
17	**Total O&M (Sum of Lines 4, 10, and 13 thru 16)**					**0**
	Depreciation Expense					
18	Transmission Depr. Expense (Note V)	336.7.f	0			
18A	Less Direct Assign Radial Depr Exp	PEF-7, line 8	0			
18B	Trans Depr. w/o Direct Assign Radials		0	TP	0.00000	0
19	General Depr. Expense	336.10.f	0	OATT LABOR	0.00000	0
20	Intangible Amortization (Note E)	336.1.f	0	OATT LABOR	0.00000	0
21	**Total Depreciation**		0			**0**
	Taxes Other Than Income (Note F)					
22	Labor Related	263.i	0	OATT LABOR	0.00000	0
23	Property Related	263.i	0	GP	0.00000	0
24	**Total Other Taxes**		0			**0**
	Return:					
25	Rate Base (Page 2, Line 36) * Rate of Return (Page 4, Line 27)					**0**
	Income Taxes:					
26	State of Florida	Note M	0.00%			
27	Federal	Note M	0.00%			
28	Composite T = State + Federal * (1 - State)		0.00%			
29	Tax Rev.Req't Factor = T / (1 -T) * (1 - Wtd.Debt.Cost/R_0)		0.00%			
30	ITC Gross Up Factor = 1 / (1 -T)		0.000			
31	Amortized ITC (Negative)	266.8.f	0			
32	Income Taxes Calculated (Line 25 * Line 29)					0
33	ITC Adjustment (Line 30 * Line 31)		0	NP	0.00000	0
34	**Total Income Taxes**					**0**
35	**TOTAL REVENUE REQUIREMENT (Sum of Lines 17, 21, 24, 25, and 34)**					**0**

PROGRESS ENERGY FLORIDA, INC.
OATT Transmission Non-Levelized Rate Formula Template Using Form-1 Data

Supporting Allocation Factor and Return Calculations

Line		Reference	Total
	B/E Avg. Transmission Plant Included in OATT Rate:		
1	Total Transmission Plant w/o D/A Radials	p 2, line 2B	0
2	Less Gen. Step-up Transformers in 353	Exhibit PEF - 4	0
3	Less Interconnection Facilities (Order 2003)	Exhibit PEF - 4	0
4	Less Energy Control Center	Note G	0
5	Avg.Trans Plant for OATT Rate		0
6	**TP Allocator (Line 5 / Line 1)**	Note H	0.00000
7	Add Back ECC to OATT Plant (Line 4 + Line 5)		0
7A	Add back D/A Radials to Total Trans Plt (line 1 + p2, l 2A)		0
8	**TExp Allocator (Expenses excluding 561 and 565) (Line 7 / Line 7A)**		0.00000
	Labor Allocation Factor		
9	Total Direct Payroll - O&M Labor	354.28.b	0
10	A&G Labor	354.27.b	0
11	Adj. - RCO Labor in A&G Labor		0
12	Adjusted Labor w/o A&G (Line 9 - Line 10 + Line 11)		0
13	Transmission O&M Labor	354.21.b	0
14	**Trans Labor Factor (Line 13 / Line 12)**		0.00000
15	**OATT LABOR Allocator (Line 5 / Line 7A * Line 14)**	Note H	0.00000
	Return and Average Capitalization:		
16	Long Term Interest Expense	117.62 thru 67.c	0
17	Less Interest on Securitization Bonds	Note I	0
18	Net Long Term Interest Expense		0
19	Preferred Dividends (positive)	118.29.c	0
20	Long Term Debt	p.2, line 41	0
21	Preferred Stock	p.2, line 42	0
22	Common Stock	p.2, line 46	0
23	Total Capitalization (sum Lines 20, 21, 22)		0

Line	SUMMARY CAP STRUCTURE	Weight	Cost	Weighted Cost
24	Long term Debt	0.00%	0.00%	0.00%
25	Preferred Stock	0.00%	0.00%	0.00%
26	Common Equity	0.00%	**10.80%**	0.00%
27	**Overall Return: R_0 =**			**0.00%**

PROGRESS ENERGY FLORIDA, INC.
OATT Transmission Non-Levelized Rate Formula Template Using Form-1 Data

Wholesale Storm Reserve Funding and Explanatory Notes

Line		Reference	Total	Allocator		OATT Transmission
1	**Whlse Extraordinary Property Loss**	230a.5.b	0			
2	Trans. Related Pct of Whlse Loss	Note J	0.92011	WEPL-T		
3	**Whlse Trans. Extraordinary Propery Loss**		0	TP2006	0.92366	0
	Components of Storm Amortization/Reserve Funding Adder (2008-2012 Rate Years only - Note N):					
4	Balance 2004 Loss as of Jan 1, 2008	230a.5.f	15,658,702	Fixed	0.84987	13,307,907
	Rebuild Reserve Equivalent to $130MM Retail:					
5	Whlse Portion of $6MM Funding	ER95-469	434,000	Fixed	0.07233	
6	System Total Reserve Req't = 130MM/(1 - Line 5 %)		140,136,543			
7	Whlse Reserve Needed = Line 6 - $130MM		10,136,543	Fixed	0.84987	8,614,774
8	**Whlse Portion of Existing Storm Accrual**	ER95-469	434,000	Fixed	0.84987	368,845
9	**Levelized Storm Reserve Funding Rate $/MW-Month** (PEF - 6, Page 2)					**140**
	Denominator for Wholesale Transmission:					
10	Firm Network Service for Self	400.17.e	0		0.00000	0
11	Firm Network Service for Others (Note K)	400.17.f	0		1.00000	0
12	Long-Term Firm P-t-P Reservations	400.17.g	0		1.00000	0
13	Other Long-Term Firm Service	400.17.h	0		1.00000	0
14	Contract Demand Adjustment		0		1.00000	0
15	Total System Long Term Firm Transmission Load		0			0
16	**Gross-up Factor for OATT Wholesale Reserve - System Basis** (Total Load/Whlse Load * 0.84987)					0.00000

Note A: Excludes Asset Retirement Obligations from plant balances

Note B: Because the Page 2 Rate Base amounts are total system numbers, the wholesale specific loss/reserve balance is grossed up using the relationship between system and wholesale only transmission demands times the percent of the balance applicable to the OATT. See also Notes H and J.

Note C: FERC Form 1 page 214 excluding non-transmission related items

Note D: Analysis of Company books. Regulatory expense excludes charges by FERC pursuant to 18 CFR § 382.201

Note E: Excludes Retail ECCR and Sebring amortizations from Form-1 reported value

Note F: Excludes all income and gross receipts taxes. Labor related other taxes include FICA and unemployment taxes. Property related taxes include county and local property, highway use, and intangible taxes.

Note G: Investment in Transmission Energy Control Center included in Schedule 1 Ancillary Service cost

Note H: The allocator "TP" is the percent of allocated gross transmission plant that is OATT related, i.e., after removal of ECC, interconnections and generator step-up transformer investment.

Note I: To the extent PEF is authorized by the Florida Public Service Commission and issues bonds for distribution facilities to securitize retail recovery of extraordinary property losses, associated principal and interest expense are excluded in capitalization and return basis.

Note J: Functionalized Transmission part 182.1 Extraordinary Property Losses balance only, "WEPL-T." Consistent with the process described in Note H above, the OATT-related amount of the transmission loss is then derived using the TP allocation factor

Note K: Includes Network Integration Service and Network Contract Demand Service

Note L: Beginning balance excludes $0 and ending balance excludes $0 for prepaid pensions from Form-1 A/C 165 balances.

Note M: If income tax rates change during a calendar year, the income tax rates will be pro-rated based on the number of days each income tax rate was in effect.

Note N: Pursuant to the settlement agreement, annual amounts included in line 11 will be adjusted and reversed as necessary to ensure no overfunding of the wholesale reserve; i.e., the year-end reserve balance for OATT rates will not exceed the $8,614,774 shown on line 7

Note O: Payments by PEF to an Affected System Operator pursuant to Orders 2003 or 2006 (including rehearing orders) are not to be included in the formula rate regardless of the accounting.

Note P: Target percentages are fixed for 2008 - 2012 and were derived from projected OATT LTF billing MW-months and the MW-month equivalent billings for STF and non-firm transmission revenues in the September 2007 PEF financial forecast.

Note Q: Actual LTF OATT MW-Months are the sum of Lines 11 and 12 above, as reported in Form-1 for Firm Network Service for Others and Long Term Firm Point-to-Point Service

Note R: Actual STF/Non-Firm equivalent "MW-Months" are equal to monthly STF/Non-firm transmission service revenue divided by the same "Total Firm Monthly Trans. $/MW-Month" rate (Page 1, Line 11) from which the STF/Non-firm billing rates were derived

Note S: Section 2.12 of Schedule 10.3 states "The Formula Rate excludes all costs that are properly directly assigned or assignable to one or more particular customers, including costs directly assigned or assignable to PEF." Per Settlement of 2008 Annual Update, the amount specified excludes directly assignable retail costs/credits booked to Account 935 and retail sales tax portion of Florida sales tax audit expense booked to Account 930.2 from Form-1 reported value.

Note T: Network prepayments include interest that has been accrued but not yet refunded.

Note U: The inclusion of Line 24, "Unfunded Reserves," ensures that identified "Unfunded Reserves" are appropriately excluded from rate base in the Formula Rate calculations. The specific treatment of these "Unfunded Reserves" in no way precludes the Transmission Provider or interested parties from making any argument in any proceeding at the Commission or in any review or challenge proceeding under the Formula Rate as to the appropriate accounting or ratemaking treatment in the Formula Rate of any unfunded reserve.

Note V: Adjusted to remove ADUFC accruals from CWIP projects that were included in rate base. Qualifying CWIP excludes CWIP associated with direct assignment radials

Note W: Should PEF construct and own radials directly assignable to wholesale customers, PEF shall make a Section 205 filing to amend its Formula Rate Template to remove the costs associated with wholesale direct assignment radials from the calculation of the OATT base rates. A new attachment (e.g., Exhibit PEF-x) shall be added to the template that sets forth the direct assignment radials by customer and by facility, showing the associated monthly balances for gross plant and accumulated depreciation reserves separately by project. The intent is that the accumulated depreciation reserves be maintained separately by customer and by project to capture the associated costs by customer and to reflect the appropriate effect of the vintage of each project. Such Exhibit PEF-x shall be structured to accommodate direct assignments to multiple wholesale customers. Exhibit PEF-2 shall be modified to remove the direct assignment wholesale radials from the base rate calculations in a manner consistent with retail radials, except that Exhibit PEF-2 shall be further modified to set forth separately the costs allocated to each wholesale customer's direct assignment radials in the aggregate in separate columns. Such Section 205 filing shall be made sufficiently in advance of the first occurrence of a direct assignment wholesale transmission radial to permit the requisite modifications to the Formula Rate Template to become effective with the in-servie date of the associated facility.

PROGRESS ENERGY FLORIDA, INC.
OATT Transmission Non-Levelized Rate Formula Template Using Form-1 Data

Adjustment to Per Books PBOP Expenses

Reference for System Amount Basis in Wholesale Rates:

FLORIDA POWER CORPORATION
FERC Docket No. ER97-4573-000
Part A-T&D Services Cost Support
Section B
Supplemental Workpaper
Page 2 of 4

FLORIDA POWER CORPORATION

PBOPs

In the Company's last wholesale rate case, Docket No. ER95-469-000, accrual amounts of $1,331,000 for wholesale jurisdictional business and $22,892,000 for retail jurisdictional business were presented for the test period of calendar year 1995 on the basis of a study performed by Hewitt Associates (See attached sheet Page 3A, lines 63 & 64 for year 1995. The wholesale amount was included in the settlement cost of service for wholesale business.

A fundamental difference between the wholesale and retail components is the recognition that the wholesale component is funded in accordance with Docket No. PL93-1-000, but the retail component is not funded in accordance with Florida Public Service Commission determination.

Since the expense item needs to be stated on a system basis reflecting fully wholesale ratemaking practice for input to the transmission cost of service formula, the appropriate system figure is that imputed by dividing the wholesale component amount by the wholesale wage ratio reflected in Docket No. ER95-469-000 (See attached sheet Page 3B, line 16, total at issue). This imputation is as follows:

$1,331,000/.05998 = $ 22,191,000 (Nearest thousand)

It is the Company's understanding that this amount shall remain the same for purposes of wholesale. ratemaking until such time the Company makes a filing which is accepted by FERC that supports a revised wholesale accrual amount.

yyyy Per Book Amount:

vs. Imputed Amount

==> PBOP Expense Adjustment

Year Ending 12/31/yyyy

PROGRESS ENERGY FLORIDA, INC.
Transmission Rate Formula Support - Revenue Credits
Account 454

Description	Total	Transmission
Total Account 454	$ -	$ -

PROGRESS ENERGY FLORIDA, INC.
Transmission Rate Formula Support - Revenue Credits
Account 456

Form 1 Reference	Payment by (Column (b))	Classification (Col (d))	Rate Schedule (Col (e))	Total Revenues (Column (n))
p 328				
	Total Transmission for Others			0
	Total Classified as Non-Firm = Revenue Credit			0
	Short Term Firm - Revenue Credit			0
	Total 456 NF + STF Revenue			0
	Less Associated Ancillaries			0
	Net OATT Revenue Credit			0

PROGRESS ENERGY FLORIDA, INC.
Transmission Rate Formula Support - Account 353 Generator Step-up Transformers

	Plant	Bank	Peaker/ Unit	Book Cost	Vintage
Total				**$0**	

PROGRESS ENERGY FLORIDA, INC.

Transmission Rate Formula Support - Interconnection Facilities
Generation In-Service After March 15, 2000 per FERC Order 2003

Unit(s)	Description	Beginning Balance	Ending Balance	B/E Average
Total Interconnection Facilities		0	0	0

Exhibit PEF - 5
Page _ of _
Year Ending 12/31/yyyy

PROGRESS ENERGY FLORIDA, INC.
Accumulated Deferred Tax Detail - Prior Year

Account	Description	Accumulated Deferred Tax at 12/31/xxxx	Allocator	Factor	Result
190					
	Balance in Account 190	0			0
281					
	Balance in Account 281	0			0
282					
	Balance in Account 282	0			0
283					
	Balance in Account 283	0			0
	Total Accumulated Deferred Income Tax	0			0

PROGRESS ENERGY FLORIDA, INC.
Accumulated Deferred Tax Detail - Current Year

Account	Description	Accumulated Deferred Tax at 12/31/yyyy	Allocator	Factor	Result
190					
	Balance in Account 190	0			0
281					
	Balance in Account 281	0			0
282					
	Balance in Account 282	0			0
283					
	Balance in Account 283	0			0
	Total Accumulated Deferred Income Tax	0			0

PROGRESS ENERGY FLORIDA, INC.

Unfunded Reserves

Account	Description	Beginning Balance	Ending Balance	B/E Average	Allocator	Value	Result
	Identified Reserves:						
	Total Reserves	0	0	0			0
	Less Externally Funded Amounts:						
	Total Externally Funded Amounts	0	0	0			0
	Net Unfunded Reserves	0	0	0			0

Year Ending 12/31/yyyy

PROGRESS ENERGY FLORIDA, INC.
Transmission Rate Formula Support - List of Inputs from FERC Form-1

Page	Row	Column	Description	Reference	Beginning Balance	Ending Balance or Annual Value
111	57	c&d	Prepayments	111.57.c&d		
111	81	c&d	Loss on Reacquired Debt	111.81.c&d		
112	3	c&d	Preferred Stock Issued	112.3.c&d		
112	12	c&d	Account 216.1	112.12.c&d		
112	16	c&d	Proprietary Capital	112.16.c&d		
112	24	c&d	Long Term Debt	112.24.c&d		
113	61	c&d	Gain on Reacquired Debt	113.61.c&d		
117	62-67	c	Long Term Interest Expense	117.62-67.c		
118	29	c	Preferred Dividends (positive)	118.29.c		
200	21	c	Intangible Amort. Reserve	200.21.c		
205	5	b&g	Intangible Plant	205.5.b&g		
205	46	b&g	Production Plant	205.46.b&g		
207	58	b&g	Transmission Plant	207.58.b&g		
207	75	b&g	Distribution Plant	207.75.b&g		
207	99	b&g	General Plant	207.99.b&g		
214	47	d	Plant Held for Future Use (Trans. Only)	214.47.d		
219	21-24	c	Production Depr. Reserve	219.21-24.c		
219	25	c	Transmission Depr. Reserve	219.25.c		
219	26	c	Distribution Depr. Reserve	219.26.c		
219	27	c	General Depr. Reserve	219.27.c		
227	8	b&c	M&S - Transmission	227.8.b&c		
227	15	b&c	M&S - Stores Expense	227.15.b&c		
230a	5	b	Total Extraordniary Property Loss - Wholesale	230a.5.b		
230a	5	e	Total Extraordniary Property Loss - Wholesale	230a.5.e		
230a	5	f	Extraordinary Property Losses - Balance	230a.5.f		
234	8	b&c	ADIT - 190	234.8.b&c		
263	3	i	Other Taxes - FICA	263.3.i		
263	4	i	Other Taxes - Federal Unemployment	263.4.i		
263	7	i	Other Taxes - Highway Use	263.7.i		
263	15	i	Other Taxes - State Unemployment	263.15.i		
263	16	i	Other Taxes - Intangibles	263.16.i		
263	22	i	Other Taxes - Property County & Local	263.22.i		
266	8	f	Amortized ITC (Negative)	266.8.f		
267	8	b&h	Accum Deferred ITC - 255 (Negative)	267.8.b&h		
273	8	b&k	ADIT - 281 (Negative)	273.8.b&k		
275	2	b&k	ADIT - 282 (Negative)	275.2.b&k		
277	8	b&k	ADIT - 283 Excluding FAS 109 (Neg.)	277.8.b&k		
321	96	b	(565) Transmission of Electricity by Others	321.96.b		
321	112	b	TOTAL Transmission Expenses	321.112.b		
323	185	b	(924) Property Insurance	323.185.b		
323	189	b	(928) Regulatory Commission Expenses	323.189.b		
323	191	b	(930.1) General Advertising Expenses	323.191.b		
323	197	b	Total Admin & General Expenses	323.197.b		
335	1	b	Industry Association Dues	335.1.b		
336	1	f	Intangible Amortization	336.1.f		
336	7	f	Transmission Depr. Expense	336.7.f		
336	9	f	General Depr. Expense	336.9.f		
354	21	b	Transmission O&M Labor	354.21.b		
354	27	b	A&G Labor	354.27.b		
354	28	b	Total Direct Payroll - O&M Labor	354.28.b		
400	17	e	Firm Network Service for Self	400.17.e		
400	17	f	Firm Network Service for Others	400.17.f		
400	17	g	Long-Term Firm P-t-P Reservations	400.17.g		
400	17	h	Other Long-Term Firm Service	400.17.h		
400	17	i	Short-Term Firm P-t-P Reservations	400.17.i		

Rate Base Items from Prior Year Form 1 (Year End Value Where Not Available as Beginning Balance Above)

200	21	c	Intangible Amort. Reserve	200.21.c
214	47	d	Plant Held for Future Use (Trans Only)	214.47.d
219	21-24	c	Production Depr. Reserve	219.21-24.c
219	25	c	Transmission Depr. Reserve	219.25.c
219	26	c	Distribution Depr. Reserve	219.26.c
219	27	c	General Depr. Reserve	219.27.c
230a	5	f	Extraordinary Property Losses - Balance	230a.5.f

PROGRESS ENERGY FLORIDA, INC.

OATT Settlement - 2004 Storm Treatment

Line No.								
1	**Determination of Levelized Storm Damage Recovery Adder**							
2								
3	**Total Funding Requirements**							
4								
5	Total Funding Requirements							
6	Amortize Existing Loss	(PEF-2, Page 5, Line 4)	$13,307,907					
7	Rebuild Reserve	(PEF-2, Page 5, Line 7)	8,614,774					
8	Total 2008-2012		$21,922,681					
9	Less:							
10	Amount assumed to be collected from non-OATT service:							
11	Annual Amount	(PEF-2, Page 5, Line 8)	$368,845					
12	Five-Year Total	(Line 11 * 5)	$1,844,225					
13								
14	Net 5-Year Requirement	(Line 8 - Line 12)	$20,078,456					
15								
16	**Annual Recovery Requirements**		**2008**	**2009**	**2010**	**2011**	**2012**	**Total**
17								
18	Projected Billing Units (MW-months)							
19	LTF on OATT	(Projected and Fixed)	6,593	13,904	30,194	37,331	39,889	127,912
20	STF/Non-Firm on OATT	(Projected and Fixed)	3,000	3,000	3,000	3,000	3,000	15,000
21	Total Projected Billing Units		9,593	16,904	33,194	40,331	42,889	142,912
22								
23	Annual Percentages	(Fixed - Note P)	6.71%	11.83%	23.23%	28.22%	30.01%	100.0%
24								
25	Annual Recovery Requirements							
26	Amortize Existing Loss	(Ln 23 * Ln 6 / Ln 8 * Ln 14)	$818,184	$1,441,693	$2,831,030	$3,439,661	$3,657,824	$12,188,392
27	Rebuild Reserve	(Ln 23 * Ln 7 / Ln 8 * Ln 14)	529,645	933,269	1,832,646	2,226,639	2,367,865	7,890,064
28	Total		$1,347,829	$2,374,963	$4,663,676	$5,666,300	$6,025,688	$20,078,456
29								
30	**Levelized Storm Damage Recovery**							
31	**Adder ($/MW-mo)**	(Line 28 / Line 21)	**$140**	**$140**	**$140**	**$140**	**$140**	**$140**
32								
33	**Example Application of Levelized Adder and Annual True-Up**							
34								
35	Actual Billing Units (MW-months) (Notes Q and R)							
36	LTF on OATT	(Actual MW-Months)	0	0	0	0	0	0
37	STF/Non-Firm on OATT	(Actual Equiv. MW-Months)	0	0	0	0	0	0
38	Total Billing Units	(Line 36 + Line 37)	0	0	0	0	0	0
39								
40	Actual Recoveries of Existing Loss & Reserve Replenishment							
41	LTF on OATT	(Line 31 * Line 36)	$0	$0	$0	$0	$0	$0
42	STF/Non-Firm on OATT	(Line 31 * Line 37)	0	0	0	0	0	0
43	Total Collections	(Line 41 + Line 42)	$0	$0	$0	$0	$0	$0
44								
45	**Over(Under) Recovery to Be Reflected**							
46	**In Annual True-Ups**	(Line 43 - Line 28)	**0**	**0**	**0**	**0**	**0**	**0**
47								
49								
50	**Storm Reserve Balance Tracking:**							**2013 'til Extraordinary Loss**
51								
52	Beginning Balance		(13,307,907)	0	0	0	0	**0**
53								
54	Funding From OATT Adder	(Line 28)	0	0	0	0	0	
55	Existing Wholesale Accrual	(Line 11)	0	0	0	0	0	
56								
57	Ending Balance		0	0	0	0	0	**0**
58								
59	Maximum Reserve per Settlement		8,614,774	8,614,774	8,614,774	8,614,774	8,614,774	8,614,774
60								
61	Adjustment:		0	0	0	0	0	0

PROGRESS ENERGY FLORIDA
PREPAYMENTS FOR NETWORK UPGRADES

252 Customer advances for construction.
This account shall include advances by customers for construction which are to be refunded either wholly or in part. When a customer is refunded the entire amount to which he is entitled, according to the agreement or rule under which the advance was made the balance, if any, remaining in this account shall be credited to the respective plant account.

HYPOTHETICAL EXAMPLES

NETWORK UPGRADE COST		$ 1,000,000
DEPRECIABLE LIFE		40-YRS
ANNUAL FERC INTEREST RATE	ANNUALLY	6%
REFUND OVER 5 -YRS	ANNUALLY	$ 200,000

SCENARIO 1:

YEAR OF IN-SERVICE:

DESCRIPTION	FERC	DEBIT	CREDIT
ELEC. PLNT IN-SVC	101	$ 1,000,000	
CUSTOMER ADVANCES	252		$ 1,000,000

1st REFUND:

DESCRIPTION	FERC	DEBIT	CREDIT
CASH	130		$ 260,000
CUSTOMER ADVANCES	252	$ 200,000	
INTEREST EXP	431	$ 60,000	

	RATE BASE	EXPENSE
FORMULA INPUT - EPIS $_{YR-1}$	**$ 1,000,000**	
BEGINNING BAL.	$ (1,000,000)	
INTEREST EXPENSE $_{YR-1}$	$ (60,000)	$ 60,000
REFUND $_{YR-1}$	$ 260,000	
FORMULA INPUT $_{YR-1}$	**$ (800,000)**	**$ 60,000**
FORMULA INPUT - EPIS $_{YR-2}$	**$ 1,000,000**	
FORMULA ACCUM. DEP $_{YR-2}$	**$ (25,000)**	
BEGINNING BAL.	$ (800,000)	
INTEREST EXPENSE $_{YR-2}$	$ (48,000)	$ 48,000
REFUND $_{YR-2}$	$ 248,000	
FORMULA INPUT $_{YR-2}$	**$ (600,000)**	**$ 48,000**

SCENARIO 2:
RECOVERY OF INTEREST: PER AGREEMENT WITH CUSTOMERS, INTEREST WILL BE RECOVERED UPON PAYMENT AND NOT AS ACCRUED. THIS WILL CREATE A REGULATORY ASSET TO RECOGNIZE THE DEFERRED COST RECOVERY.

YEAR OF IN-SERVICE:

DESCRIPTION	FERC	DEBIT	CREDIT
ELEC. PLNT IN-SVC	101	$ 1,000,000	
CUSTOMER ADVANCES	252		$ 1,000,000

YR-1 NO REFUND:

DESCRIPTION	FERC	DEBIT	CREDIT
CUSTOMER ADVANCES	252		$ 60,000
INTEREST ACCRUED	431	$ 60,000	
REG ASSET (INTEREST ACCRUED)	182.3	$ 60,000	
INTEREST ACCRUED DEFERRAL	407.4		$ 60,000

YR-5 WITH REFUND:

DESCRIPTION	FERC	DEBIT	CREDIT
CUSTOMER ADVANCES	252	$ 1,338,226	
CASH	131		$ 1,338,226
REG ASSET (INTEREST ACCRUED)	182.3		$ 338,226
INTEREST ACCRUED DEFERRAL	407.3	$ 338,226	

	RATE BASE	EXPENSE
IF NOT REFUNDED UNTIL YR 5, THAN:		
BEGINNING BAL.	$ (1,000,000)	
INTEREST ACCRUED $_{YR-1}$	$ (60,000)	$ (60,000)
REG. ASSET (INTEREST ACCRUED) $_{YR-1}$	$ 60,000	$ 60,000
FORMULA INPUT $_{YR-1}$	**$ (1,000,000)**	**$ -**
INTEREST ACCRUED $_{YR-2}$	$ (63,600)	$ (63,600)
REG. ASSET (INTEREST ACCRUED) $_{YR-2}$	$ 63,600	$ 63,600
FORMULA INPUT $_{YR-2}$	**$ (1,000,000)**	**$ -**
INTEREST ACCRUED $_{YR-3}$	$ (67,416)	$ (67,416)
REG. ASSET (INTEREST ACCRUED) $_{YR-3}$	$ 67,416	$ 67,416
FORMULA INPUT $_{YR-3}$	**$ (1,000,000)**	**$ -**
INTEREST ACCRUED $_{YR-4}$	$ (71,461)	$ (71,461)
REG. ASSET (INTEREST ACCRUED) $_{YR-4}$	$ 71,461	$ 71,461
FORMULA INPUT $_{YR-4}$	**$ (1,000,000)**	**$ -**
INTEREST ACCRUED $_{YR-5}$	$ (75,749)	$ (75,749)
REG. ASSET (INTEREST ACCRUED) $_{YR-5}$	$ 75,749	$ 75,749
REFUND $_{YR-5}$	$ 1,000,000	$ 338,226
FORMULA INPUT $_{YR-5}$	**$ -**	**$ 338,226**

PROGRESS ENERGY FLORIDA, INC.

Transmission Rate Formula Support - Direct Assignment Retail Radials in Accordance with OATT Attachment U

Line	Project Description:	Project 1	Project 2	…	…	…	…	Project N	Total Projects
	Gross Plant in Service:								
1	Beginning Balance	0	0					0	0
2	Additions	0	0					0	0
3	Retirements	0	0					0	0
4	Adjustments	0	0					0	0
5	Ending Balance	0	0					0	0
6	B/E Average	0	0					0	0
	Accumulated Depreciation:								
7	Beginning Balance	0	0					0	0
8	Annual Deprecation Expen	0	0					0	0
9	Adjustments	0	0					0	0
10	Ending Balance	0	0					0	0
11	B/E Balance	0	0					0	0

PROGRESS ENERGY FLORIDA, INC.
Transmission Rate Formula Support - Depreciation Rates

The rates in the table below are those used in the calculation of depreciation expense and associated accumulated depreciation reserve amounts in the FERC Form 1 and reported and utilized on Exhibit PEF-2.

Depreciation and Amortization Rates by FERC Account	Florida PSC Approved Rate*
STEAM PRODUCTION	
Anclote Steam	
311 Structures and Improvements	1.9
312 Boiler Plant Equipment	2.2
314 Turbogenerator Units	2.8
315 Accessory Electric Equipment	1.6
316 Misc. Power Plant Equipment	1.6
Crystal River 1 & 2 Steam	
311 Structures and Improvements	2.2
312 Boiler Plant Equipment	3.7
314 Turbogenerator Units	2.5
315 Accessory Electric Equipment	2.6
316 Misc. Power Plant Equipment	2.1
Crystal River 4 & 5 Steam	
311 Structures and Improvements	1.5
312 Boiler Plant Equipment	2.5
314 Turbogenerator Units	1.0
315 Accessory Electric Equipment	1.0
316 Misc. Power Plant Equipment	2.1
Suwannee River Steam	
311 Structures and Improvements	2.3

PROGRESS ENERGY FLORIDA, INC.

Transmission Rate Formula Support - Depreciation Rates

The rates in the table below are those used in the calculation of depreciation expense and associated accumulated depreciation reserve amounts in the FERC Form 1 and reported and utilized on Exhibit PEF-2.

Depreciation and Amortization Rates by FERC Account	Florida PSC Approved Rate*
312 Boiler Plant Equipment	3.1
314 Turbogenerator Units	2.9
315 Accessory Electric Equipment	2.6
316 Misc. Power Plant Equipment	2.9
Bartow/Ancl. Pipeline	
311 Structures and Improvements	1.8
312 Boiler Plant Equipment	2.6
315 Accessory Electric Equipment	1.4
316 Misc. Power Plant Equipment	3.4
Other Steam Production	
311 Structures and Improvements	1.4
312 Boiler Plant Equipment	0.7
316 Misc. Power Plant Equipment	3.7
NUCLEAR PRODUCTION	
Crystal River #3	
321 Structures and Improvements	1.5
322 Reactor Plant Equipment	3.3
323 Turbogenerator Units	1.2
324 Accessory Electric Equipment	1.4
325 Misc. Power Plant Equipment	1.7
OTHER PRODUCTION	
Avon Park Peaking	
341 Structures and Improvements	0.6
342 Fuel Holders, Prod. and Accessories	4.8
343 Prime Movers	3.0
344 Generators	0.1
345 Accessory Electric Equipment	0.5
346 Misc. Power Plant Equipment	3.2
Bartow Peaking	
341 Structures and Improvements	1.7
342 Fuel Holders, Prod. and Accessories	3.0
343 Prime Movers	1.6

PROGRESS ENERGY FLORIDA, INC.
Transmission Rate Formula Support - Depreciation Rates

The rates in the table below are those used in the calculation of depreciation expense and associated accumulated depreciation reserve amounts in the FERC Form 1 and reported and utilized on Exhibit PEF-2.

Depreciation and Amortization Rates by FERC Account	Florida PSC Approved Rate*
344 Generators	2.1
345 Accessory Electric Equipment	1.8
346 Misc. Power Plant Equipment	0.4
Bartow Combined Cycle	
342 Fuel Holders, Prod. and Accessories	3.2
343 Prime Movers	3.3
Bayboro Peaking	
341 Structures and Improvements	1.0
342 Fuel Holders, Prod. and Accessories	3.0
343 Prime Movers	2.3
344 Generators	1.4
345 Accessory Electric Equipment	1.8
346 Misc. Power Plant Equipment	1.1
Debary Peaking	
341 Structures and Improvements	2.7
342 Fuel Holders, Prod. and Accessories	2.6
343 Prime Movers	3.0
344 Generators	2.4
345 Accessory Electric Equipment	2.5
346 Misc. Power Plant Equipment	3.3
Debary Peaking P7-1 (New)	
341 Structures and Improvements	3.3
342 Fuel Holders, Prod. and Accessories	4.0
343 Prime Movers	3.7
344 Generators	3.3
345 Accessory Electric Equipment	3.4
346 Misc. Power Plant Equipment	4.2
Higgins Peaking	
341 Structures and Improvements	2.9
342 Fuel Holders, Prod. and Accessories	5.4
343 Prime Movers	2.9

PROGRESS ENERGY FLORIDA, INC.
Transmission Rate Formula Support - Depreciation Rates

The rates in the table below are those used in the calculation of depreciation expense and associated accumulated depreciation reserve amounts in the FERC Form 1 and reported and utilized on Exhibit PEF-2.

Depreciation and Amortization Rates by FERC Account	Florida PSC Approved Rate*
344 Generators	2.5
345 Accessory Electric Equipment	3.3
346 Misc. Power Plant Equipment	4.6
Hines Energy Complex	
341 Structures and Improvements	2.9
342 Fuel Holders, Prod. and Accessories	3.2
343 Prime Movers	3.2
344 Generators	2.9
345 Accessory Electric Equipment	3.2
346 Misc. Power Plant Equipment	3.1
Hines Energy Complex Unit # 2	
341 Structures and Improvements	2.9
342 Fuel Holders, Prod. and Accessories	3.2
343 Prime Movers	3.3
344 Generators	2.9
345 Accessory Electric Equipment	3.2
346 Misc. Power Plant Equipment	3.1
Hines Energy Complex Unit # 3	
341 Structures and Improvements	2.9
342 Fuel Holders, Prod. and Accessories	3.2
343 Prime Movers	3.3
344 Generators	2.9
345 Accessory Electric Equipment	3.2
346 Misc. Power Plant Equipment	3.1
Hines Energy Complex Unit # 4	
341 Structures and Improvements	2.9
342 Fuel Holders, Prod. and Accessories	3.2
343 Prime Movers	3.3
344 Generators	2.9
345 Accessory Electric Equipment	3.2
346 Misc. Power Plant Equipment	3.1

PROGRESS ENERGY FLORIDA, INC.
Transmission Rate Formula Support - Depreciation Rates

The rates in the table below are those used in the calculation of depreciation expense and associated accumulated depreciation reserve amounts in the FERC Form 1 and reported and utilized on Exhibit PEF-2.

Depreciation and Amortization Rates by FERC Account	Florida PSC Approved Rate*
Intercession City Peak # 11	
341 Structures and Improvements	4.0
342 Fuel Holders, Prod. and Accessories	4.4
343 Prime Movers	4.6
344 Generators	4.0
345 Accessory Electric Equipment	4.0
346 Misc. Power Plant Equipment	3.8
Intercession City Peak P1-P6	
341 Structures and Improvements	2.9
342 Fuel Holders, Prod. and Accessories	6.6
343 Prime Movers	2.7
344 Generators	2.6
345 Accessory Electric Equipment	3.1
346 Misc. Power Plant Equipment	5.5
Intercession City Peak P12-P14	
341 Structures and Improvements	2.8
342 Fuel Holders, Prod. and Accessories	3.0
343 Prime Movers	2.9
344 Generators	2.5
345 Accessory Electric Equipment	2.6
346 Misc. Power Plant Equipment	3.1
Intercession City Peak P7-P10	
341 Structures and Improvements	2.5
342 Fuel Holders, Prod. and Accessories	2.8
343 Prime Movers	2.6
344 Generators	2.5
345 Accessory Electric Equipment	2.5
346 Misc. Power Plant Equipment	2.3

PROGRESS ENERGY FLORIDA, INC.

Transmission Rate Formula Support - Depreciation Rates

The rates in the table below are those used in the calculation of depreciation expense and associated accumulated depreciation reserve amounts in the FERC Form 1 and reported and utilized on Exhibit PEF-2.

Depreciation and Amortization Rates by FERC Account	Florida PSC Approved Rate*
Rio Pinar Peaking	
341 Structures and Improvements	3.2
342 Fuel Holders, Prod. and Accessories	4.0
343 Prime Movers	2.3
344 Generators	2.3
345 Accessory Electric Equipment	4.2
346 Misc. Power Plant Equipment	8.6
Suwannee River Peaking	
341 Structures and Improvements	1.3
342 Fuel Holders, Prod. and Accessories	3.3
343 Prime Movers	1.3
344 Generators	1.4
345 Accessory Electric Equipment	1.8
346 Misc. Power Plant Equipment	3.2
Tiger Bay Cogen	
341 Structures and Improvements	1.7
342 Fuel Holders, Prod. and Accessories	1.8
343 Prime Movers	1.4
344 Generators	1.8
345 Accessory Electric Equipment	2.1
346 Misc. Power Plant Equipment	1.4
Turner Peaking	
341 Structures and Improvements	2.0
342 Fuel Holders, Prod. and Accessories	3.0
343 Prime Movers	1.2
344 Generators	2.4
345 Accessory Electric Equipment	3.0
346 Misc. Power Plant Equipment	2.1
University of Fla Cogen	
341 Structures and Improvements	1.8
342 Fuel Holders, Prod. and Accessories	2.0
343 Prime Movers	2.5
344 Generators	1.8
345 Accessory Electric Equipment	1.9

PROGRESS ENERGY FLORIDA, INC.

Transmission Rate Formula Support - Depreciation Rates

The rates in the table below are those used in the calculation of depreciation expense and associated accumulated depreciation reserve amounts in the FERC Form 1 and reported and utilized on Exhibit PEF-2.

Depreciation and Amortization Rates by FERC Account	Florida PSC Approved Rate*
346 Misc. Power Plant Equipment	1.5
System-Other	
346 Misc. Power Plant Equipment	1.5
DISTRIBUTION PLANT	
360.10 Land Rights	1.4
361.00 Structures and Improvements	1.4
362.00 Station Equipment	1.8
364.00 Poles, Towers and Fixtures	4.2
365.00 Overhead Conductors and Devices	2.7
366.00 Underground Conduit	1.6
367.00 Underground Conductors and Devices	3.0
368.00 Line Transformers	2.9
369.10 Services-Overhead	4.0
369.20 Services-Underground	2.2
370.00 Meters	6.0
371.00 Installation on Customers Premises	3.6
373.00 Street Lighting and Signal Systems	3.1
TRANSMISSION PLANT	
350.10 Land Rights	1.2
352.00 Structures and Improvements	1.4
353.10 Station Equipment	1.8
353.20 Station Equipment-Station Control	1.1
354.00 Towers and Fixtures	1.3
355.00 Poles and Fixtures	3.3
356.00 Overhead Conductors and Devices	1.9
357.00 Underground Conduit	1.2
358.00 Underground Conductors & Devices	2.0
359.00 Roads and Trails	0.9
General Plant	
390.00 Structures and Improvements	3.7
391.00 Office Furniture and Equipment	14.3

PROGRESS ENERGY FLORIDA, INC.

Transmission Rate Formula Support - Depreciation Rates

The rates in the table below are those used in the calculation of depreciation expense and associated accumulated depreciation reserve amounts in the FERC Form 1 and reported and utilized on Exhibit PEF-2.

Depreciation and Amortization Rates by FERC Account	**Florida PSC Approved Rate***
Transportation Equipment	
392.10 Passenger Cars	8.7
392.20 Light Trucks	8.7
392.30 Heavy Trucks	4.8
392.40 Special Trucks	5.0
392.50 Trailers	1.7
393.00 Stores Equipment	14.3
394.00 Tools, Shop and Garage Equipment	14.3
395.00 Laboratory Equipment	14.3
396.00 Power Operated Equipment	5.8
397.00 Communication Equipment	14.3
398.00 Miscellaneous Equipment	14.3
Intangible Plant	
302.00 Franchise Costs	3.3
303.00 Intangible Plant	20.0
303.00 Misc Intangible Plant	14.3
303.10 Customer Service System (CSS)	10.0

* All rates are those approved in the FPSC ORDER NO. PSC-10-0131-FOF-EI, DOCKET NOS. 090079-EI, 090144-EI, 090145-EI, with the exception of Intangible Plant which was not addressed in the 2009 Rate Case.

Consistent with Section 1(h)(i) of Schedule 10-A.1 Formula Rate Implementation Protocols, the depreciation rates are not subject to change except pursuant to a Section 205 or 206 filing under the Federal Power Act.

SCHEDULE ~~10.3~~10-A.3

Notes for Formula Rate

[FPC Zone]

Section 1 General Instruction

The following notes to the Formula Rate template in Schedule ~~10.2~~10-A.2 of the Tariff of the Transmission Provider (also referred to herein as "PEF") shall govern the use and application of the Formula Rate and constitute an integral part of the Formula Rate.

Section 2 Notes

2.1 Order No. 679 Transmission Incentives.

(i) PEF shall not make an Order No. 679 transmission incentives filing for its transmission construction projects during an approximately four-year period of time that extends from the date hereof through December 31, 2011 (the "Order No. 679 Rate Moratorium").[~~4~~1] PEF shall have the right to file for Order No. 679 transmission incentives for its transmission construction projects that meet the criteria under Section ~~3.2~~2.1(ii) below after December 31, 2011, and the Customers reserve the right to oppose any such filing; provided, however, that a condition precedent to any such filing by PEF is that PEF shall have provided written notice to the Customers at least ninety (90) days prior to such filing of PEF's intent to make such filing. Thus, for example, if PEF intends to make such an Order 679 transmission incentives filing on March 1, 2012, it would be required to provide written notice of such filing on or before December 2, 2011, failing which the filing would be a nullity.

[~~4~~1] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, 72 Fed. Reg. 1,152 (January 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007). The reference herein to "Order No. 679" includes any order issued by the FERC prior or subsequent to the filing of this Settlement Agreement that pertains to rate incentives of any sort for construction of transmission facilities.

(ii) After the Order No. 679 Rate Moratorium expires and provided that proper advance notice is provided in accordance with Section ~~3.2~~2.1(i) above, PEF may file at the Commission for any transmission incentives for its transmission construction projects that are permitted by Order No. 679, except that PEF may not file for transmission incentives for any transmission construction project that has reached a point in development in which costs of the transmission project have begun to be capitalized by PEF (*i.e.*, PEF has begun the accrual of costs for the transmission construction project in Account 107 in accordance with generally accepted accounting practices) during the Order No. 679 Rate Moratorium. PEF may not intentionally delay or defer the accrual of costs for a transmission construction project in Account 107 in order to make a transmission construction project eligible for Order No. 679 transmission incentives.

2.2 50% CWIP Recovery. The Formula Rate includes 50% recovery of the average of the beginning and end-of-year CWIP balances only for those transmission projects identified in the Formula Rate Filing. PEF agrees that the submission for 50% CWIP recovery shall be filed in accordance with the requirements in the Commission's regulations (18 C.F.R. § 35.25(f)) and existing precedent on the issue (including *Northeast Utilities Service Company*, 114 FERC ¶ 61,089 (2006); *Boston Edison Company*, 109 FERC ¶ 61,300 (2004), *order on reh'g*, 111 FERC ¶ 61,266 (2005); and *United Illuminating Company*, Docket Nos. ER05-1049-000 *et al.*, Letter Order). PEF agrees that the submission shall make CWIP showings and waiver requests that are comparable to the showings and waiver requests that were submitted and accepted by the Commission in the aforementioned cases. Consistent with then applicable Commission regulations and precedent, PEF must make a FPA Section 205 filing if it wishes to request 50% CWIP recovery for any additional transmission projects in the future.

2.3 ROE.

(i) The Formula Rate shall include a 10.8% rate of return on common equity ("ROE"). PEF and each of the Customers shall have no FPA Section 205 or 206 rights, respectively, to seek a change to the ROE in the Formula Rate during the period of the Order No. 679 Rate Moratorium. PEF and each of the Customers shall have FPA Section 205 or 206 rights, respectively, to seek a change to the ROE in the Formula Rate after the expiration of the Order No. 679 Rate Moratorium.

2.4 Storm Damage.

(i) With respect to the amortization of prior extraordinary property losses recorded in FERC Account 182.1 in connection with the series of four hurricanes that damaged the PEF transmission system during a six-week period in 2004, the Formula Rate shall amortize this existing extraordinary loss over a five-year period beginning January 1, 2008, and the annual amortization shall be calculated in accordance with the methodology included in the Formula Rate.

(ii) The Formula Rate shall include an accrual to rebuild the wholesale storm reserve balance over a five-year period beginning January 1, 2008, and the accrual shall be calculated in accordance with the methodology included in the Formula Rate. These storm damage reserve accruals are subject to the cap set forth in Section ~~3.5~~2.4(iv). The Formula Rate shall not include accruals to rebuild the wholesale storm reserve balance as a result of the 2004 hurricanes after the end of the five-year recovery period.

(iii) The Formula Rate shall include an ongoing accrual assigned to wholesale customers for storm damage reserve of $434,000 each year. These ongoing accruals are subject to the cap set forth in Section ~~3.5~~2.4(iv).

(iv) The accruals described in Section ~~3.5~~2.4(ii) and(iii) shall be subject to a cap to ensure that there is no over-funding of storm damage reserve funds. Under the cap, the total accruals in each year shall be subject to reduction (and possible reversal to negative amounts) as necessary to avoid over-funding the wholesale portion of the storm damage reserve funds, i.e., in order to maintain the wholesale portion of PEF's storm reserve fund balance at no more than the transmission allocated portion of the $140.2 million maximum storm damage reserve level.

(v) To ensure that there is no double recovery of storm damage reserve accruals, the Formula Rate shall exclude the accruals, described in Sections ~~3.5~~2.4(i), (ii) and (iii), from FERC Account 924 and all other expenses included in the Formula Rate.

(vi) The Formula Rate includes a worksheet that illustrates the methodology for the storm damage recovery described in Sections ~~3.5~~2.4(i) and (ii).

2.5 Transmission Divisor.

(i) The transmission load divisor in the Formula Rate shall be determined in the following manner:

(1) For Network Integration Service under the OATT and for transmission services similar to Network Integration Service under the OATT (*e.g.*, PEF's service to its native load and service under certain grandfathered agreements), except those services identified in item (2), the transmission load divisor shall include the actual demands of those transmission customers at the time of PEF's monthly transmission system peaks.

(2) For Network Contract Demand Service under the OATT and transmission services similar to Network Contract Demand Service under the OATT (*e.g.*, PEF's service under certain grandfathered agreements), the transmission load divisor shall include the contract demands of those transmission customers at the time of PEF's monthly transmission system peaks.

(3) For Long-Term Firm Point-to-Point Transmission Service and Conditional Firm Service under the OATT and transmission service similar to Long-Term Firm Point-to-Point Transmission Service or Conditional Firm Service under the OATT (*e.g.*, PEF's service under certain grandfathered agreements), the transmission load divisor shall include the contract demands of those transmission customers at the time of PEF's monthly transmission system peaks.

(4) For Short-Term Firm or Non-Firm Transmission Services under the OATT and transmission service similar to Short-Term Firm or Non-Firm Transmission Services under the OATT (*e.g.*, PEF's service under certain grandfathered agreements), the transmission load divisor shall not include the contract demands of those transmission customers (because revenues from these services are treated as a revenue credit in the Formula Rate, as set forth in Section ~~3.7~~2.6(i)(2)).

(5) All values in the transmission load divisor will be adjusted for losses to the transmission system input level based on the transmission loss factor set forth in the OATT.

2.6 Non-load and Transmission-related Revenue Credits.

(i) The non-load and transmission-related revenue credits in the Formula Rate shall be determined in the following manner:

(1) All revenues associated with facilities allocated to the transmission function, including both direct and indirect allocations (e.g., general and intangible plant and administrative and general expense) shall be treated as revenue credits in the Formula Rate, with the exception that transmission services that are included in the transmission divisor of the Formula Rate, as set forth in Section ~~3.6,~~2.5, shall not be treated as a revenue credit. Such revenue credits shall include, but shall not be limited to, transmission facilities lease/rental payments, direct assignment facilities charges, pole attachment fees, and general plant-related income.

(2) Transmission revenues from Short-Term Firm and Non-Firm Transmission Services under the OATT and transmission service similar to Short-Term Firm or Non-Firm Transmission Services under the OATT (e.g., PEF's service under certain grandfathered agreements) shall be treated as revenue credits in the Formula Rate.

(3) Transmission services revenues from FERC Account 456 shall be treated as revenue credits in the Formula Rate, but ancillary services revenues from FERC Account 456 shall not be revenue credits in the Formula Rate.

(4) All transmission revenue credits shall be directly assigned to the transmission function in the Formula Rate (i.e., they shall not be allocated in the Formula Rate using a transmission plant allocator).

(5) Revenues associated with indirect allocations of costs to the transmission function (e.g., general and intangible plant) shall be allocated to the transmission function in the Formula Rate based on the same underlying

indirect allocations of costs and treated as a revenue credit.

2.7 Average of Beginning and End-of-Year Data: The Formula Rate shall include the average of the beginning and end-of-year balances from PEF's FERC Form No. 1 reports for the rate base items included in the Formula Rate, with the exception that storm damage items shall be included in the Formula Rate in accordance with Section ~~3.5.~~2.4.

2.8 Cash Working Capital. The Formula Rate shall include cash working capital based on a formulary approach as follows: 1/8 multiplied by the total of operation and maintenance expense, as specified in the Formula Rate template ~~attached to this Settlement Agreement,~~ at page 3, line 17.

2.9 Prepayments for Network Upgrades by Generators. The Formula Rate includes treatment of refundable prepayments made by generators for network upgrades. The Formula Rate includes the amount of the refundable prepayments that PEF has not refunded to the OATT transmission customer in credits to the OATT transmission customer's transmission charges as an offset to rate base in the Formula Rate so that PEF will not earn a return on those funds. Correspondingly, the amount of interest paid to OATT transmission customers as their balances are credited against their transmission service is included as an expense in the Formula Rate. The Formula Rate includes a hypothetical example to illustrate how refundable prepayments for network upgrades are treated in the Formula Rate. The Formula Rate includes a placeholder for any future refundable prepayments for network upgrades.

2.10 Credits for Customer-owned Facilities. The Formula Rate includes a placeholder for any future credits for customer-owned facilities to prevent any under-recovery of revenues by PEF due to any credits provided to OATT transmission customers for their own facilities.

2.11 Transmission Provider's Compliance with Order No. 2003. In accordance with

FERC Order No. 2003,[52] the Formula Rate excludes any transmission plant that meets the definition of "Interconnection Facilities" and was placed in service for PEF's own generation facilities after March 15, 2000.

2.12 Directly Assigned or Assignable Costs. The Formula Rate excludes all costs that are properly directly assigned or assignable to one or more particular customers, including costs directly assigned or assignable to PEF.

2.13 PEF Payments to "Affected Transmission Owners" and Receipts from others under the Regional Cost Allocation. FRCC regional transmission expansion cost allocation principles are currently under development. Within thirty days after those principles are filed as part of a FERC Order 890 compliance filing, PEF shall submit to Transmission Customers a proposal to address the treatment under the Formula Rate of PEF payments to Affected Transmission Owners, and payments to PEF as an Affected Transmission Owner, under such principles. If the interested Transmission Customers and PEF reach agreement within ninety days, PEF shall make a filing, pursuant to FPA Section 205, to change the Formula Rate to properly account for such payments. If the interested Transmission Customers and PEF do not reach agreement within ninety days, PEF shall make a filing, pursuant to FPA Section 205, to change the Formula Rate to properly account for such payments, and such filing may be opposed by affected parties. PEF's FPA Section 205 filing to implement the FRCC regional transmission expansion cost allocation principles into the Formula Rate shall be limited to that subject matter and any Transmission Customer opposition to said FPA Section 205 filing shall be limited to disputes as to how to implement the FRCC regional

52 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,846 (August 19, 2003), FERC Stats. & Regs., ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, 69 Fed. Reg. 15,932 (March 26, 2004), FERC Stats. & Regs., ¶ 31,160 (2004), *order on reh'g*, Order No. 2003-B, 70 Fed. Reg. 265 (January 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, 70 Fed. Reg. 37, 661 (June 30, 2005), FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

transmission expansion cost allocation principles into the Formula Rate. To the extent necessary, PEF's said Section 205 filing may receive a retroactive effective date to permit PEF to recover costs resulting from the FRCC regional transmission expansion cost allocation principles.

2.14 Accumulated Deferred Income Taxes (ADIT).

The Formula Rate provides for the inclusion of transmission-related ADIT in the rate base. ADIT items unrelated to transmission shall not be allocated to transmission. In each Annual Update (as defined in the Formula Rate Implementation Protocols), PEF shall provide a spreadsheet that identifies the transmission-related costs in the FERC Form No. 1 reported amounts for ADIT. For example, the following ADIT items are not included in the Formula Rate because they are not transmission-related ADIT:

(i) Income tax deficiency items in ADIT (e.g., Accounts 190 and 283) are assigned to "other" in the Formula Rate.

(ii) Deferred taxes related to Environmental Cleanup Reserve in ADIT are allocated on the basis of gross plant in the Formula Rate.

(iii) Pension-related taxes, referred to as "Prepaid Pension - per book" and "Reg Asset - Minimum Pension Liab," in Account 283 are excluded from rate base in the Formula Rate and, accordingly, there shall be no ADIT balance offset for these items.

2.15 Intangible Plant.

(i) The Formula Rate includes the treatment of intangible plant.

(ii) In future Annual Updates, PEF shall provide supporting information concerning gross intangible plant investment and associated depreciation in order to establish net intangible plant investments so that OATT transmission customers may compare PEF's net intangible plant investments from year to year.

(iii) To the extent that the net intangible plant investment increases from one year to the next, PEF shall supply, in the Annual Update, the supporting information to explain the increase and PEF shall adjust the allocation of net intangible plant investment in the Formula Rate to the extent necessary to reflect an appropriate allocation to transmission. This adjustment shall be submitted by PEF to the Commission in PEF's Annual Informational Filing for the Commission's acceptance. If there is a disagreement between PEF and a transmission customer concerning this matter, such matter shall be resolved through a Preliminary Challenge and/or Formal Challenge under the Formula Rate Implementation Protocols (rather than through an FPA Section 206 complaint).

2.16 Prepaid Pension Expense and Other Prepayments.

(i) The Formula Rate shall exclude prepaid pension expenses from rate base.

(ii) To the extent that prepaid pension expenses increase in a given year, PEF shall in the Annual Update provide supporting information for, and shall adjust the allocation of prepaid expenses, to the extent necessary to reflect an appropriate allocation to transmission. This adjustment shall be submitted by PEF to the Commission in PEF's Annual Informational Filing for the Commission's acceptance. If there is a disagreement between PEF and a transmission customer concerning this matter, such matter shall be resolved through a Preliminary Challenge and/or Formal Challenge under the Formula Rate Implementation Protocols (rather than through an FPA Section 206 complaint).

2.17 Extraordinary Property Loss. If an event meets the requirements for treatment as an Extraordinary Property Loss (FERC Account 182.1), PEF shall seek Commission approval for such treatment, with charges amortized over 3 to 5 years, as appropriate under the circumstances.

2.18 Extraordinary Transmission O&M Expenses. O&M expenses allocated or assigned to the transmission function that are extraordinary and non-recurring and have a significant effect on charges shall be amortized in the Formula Rate over three to five years (subject to Commission approval), as appropriate under the circumstances. The Formula Rate shall include the unamortized balance in rate base.

2.19 Property Taxes. Property taxes shall be allocated in the Formula Rate using the gross plant allocator.

2.20 Property Insurance. After deducting the annual funding of self-insurance for storm damage, property insurance shall be allocated in the Formula Rate using the gross plant allocator.

2.21 PEF Power Marketing Costs.

(i) To the extent that any labor costs associated with PEF's power marketing operations are included in administrative and general ("A&G") expense accounts, those labor costs shall be excluded from the A&G expenses to be allocated in the Formula Rate.

(ii) The divisor of the labor allocator in the Formula Rate shall include any such labor costs associated with PEF's power marketing operations.

2.22 FERC Account 561.

(i) Consistent with Order No. 668, the Formula Rate reflects the appropriate treatment of the series of sub-accounts under Account 561 such that the Formula Rate includes only those items associated with transmission service and excludes all other costs, such as costs properly chargeable to Schedule 1 – Load Control and Dispatch Service.

(ii) The Formula Rate Filing does not change PEF's existing filed rate for Schedule 1 – Load Control and Dispatch Service in the ~~PEF OATT~~Tariff.

2.23 Asset Retirement Obligations. The Formula Rate shall not include asset retirement obligations in any plant investment.

2.24 A&G Expenses. The Formula Rate shall exclude industry association dues and research and development fees from administrative and general expenses recovered in the Formula Rate.

SCHEDULE 10-B

NETWORK INTEGRATION TRANSMISSION SERVICE

FORMULA RATE FOR DETERMINATION OF ANNUAL TRANSMISSION REVENUE REQUIREMENT AND SCHEDULE 1 ANNUAL REVENUE REQUIREMENT

[DEC Zone]

This Schedule contains the Formula Rate that the Transmission Provider will use to determine its Annual Transmission Revenue Requirement and its Schedule 1 Annual Revenue Requirement (together, "Formula Rates"), and the implemental protocols for the Formula Rates ("Formula Rate Implementation Protocols"). The Formula Rate Implementation Protocols are included as Exhibit A to this Schedule, and apply to the Transmission Provider's calculation of its Annual Transmission Revenue Requirement and its Schedule 1 Annual Revenue Requirement. The Formula Rate for the Transmission Provider's Annual Transmission Revenue Requirement is included in Exhibit B to this Schedule, and shall be used to calculate the Transmission Provider's charges under Schedule 7 and Attachment H of this Tariff. The Formula Rate for the Transmission Provider's Schedule 1 Annual Revenue Requirement is included in Exhibit B to this Schedule, and shall be used to calculate the Transmission Provider's charges under Schedule 1 of this Tariff.

EXHIBIT A TO SCHEDULE 10-B
DUKE ENERGY CAROLINAS FORMULA RATE
IMPLEMENTATION PROTOCOLS

Section 1: General

a) **Formula Rates**.[1] Duke Energy Carolinas employs a Formula to calculate its base transmission rates (for Network Integration Transmission Service and Point-to-Point Transmission Service) and a Formula to calculate its rates for Schedule 1- Scheduling, System Control and Dispatch Service ("Schedule 1 Service"), which rates are recalculated annually, based on calendar year costs, by means of the Formulas[2], in accordance with the Protocols set forth herein. The Formula, the Formula Rate Principles, and these Protocols together comprise the filed rate ("Formula Rate") of Duke Energy Carolinas. Each year Duke Energy Carolinas prepares an Annual Update that trues up the transmission rates calculation by populating the Formula Rate with information from Duke Energy Carolinas' Federal Energy Regulatory Commission ("FERC" or the "Commission") Form No. 1 and its books and records for the preceding calendar year and prepares Estimated Billing Rates for the next Billing Year. Duke Energy Carolinas provides on the last page of these Protocols a time-line/chart illustrating the preparation of the Annual Update, the true-up, and the Estimated Billing Rates. The Annual Update process does not effect change to the Formula Rate itself.

b) **Changes in Rates**. Provisions of the Formula Rate may not be changed by Duke Energy Carolinas except through an appropriate filing pursuant to Section 205 of the Federal Power Act ("FPA") and FERC's regulations thereunder. Provisions of the Formula Rate may not be changed by any other party except pursuant to an order of FERC issued under Section 206 of the FPA. However, Duke Energy Carolinas may, at its discretion and at a time of its choosing, make a limited filing pursuant to FPA Section 205 to update the references in the Formula Rate to reflect any FERC changes to the format and/or content of the FERC Form No. 1 or the Uniform System of Accounts ("USoA") that affect the calculations set forth in the Formula Rate. The sole issue in any such limited Section 205 filing shall be whether such proposed changes appropriately reflect the changes to the format and/or content of the FERC Form No. 1 or the USoA and whether such changes are just and reasonable, and shall not include other aspects of the Formula Rate.

c) **Stated Values**. Values included in the Formula Rate (if any) for the following items (hereinafter, "Stated Values") may not be changed by Duke Energy Carolinas except through a full rate case filing pursuant to FPA Section 205 or by any other

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[1] The descriptive headings of the various Sections and subsections of these Protocols have been inserted for convenience of reference only and in no way shall be deemed to modify or restrict any of the terms or provisions hereof.

[2] Hereafter in these Protocols the term "Formula" is used to refer respectively to the Formula used to calculate base transmission rates (for Network Integration Transmission Service and Point-to-Point Transmission Service) and the Formula used to calculate rates for Schedule 1- Scheduling, System Control and Dispatch Service.

party except pursuant to an order of FERC issued under Section 206 of the FPA:[3]

(i) rate of return on common equity;

(ii) cap on equity component of capital structure;

(iii) the depreciation and/or amortization rates as set forth in the notes to the Formula Rate template, and composite rate methods;

(iv) Post-Retirement Benefits Other than Pensions ("PBOPs"), pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for PBOP;

(v) amortization of extraordinary property losses;

(vi) abandoned plant costs;

(vii) transmission incentives;

(viii) construction work in progress;

(ix) GridSouth costs and amortization; and

(x) revenue-related tax factor.[4]

d) **Fundamental Predicates**. The Formula Rate is premised upon data reported or recorded by Duke Energy Carolinas consistent with the following predicates ("Fundamental Predicates"):

(i) FERC's USoA,

(ii) applicable FERC Form No. 1 reporting requirements,

(iii) FERC's policies governing formula rates for wholesale transmission service, including FERC's policies that all charges billed under formula rates are subject to: (A) challenge on grounds of imprudence, and (B) an order by FERC requiring after-the-fact refunds.

(iv) FERC orders establishing transmission ratemaking policies of general application to transmission-owning public utilities, including Duke Energy Carolinas; and

(v) the accounting and cost allocation policies, practices and procedures of Duke Energy Carolinas to the extent consistent with the authorities listed in (i) through (iv) above.

The Formula Rate is based upon each of these Fundamental Predicates as it existed as of the date these Protocols are filed with FERC. Provisions of the Formula Rate may be modified to conform to changes in these Fundamental Predicates in

[3] The initial Stated Values for amortization of extraordinary property losses, abandoned plant costs, transmission incentives and construction work in progress will be $0. Duke is required to make a full rate case filing under Section 205 of the Federal Power Act to change these Stated Values.

[4] The initial Stated Values for revenue-related tax factor is will be 1. Duke is required to make a full rate case filing under Section 205 of the Federal Power Act to change this Stated Value.

accordance with Sections 1(b) or 3(c) of these Protocols or as ordered by FERC.

e) **Year, Billing Year**. Unless otherwise indicated, the term "year" in these Protocols means a calendar year starting January 1 and ending December 31. The term "Billing Year" means the period starting June 1 and ending May 31.

f) **Interest Rate**. The interest rate for all interest calculations provided for under these Protocols shall be the FERC interest rate on refunds set forth in 18 C.F.R. § 35.19a(a)(2)(iii)(A).

Section 2: Annual Update Process

a) **General**. On or before May 15 of each year, Duke Energy Carolinas shall

(i) recalculate its Annual Transmission Revenue Requirement and its Annual Revenue Requirement for Schedule 1 services for the preceding year (both of which are encompassed by the term "ATRR," as used herein) by populating the Formula Rate with information from Duke Energy Carolinas' FERC Form No. 1 and its books and records for the preceding calendar year ("Annual Update"),

(ii) post each such Annual Update on its website via link to the public portion of its OASIS website,

(iii) submit such Annual Update to FERC as an informational filing,

(iv) perform a true-up of the rates for the immediately preceding year as set forth in Section 2 (h), and

(v) establish Estimated Billing Rates for the immediately succeeding Billing Year as set forth in Section 2 (i).

b) **Service on Customers**. On the Publication Date, Duke Energy Carolinas will electronically serve on each network transmission customer and each transmission customer that takes point-to-point service under the Tariff pursuant to a contract of one year or longer in duration (collectively "Customers") the following: (i) a "workable," fully-functioning electronic spreadsheet containing that year's Annual Update input data; (ii) transmission load data for the preceding year, showing monthly coincident and non-coincident peak transmission loads for each Customer and other users of the Duke Energy Carolinas transmission system (including company loads); and (iii) a specification of the monthly transmission loads used in developing the updated rate divisor, and an explanation of any adjustments made to the transmission load data in deriving that divisor.

c) **Informational Filing**. The informational filing with FERC is not intended to be subject to FERC's notice requirements, but any such lack of notice does not limit FERC's authority to initiate a proceeding on its own motion. If FERC does issue a notice of the informational filing, Duke Energy Carolinas shall advise FERC of the challenge process in the Protocols and shall request an abeyance of the noticed FERC proceeding to permit the Protocol challenge process to proceed.

d) **Next Business Day**. If the date for making the Annual Update posting/filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall be due on the next business day.

e) **Publication Date**. The date on which the last of the events listed in Section 2.a (i) - (iii) occurs shall be that year's "Publication Date."

f) **Annual Update**. The Annual Update for the year:

(i) shall be based upon data properly recordable and correctly recorded in Duke Energy Carolinas' FERC Form No. 1 for the most recent year, and upon the books and records of Duke Energy Carolinas, consistent with FERC accounting policies and FERC's USoA;

(ii) shall, to the extent specified in the Formula Rate, provide supporting documentation for data not otherwise available in the FERC Form No. 1 that are used in the Formula Rate;[5]

(iii) shall identify any changes in (1) FERC's USoA; (2) FERC Form No. 1 reporting requirements as applicable[6]; and/or (3) Duke Energy Carolinas' accounting policies and practices and procedures, to the extent that such changes have occurred since the posting of the most recent Annual Update, and have a material effect, singularly or in the aggregate, on an annualized basis on the determination of any value(s) included in the Formula Rate or the calculation of the Annual Update, as applicable;

(iv) shall be subject to challenge and review only in accordance with the procedures set forth in these Protocols; and

(v) shall not result in modifications to the Formula Rate.

g) **Projection**. The Annual Update shall include a budgetary projection, broken out on an annual basis, of total transmission plant anticipated to be placed in service over each of the next three years and shall include disclosure of any projected costs associated with Smart Grid activities, including transmission equipment, software, hardware, and operations and maintenance expenses. Such projection shall be based upon Duke Energy Carolinas' then-current estimate of future expenditures but shall not otherwise be binding on Duke Energy Carolinas in any way. For each project with an estimated cost at or above $5 million, Duke Energy Carolinas shall provide identification of: (1) the name and description of each such project; (2) the anticipated project completion date; (3) identification of the transmission constraint, reliability concern or criteria violation that the project is intended to relieve or avoid; and (4) the expected expenditure on each such project, by year for the three-year period.

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5 Each input to the Formula Rate will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information.

6 If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

h) **True-Up**. As part of the Annual Update process,

(i) Duke Energy Carolinas will calculate separate True-Up Amounts for Network Integration Transmission Service, Point-to-Point Transmission Service, and Schedule 1 Service. Each True-Up Amount shall be equal to the difference between (1) the amount of revenue that Duke Energy Carolinas collected[7] from its Network Integration Transmission Service customers, Point-to-Point Transmission Service customers, or Schedule 1 Service customers, as applicable, during the immediately preceding calendar year[8] and (2) the amount of revenue that Duke Energy Carolinas would have collected from such customers under the actual ATRR and transmission rates as calculated pursuant to the Annual Update.

(ii) Each annual True-Up Amount will be spread evenly over the calendar year to which the True-Up Amount relates. Thus, each True-Up Amount is divided by 12 and interest is applied to the twelve monthly balances for such calendar year for the appropriate number of months until June 1 of the year in which the Annual Update is performed.

(iii) An equal monthly amount is then calculated that will recover each True-Up Amount, plus accrued interest until June 1 as calculated pursuant to subsection (ii), plus interest that will accrue over the next Billing Year (June 1 to May 31). The sum of these 12 monthly amounts ("True-Up Amount With Interest") is then divided by the load ratio share percentage for the immediately preceding year and the result is added to (or subtracted from) the ATRR which will be the basis for Estimated Billing Rates for the immediately subsequent Billing Year.

(iv) The Formula Rate contains calculations of a True-Up Amount With Interest for Network Integration Transmission Service and for Schedule 1 Service.

i) **Estimated Billing Rates**. No later than May 15 of each year, Duke Energy Carolinas shall prepare estimated billing rates ("Estimated Billing Rates") for the next Billing Year.[9] Duke Energy Carolinas shall post such Estimated Billing Rates on its website via link to the public portion of its OASIS and shall submit such Estimated Billing Rates and supporting information to the FERC in an informational filing.[10] If the date for making such posting should fall on a weekend or a holiday recognized by the FERC, then the posting shall be made on the next

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7 Excluding any component of Estimated Billing Rates which is due to the inclusion of the True-Up Amount With Interest from the preceding year in the ATRR.

8 For the calculation of the first True-Up Amount, if the Formula Rates were not in effect for the entire preceding calendar year, then the calculation shall be performed for the part of the year for which the Formula Rates were in effect and all amounts shall be prorated as appropriate.

9 Except that the initial Billing Year shall commence on the date that the Formula Rate becomes effective and shall terminate on the immediately subsequent May 31.

10 For the initial year in which the Formula Rate is effective, Duke Energy Carolinas shall prepare and post the Estimated Billing Rates no later than fifteen days prior to date that the Formula Rate becomes effective.

business day. Estimated Billing Rates shall be based upon values determined in accordance with these Protocols and the following:

(i) for rate base components (other than prepayments) reflected in the ATRR, the end-of-year plant balances for the preceding calendar year;

(ii) for prepayments reflected in the ATRR, the average of the end-of-month balances over the 13 month period ending with the last month of the preceding calendar year; and

(iii) for expense components reflected in the ATRR, the actual historical expenses for the preceding calendar year.

The foregoing values shall be determined during the Annual Update process using as-recorded data; provided, however, that the values described in this subparagraph (i) will be adjusted for the True-Up With Interest as described in Section 2(h)(iii) above and may further be adjusted by Duke Energy Carolinas in its reasonable discretion for capital additions projected to be made during the Billing Year, such adjustment (if made) to be based on the projected total capital additions expenditures for that period. During the Billing Year, Duke Energy Carolinas shall bill and the Customers shall pay for transmission service based on the Estimated Billing Rates.

Section 3: Annual Review Procedures

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a) **Customer Meeting**. With the posting of the Annual Update, Duke Energy Carolinas shall provide notice to Customers that an open Customer meeting will be held, on a date specified in the notice that shall be no earlier than ten (10) business days from the date of posting of the Annual Update and no later than June 15, to discuss the Annual Update ("Customer Meeting"). Duke Energy Carolinas shall provide the opportunity for participation by telephone conference at this Customer Meeting. At the Customer Meeting, Duke Energy Carolinas shall provide

(i) an overview of the Annual Update, including, on an informal (*i.e.*, non-binding) basis, information about the updated inputs to the Formula Rate , and including, without limitation, a summary sheet that shows the expiring Estimated Billing Rates for transmission service in \$/MW-Month, the true-up of that rate, and an item-by-item description of the factors that contribute in any material way to the true-up of that rate, referencing the page and line of the Formula Rate template and associated dollar amount of the change and the rate impact of the change;

(ii) an opportunity to discuss the factors that contribute in any material way to the true-up of the rate;

b) **Preliminary Challenges**. Unless the period is extended with the written consent of Duke Energy Carolinas or is extended as provided for in section 3(e) of these

Protocols to resolve discovery disputes, a Customer shall have up to 120 days after the Publication Date ("Review Period") to review the calculations and to notify Duke Energy Carolinas in writing of:

(i) any challenge to the Annual Update (or any portion thereof) or the application of the Formula Rate, or

(ii) any specific challenge based on

(A) changes in the Fundamental Predicates reflected in items (i) through (v) as set forth in Section 1(d) above that may produce changes in the rates and charges produced from the application of the Formula Rate subsequent to such change; and/or

(B) the prudence of any costs included in the Annual Update.

A challenge raised on the basis of any of the foregoing grounds shall be referred to as a "Preliminary Challenge."

c) **Changes to Fundamental Predicates**. All change(s) to the Fundamental Predicates (other than through filings pursuant to Section 1(b) of these Protocols that update FERC Form 1 references and do not make substantive changes to the Formula Rate), subsequent to the date specified in Section 1(d), shall warrant a re-assessment of all of the elements of the Formula Rate that are affected by the change or changes in one or more Fundamental Predicates to ensure that the Formula Rate operates together to produce a just, reasonable and not unduly discriminatory or preferential Formula Rate. If there is a change to the Fundamental Predicates that requires a change to the Formula Rate to ensure that the Formula Rate operates to produce a just, reasonable and not unduly discriminatory or preferential Formula Rate, Duke Energy Carolinas will effectuate the change in the Formula Rate through a filing under Federal Power Act Section 205.

d) **Information Requests**. Unless such period is extended with the written consent of Duke Energy Carolinas or is extended as provided for in Section 3.e of these Protocols to resolve discovery disputes, any Customer shall have up to 90 days after each annual Publication Date to serve reasonable information requests on Duke Energy Carolinas. Such information requests shall be limited to what is reasonably necessary to determine

(i) whether Duke Energy Carolinas has calculated the Annual Update under review properly and in accordance with these Protocols;

(ii) whether Duke Energy Carolinas has applied the Formula Rate according to its terms, including the procedures in these Protocols;

(iii) whether the costs included in the Annual Update are properly accounted for (*e.g.*, recordable and recorded in the appropriate accounts) under FERC's USoA and otherwise consistent with Duke Energy Carolinas' accounting policies, practices, or procedures;

(iv) whether the costs are prudent; and

v) whether accounting changes or changes in the USoA or in the requirements and contents of the FERC Form No. 1 have affected application of the Formula Rate, and if so, whether the effect of those changes has been properly reflected in the Annual Update.

Such information requests shall not solicit information that solely relates to inputs that are Stated Values or cost allocation methods that have been determined by any final order by the FERC pursuant to FPA Sections 205, 206 or 306 with respect to Duke Energy Carolinas (including an order approving a settlement), except that such information requests shall be permitted if they seek to determine whether there have been material changed circumstances and to confirm consistency with the applicable order (and associated settlement, if any).

e) **Response Period**. Duke Energy Carolinas shall respond to information requests pertaining to the Annual Update within 15 business days of receipt of such requests unless impracticable, in which case, Duke Energy Carolinas shall, within such 15-day period, notify the party requesting information of the delay and provide an estimated date for the responses.

f) **Discovery Master**. To the extent Duke Energy Carolinas and any Customer are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, Duke Energy Carolinas or any Customer may petition the FERC to appoint an Administrative Law Judge as a discovery master. The discovery master shall have the power to issue binding orders to resolve discovery disputes and compel the production of discovery, as appropriate, in accordance with the Annual Review Procedures and consistent with the FERC's discovery rules; provided, however, that the Review Period set forth in Section 3.b of these Protocols and the period for discovery provided for in Section 3.d of these Protocols will be tolled during the pendency of any discovery dispute submitted to the discovery master, such tolling period to end ten business days after the date on which the order issued by the discovery master provides for resolution of the discovery dispute pursuant to this subsection.

g) **Use of Information**. All information and correspondence produced pursuant to these Protocols may be included in any Preliminary or Formal Challenge, in any other proceeding concerning the Formula Rate initiated at FERC pursuant to the FPA, or in any proceeding before a U.S. Court of Appeals to review a FERC decision.

h) **No Implied Limitations on FPA Rights; Standard of Review**. Except as specifically set forth in these Protocols, these Protocols in no way limit the rights of Duke Energy Carolinas or any Customer to initiate a proceeding at FERC at any time with respect to the Formula Rate, any Stated Value or any Annual Update consistent with the party's full rights under the Federal Power Act, including Sections 205, 206 and 306, and FERC's regulations. Except with respect to proceedings to modify any provisions of the Formula Rate which reflect Specific

Settlement Provisions[11], in any proceeding initiated *sua sponte* by the Commission or by a party or parties (other than Duke Energy Carolinas) seeking to modify any portion of the Formula Rate or Stated Value in any respect, the party seeking such modification shall bear the burden of proving that the portion of the Formula Rate or Stated Value that the party seeks to change is no longer just and reasonable without such modification and that the proposed modification is just and reasonable. Except with respect to proceedings to modify any provisions of the Formula Rate which reflect any Specific Settlement Provisions, in any proceeding initiated by Duke Energy Carolinas seeking to modify any portion of the Formula Rate or Stated Value in any respect, Duke Energy Carolinas shall bear the burden of proving that the proposed modification is just and reasonable. In any proceeding seeking to modify any provisions of the Formula Rate which reflect any Specific Settlement Provisions, the initiating party shall bear the burden of proving that the application of such provisions, absent the proposed modification, seriously harms the public interest as set forth in *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish, Washington,* 128 S. Ct. 2733, 171 L. Ed. 2d 607 (2008); *see also United Gas Pipeline Co. v. Mobile Gas Service Corp.*, 350 U.S. 348 (1956). Notwithstanding the foregoing, Duke shall make a Section 205 filing to terminate recovery of GridSouth costs and eliminate the Stated Value for GridSouth from the Formula Rate effective as of the last day of the applicable amortization period (*i.e.*, the period underlying the annual amortization amounts that are the initial Stated Values for this item), and such filing by Duke Energy Carolinas shall be subject to the just and reasonable standard of review.

Section 4: Resolution of Challenges

a) **Challenge in Writing**. A party wishing to raise a Preliminary Challenge with Duke Energy Carolinas (hereinafter, "Challenging Party") shall submit its challenge in writing to Duke Energy Carolinas.

b) **Duke Questions**. Duke Energy Carolinas shall have the right to ask the Challenging Party questions about the Preliminary Challenge. Such questions shall be submitted to the Challenging Party within ten (10) days after receiving the Preliminary Challenge, and responses shall be due ten (10) days after that.

c) **Response to Challenge**. Within fifteen (15) days after receiving such Preliminary Challenge or after receiving responses to questions pursuant to Section 4.b, Duke Energy Carolinas shall provide a written response to the Challenging Party. Such written response shall state whether Duke Energy Carolinas agrees or disagrees with the position raised by the Challenging Party, and what, if any, modifications to the Annual Update Duke Energy Carolina agrees to make in order to resolve the Preliminary Challenge. If Duke Energy Carolinas disagrees with the Preliminary Challenge, it shall include in its written response a statement of its position and any documentation that Duke Energy Carolinas believes supports its position.

[11] "Specific Settlement Provisions" shall mean the provisions of Article II of the Settlement Agreement which is filed in this proceeding.

d) **Customer Questions**. The Challenging Party shall have the right to ask Duke Energy Carolinas questions about its response provided pursuant to Section 4.c. Such questions shall be submitted to Duke Energy Carolinas within ten (10) days after receiving Duke's response to the Preliminary Challenge, and Duke's responses to those questions shall be due ten (10) days after that.

e) **Formal Challenge**. If Duke Energy Carolinas and a Challenging Party have not resolved a Preliminary Challenge to an Annual Update within 30 days after receipt of Duke Energy Carolinas' written response to the Preliminary Challenge or, if applicable, its responses to questions regarding its written response, the Challenging Party shall have the right to make a Formal Challenge with the FERC, which shall be served on Duke Energy Carolinas by electronic service on the date of such filing. However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 3 and 4 if the FERC already has initiated *sua sponte* a proceeding to consider the Annual Update.

f) **Burden of Proof**. In any proceeding initiated by the FERC concerning the Annual Update or in response to a Formal Challenge, Duke Energy Carolinas shall bear the burden of proving that it has properly calculated the challenged Annual Update and reasonably applied the terms of the Formula Rate for that year's Annual Update (including, but not limited to, consistency with the Fundamental Predicates); and of demonstrating that it has reasonably adopted and applied a change in Duke Energy Carolinas' accounting policies, practices or procedures; provided, however, that challenges to the prudency of costs shall be subject to the then-existing criteria and evidentiary burdens established in FERC policy applicable to prudence challenges in a Section 205 context.

g) **No Implied Limitation on FPA Rights**. Nothing herein shall be deemed to limit in any way (i) the right of Duke Energy Carolinas to file unilaterally, pursuant to FPA Section 205 and FERC's regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, Stated Values or to replace the Formula Rate with a stated rate; or (ii) the right of any Customer to request changes to the Formula Rate pursuant to FPA Section 206 and FERC's regulations thereunder.

h) **Adjustments to True-Up Amount and Estimated Billing Rates**. The initiation of a Preliminary Challenge or a Formal Challenge will not obligate Duke Energy Carolinas to adjust either the True-Up Amount or the Estimated Billing Rates. However, resolution of Preliminary or Formal Challenges may necessitate adjustments to the Formula Rate input data for the applicable Annual Update as set forth in Section 5(c).

i) **Formula Rate Changes Due to Changes in Fundamental Predicates**. If the application of the Formula Rate in light of any change to any of the Fundamental Predicates is found by FERC to be unjust, unreasonable, and/or unduly discriminatory or preferential, then the calculation of costs incurred during the year then under review, and any subsequent years, and associated True-Ups, shall not include such change, and shall include any such other remedy prescribed by FERC, including adjustments to the Formula Rate to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

Section 5: Corrections and Changes Pursuant to Annual Update Process

a) **Corrections to Annual Update**. If Duke Energy Carolinas determines or concedes that corrections to the Annual Update are appropriate, Duke Energy Carolinas shall promptly notify the Customers, file a correction to the Annual Update with FERC as an amended informational filing and post the correction on its OASIS.

b) **Review of Corrections**. Interested parties shall have the right to review and challenge the corrections. The performance dates under Sections 3 and 4 of these Protocols shall apply to review and challenge, except that these dates shall run from the posting date(s) for each of the corrections. The scope of review and challenge shall be limited to the portions of the Annual Update affected by the corrections.

c) **Adjustments to True-Up Amount and Estimated Billing Rates**. Any increase or decrease in the ATRR that results from one of the following events shall be reflected as an increase or reduction in the True-Up Amount and the Estimated Billing Rates (with applicable interest) commencing within thirty (30) days following a determination of the need for the adjustment or such later date as FERC may direct: (i) revisions to Duke Energy Carolinas' accounting and reporting of its costs to correct errors; and/or (ii) revisions to Duke Energy Carolinas' accounting and reporting of its costs to reflect the resolution of Preliminary Challenges or Formal Challenges by FERC order or by settlement or as the result of any FERC proceeding to consider the Annual Update.

d) **Survival of Protocols**. In the event Duke Energy Carolinas seeks to replace the Formula Rate with stated rates in a Section 205 filing, the provisions of these Protocols, including the obligation to true-up the ATRR, shall remain applicable notwithstanding FERC's acceptance of the stated rate filing for as long as necessary to ensure that any over/under recoveries required to accommodate the final True-Up for the last effective Billing Year under the Formula Rate can be refunded/surcharged.

e) **Service of 205 Actions**. Duke Energy Carolinas shall electronically serve any filing, including unlocked and non-read only (*i.e.*, manipulable and with the formulas intact) versions of any supporting spreadsheets, in which Duke Energy Carolinas seeks to modify the Formula Rate, or to adopt a stated rate, on all Customers and on all affected state commissions.

RATE IMPLEMENTATION TIMELINE

2011	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		
	File Estimated Billing Rates May 15					**Begin billing June 1**								
						Billing Year 2011-2012								
						Estimated Billing Rates = Estimated based on 2010 calendar year actuals + estimated 2011 capital additions								
2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		
	File ATRR & Estimated Billing Rates May 15					**Begin billing June 1**								
	Billing Year 2011-2012					**Billing Year 2012-2013**								
						Estimated Billing Rates = Estimated based on 2011 calendar year actuals + estimated 2012 capital additions								
						True-up Adjustment = Actual 2011 calendar year ATRR compared to actual amount collected from customers, spread evenly over 12 month period								
2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		
	File ATRR & Estimated Billing Rates May 15					**Begin billing June 1**								
	Billing Year 2012-2013					**Billing Year 2013-2014**								
						Estimated Billing Rates = Estimated based on 2012 calendar year actuals + estimated 2013 capital additions								
						True-up Adjustment = Actual 2012 calendar year ATRR compared to actual amount collected from customers, spread evenly over 12 month period								

EXHIBIT B TO SCHEDULE 10-B
DUKE ENERGY CAROLINAS FORMULA RATE TEMPLATE

Duke Energy Carolinas, LLC
OATT Transmission Rate Formula Template Using Form 1-Data
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Summary of Rates

Line		Reference	OATT Amount
1	**Gross Revenue Requirement**	Page 3, Line 33	$ -
	Revenue Credits:		
2	Acct 454 - Allocable to Transmission	Attachment G	$ -
3	Acct 456.1 - NF+STF x/Ancillaries, GridSouth	Attachment I	$ -
4	**Total Revenue Credits**		$ -
5	**Interest Disbursed w/ Network Prepay Refunds**	Attachment J	$ -
6	**Revenue Requirement - Customer Owned Facilities**		$ -
7	**GridSouth System Level for Wholesale Amount (Note N)**	Attachment K	$ -
8	**Transmission Incentives**	Note T	$ -
9	**Total Transmission Revenue Requirement**	(Line 1 - Line 4 + Line 5 + Line 6 + Line 7+ Line 8)	$ -
10	**Transmission Loss Factor**	(1- Loss factor stated in OATT)	0%
11	**Revenue Tax Factor**	Note U	1
12	**Annual Transmission Revenue Requirement**	(Line 9 / Line 10)/Line 11	$ -
13	**Divisor - 12 Month Average Transmission Peak**	Attachment K, Line 10 Total KW/12	-
14	**PTP Trans. Rev Req't Rate $/kW - Year**	Line 12 / Line 13 / 1000	$ -
15	**PTP Demand Rate $/kW - Month**	Line 14/12	$ -
16	**Weekly Firm/Non-Firm PTP Rate $/kW - Week**	Line 14/ 52 weeks	$ -
	Daily Firm/Non-Firm PTP Rates ($/kW):		
17	On-Peak Days	Line 16/ 5 days	$ -
18	Off-Peak Days	Line 16 / 7 days	$ -
	Non-Firm Hourly PTP Rates ($/kW):		
19	On-Peak Days	Line 17 / 16hrs	$ -
20	Off-Peak Days	Line 18/ 24hrs	$ -

Duke Energy Carolinas, LLC
OATT Transmission Rate Formula Template Using Form 1-Data
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Development of Rate Base

Line	Rate Base:	Reference	Beginning Balance	Ending Balance	Average	Allocator		OATT Amount
	Gross Plant In Service: (Note A and I)							
1	Production Plant	204.46.b, 205.46.g	$ -	$ -	$ -	N/A		
1a	Production Contra AFUDC	Attachment P	$ -	$ -	$ -	N/A		
1b	Eliminate Production ARO	205.15.g, 205.24.g, 205.34.g, 205.44.g	$ -	$ -	$ -	N/A		
1c	Electric Plant Purchased (Sold)	206.101.b, 207.101.g	$ -	$ -	$ -	N/A		
2	Transmission Plant	207.58.b, 207.58.g	$ -	$ -	$ -	TP	-	$ -
2a	Transmission Contra AFUDC	Attachment P	$ -	$ -	$ -	TP	-	$ -
3	Distribution Plant	206.75.b, 207.75.g	$ -	$ -	$ -	N/A		
4	General Plant	206.99.b, 207.99.g	$ -	$ -	$ -	OATT Labor	-	$ -
4a	Eliminate General ARO	206.98.b, 207.98.g	$ -	$ -	$ -	OATT Labor	-	$ -
4b	Eliminate System Operating Center (SOC)	Schedule 1 Line 1	$ -	$ -	$ -	OATT Labor	-	$ -
5	Intangible Plant	204.5.b, 205.5.g	$ -	$ -	$ -		Attachment L	$ -
6	**Total Gross Plant**		$ -	$ -	$ -	GP=	-	$ -
	Accumulated Depreciation							
7	Production Depr. Reserve	219.20-24.b	$ -	$ -	$ -	N/A		
7a	Production Contra AFUDC	Attachment P	$ -	$ -	$ -	N/A		
7b	Eliminate Production ARO Accum Depreciation	Attachment P (Note W)	$ -	$ -	$ -	N/A		
8	Transmission Depr. Reserve	219.25.b	$ -	$ -	$ -	TP	-	$ -
8a	Transmission Contra AFUDC	Attachment P	$ -	$ -	$ -	TP	-	$ -
9	Distribution Depr. Reserve	219.26.b	$ -	$ -	$ -	N/A		
10	General Depr. Reserve	219.28.b	$ -	$ -	$ -	OATT Labor	-	$ -
10a	Eliminate General ARO Accum Depreciation	Attachment P (Note W)	$ -	$ -	$ -	OATT Labor	-	$ -
10b	Eliminate SOC Accum Depreciation	Line 10 * Schedule 1 Line 32	$ -	$ -	$ -	OATT Labor	-	$ -
11	Intangible Depr. Reserve	200.21.c	$ -	$ -	$ -		Attachment M	$ -
12	**Total Accumulated Depr.**		$ -	$ -	$ -			$ -
	Net Plant in Service							
13	Net Production Plant	Line (1:1c) - Line (7:7b)	$ -	$ -	$ -			$ -
14	Net Transmission Plant	Line (2:2a) - Line (8:8a)	$ -	$ -	$ -			$ -
15	Net Distribution Plant	Line 3 - Line 9	$ -	$ -	$ -			$ -
16	Net General Plant	Line (4:4b) - Line (10:10b)	$ -	$ -	$ -			$ -
17	Net Intangible Plant	Line 5 - Line 11	$ -	$ -	$ -			$ -
18	Total Net Plant		$ -	$ -	$ -	NP=	-	$ -
	Adjustments to Rate Base - Deferred Taxes							
19	ADIT - 190	234.18.b, 234.18.c	$ -	$ -	$ -		Attachment A	$ -
20	ADIT - 282 (Note O)	274.9.b, 275.9.k	$ -	$ -	$ -		Attachment B	$ -
21	ADIT - 283	276.19.b, 277.19.k	$ -	$ -	$ -		Attachment C	$ -
22	**Total Deferred Tax Adjustments**		$ -	$ -	$ -			$ -
	Adjustments to Rate Base							
23	Accum Provision for P&B (182.3 & 228.3)	Attachment D and Attachment E	$ -	$ -	$ -	OATT Labor	-	$ -
24	Pension Cost Adj (182.3 & 253.047)	Attachment D and Attachment F	$ -	$ -	$ -	OATT Labor	-	$ -
25	General Liability claim (182.3)	232.44.b, 232.44.f	$ -	$ -	$ -			$ -
26	Accum Provision for I&D (228.2)	112.28.c	$ -	$ -	$ -			$ -
27	**Net Rate Base Adjustments**		$ -	$ -	$ -			$ -
28	**Plant Held For Future Use**	Note B	$ -	$ -	$ -			$ -
29	**CWIP for Transmission Projects**	Note P	$ -	$ -	$ -		50.000000	$ -
30	**Unamortized Abandoned Plant**	Note Q	$ -	$ -	$ -	TP	-	$ -
	Rate Base Adjustment - Network Upgrade Prepayment Balances (Note J)							
31	Balance - Network Prepayments	Attachment J	$ -	$ -	$ -	D/A	(1.000000)	$ -
32	Accrued Interest Balance	Attachment J	$ -	$ -	$ -	D/A	1.000000	$ -
32a	Reversal of Anson AFUDC per Settlement	Attachment J	$ -	$ -	$ -	D/A	1.000000	$ -
33	**Total Network Upgrade Prepayment Adjustments**		$ -	$ -	$ -			$ -
	Working Capital							
34	Cash Working Captial (1/8 O&M)	Page 3, Line 14 /8	$ -	$ -	$ -	TP	-	$ -
35	Materials & Supplies - Transmission	227.8.c	$ -	$ -	$ -	TP	-	$ -
36	Materials & Supplies - Stores Expense	227.16.c	$ -	$ -	$ -	OATT Labor	-	$ -
37	Prepayments	13 Month Average Balance used	$ -	$ -	$ -	GP	-	$ -
38	**Total Working Capital**		$ -	$ -	$ -			$ -
39	**Rate Base (Sum of lines 18, 22, 27, 28, 29, 30, 33 and 38)**		$ -	$ -	$ -			$ -

Duke Energy Carolinas, LLC
OATT Transmission Rate Formula Template Using Form 1-Data
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Development of Revenue Requirement

Line	Expenses	Reference	Ending Balance	Allocator		OATT Amount
	O&M Expense					
1	TOTAL Transmission Expenses	321.112.b	$ -			
2	Less Account 561.1, 561.2, 561.3, 561.4 & 565	321.85.b:321.88.b; 321.96.b	$ -			
2a	Plus Labor Associated with Transmission Control Center (TCC) booked in above accounts	Schedule 1, Line 8a	$ -			
3	Net Transmission O&M		$ -	TP	0.000000	$ -
4	Total Admin & General Expenses (less PBOP expense)	323.197.b - Line 13	$ -			
5	Less (924) Property Insurance	323.185.b	$ -			
6	Less (928) Regulatory Commission Expense	323.189.b	$ -			
7	Less (930.1) General Advertising Expenses	323.191.b	$ -			
8	Less Industry Dues, R&D and Nuc Assoc Exp	335.1-3.b	$ -			
9	Net Labor Related A&G		$ -	OATT Labor	0.000000	$ -
10	(924) Property Insurance	323.185.b	$ -	GP	0.000000	$ -
10a	Less Property Insurance allocated to SOC	Line 10 * Schedule 1 Line 35	$ -	GP	0.000000	$ -
11	Trans. Related Regulatory Expense	350.11.b	$ -	TP	0.000000	$ -
12	Trans. Related Advertising Exp.		$ -	D/A		
13	PBOP Expense	Note L	$ -	OATT Labor	0.000000	$ -
13a	Conforming Adj. -2009 PBOP Expense	Note L	$ -	OATT Labor	0.000000	$ -
14	**Total O&M (Sum of lines 3, 9, and 10 thru 13)**					$ -
	Depreciation Expense					
15	Transmission Depr. Expense	336.7.f	$ -	TP	0.000000	$ -
15a	Add Transmission Contra AFUDC	Attachment P	$ -	TP	0.000000	$ -
15b	Amortization of Abandoned Plant	Note Q	$ -	TP	0.000000	$ -
16	General Depr. Expense	336.10.f	$ -	OATT Labor	0.000000	$ -
16a	Less General Depreciation allocated to SOC	Line 16 * Schedule 1 Line 35	$ -	OATT Labor	0.000000	$ -
17	Intangible Amortization	336.1.f	$ -			$ -
18	Extraordinary Property Loss	Note R	$ -	TP	0.000000	$ -
19	**Total Depreciation**		$ -			$ -
	Taxes Other Than Income (Note C)					
20	Labor Related	263.i, 263.1.i	$ -	OATT Labor	0.000000	$ -
21	Property Related	263.i - Note D	$ -	GP	0.000000	$ -
21a	Less Property Related allocated to SOC	Line 20 * Schedule 1 Line 32	$ -	GP	0.000000	$ -
22	**Total Other Taxes**		$ -			$ -
	Return					
23	Rate Base (Page 2, Line 39) * Rate of Return (Page 4, Line 24)					$ -
	Income Taxes					
24	NC/SC Composite	Note E	0.00%			
25	Federal		0.00%			
26	Composite T = State + (Federal *(1-State))		0.00%			
27	Tax Rev. Req't Factor = T/(1-T) * (1 - Wtd.Debt.Cost/R)		0.00%			
28	ITC Gross Up Factor = 1 / (1-T)		1.000			
29	Amortized ITC (Negative)	266.8.f	$ -			
30	Income Taxes Calculated (Line 23 * Line 27)		$ -			$ -
31	ITC Adjustment (Line 28 * Line 29)		$ -	NP	0.000000	$ -
32	**Total Income Taxes**					$ -
33	**TOTAL REVENUE REQUIREMENT (Sum of Lines 14, 19, 22, 23, and 32)**					$ -

Duke Energy Carolinas, LLC
OATT Transmission Rate Formula Template Using Form 1-Data
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Supporting Allocation Factor and Return Calculations

Line		Reference		Total
	Transmission Plant Included in OATT Rate			
1	Total Transmission Plant	Page 2, Lines 2 & 2a		$ -
2	Less: Gen. Step-up Transformers and Interconnection Facilities	Note F		$ -
3	Less: Transmission under 44KV	423.3.16.l		$ -
3a	Less: New Radial Lines	Note X		$ -
4	Trans Plant for OATT Rate			$ -
5	**TP Allocator (Line 4/Line1)**	Note G		0.0000%
	Labor Allocation Factor			
6	Total Direct Payroll - O&M Labor	355.65.b, Note H		$ -
7	A&G Labor	354.27.b, Note H		$ -
8	Adjusted Labor	(Line 6 - Line 7)		$ -
9	Transmission O&M Labor	354.21.b		$ -
10	**Trans Labor Factor (Line 9/Line 8)**			0.00000%
11	**OATT Labor Allocator (Line 5*Line 10)**			0.00000%
	Return and Capitalization:			
12	Long Term Interest Expense	117.62-67.c		$ -
13	Net Long Term Interest Expense			$ -
14	Long Term Debt	112.24.c		$ -
15	Less Loss on Reacquired Debt	111.81.c		$ -
16	Plus Gain on Reacquired Debt	113.61.c		$ -
17	Net Long Term Debt			$ -
	Common Stock Development			
18	Proprietary Capital	112.16.c		$ -
19	Less Account 216.1	112.12.c		$ -
20	Common Stock			$ -
21	**Total Capitalization (Sum Lines 17 and 20)**			**$ -**
	Summary Cap Structure (Note S)	Weight	Cost	Weighted Cost
22	Long Term Debt	0.00%	0.00%	0.00%
23	Common Stock (Note V)	0.00%	10.20%	0.00%
24	**Overall Return:**			**0.00%**

NOTES:

(A) Contra AFUDC adjustments may relate to inclusion of CWIP in rate base for retail jurisdictions but not wholesale, or inclusion of CWIP in rate base for wholesale jurisdiction but not retail.
(B) FERC Form 1 page 214 excluding non-transmission related items
(C) Excludes all income and gross receipts taxes. Labor related other taxes include FICA and unemployment taxes. Property related taxes include county and local property, highway use, and intangible taxes.
(D) Includes percentage of SC Franchise tax that is related to property
(E) Determined by annual apportionment factors provided by Tax Department
(F) Analysis of Company records of Interconnection facilities built after March 15, 2000.
(G) The allocator "TP" is the percent of gross transmission plant that is OATT related, i.e., after removal of generator step-up and interconnection investments. It also serves as the basis for deriving the OATT transmission related labor from the Form 1 reported values.
(H) Excludes from the payroll reported on Form 1 page 354 amounts for which Duke Energy Carolinas is reimbursed by the Catawba Joint Owners
(I) Amounts in Gross Plant that are not provided by investor funds are excluded. These include FAS 109 and ARO
(J) Network upgrade balance - prepayments is a reduction to rate base, accrued interest balance is an increase to rate base and Anson AFUDC reversal is a reduction.
(K) Duke Energy Carolinas will retain 50% of net revenues consistent with *Pacific Gas and Electric Company, 90 FERC ¶ 61,314.*
(L) PBOP Expense stated at the 2009 expense level and will only be modified with a full section 205 filing at FERC.
(M) The wholesale allocation factor for GridSouth will be set at the 2009 Transmission peak.
(N) Beginning June 1, 2018 and each year thereafter, the value of the GridSouth amortization at Attachment Kline 4 will be zero.
(O) The Company only functionalizes Account 282 during annual tax return process. Will use most recent annual tax return reports to allocate account balance to correct functions.
(P) DEC must make a full section 205 filing at FERC before inputting or changing amounts associated with CWIP
(Q) DEC must make a full section 205 filing at FERC before inputting or changing amounts associated with abandoned plant
(R) DEC must make a full section 205 filing at FERC before inputting or changing amounts associated with extraordinary property loss
(S) ROE will be supported in the original filing and no change in ROE will be made absent a full section 205 filing at FERC. Depreciation rates shown are fixed until changed as the result of a 205 filing at FERC.
(T) DEC must make the appropriate filing at FERC before inputting or changing amounts associated with Transmission Incentives
(U) Revenue Tax Rate shall equal 1.0 minus the applicable revenue or gross receipts tax rate(s) to which Duke is subject for the revenue or gross receipts that Duke receives under this agreement. This is subject to change upon the filing of a full section 205 rate case.
(V) The equity component of the capital structure will be capped at the 2009 year end level of 52.4%. A full section 205 filing at FERC is required to change this stated value.
(W) Account 108.499 from general ledger
(X) "New Radial Facilities" are lines and facilites that (1) are radially constructed, (2) are placed in service after the effective date of this formula rate, and (3) do not meet the Commission's standard for treating the lines and facilities as integrated with Duke Energy Carolinas' transmission system. New Radial Facilities built for or by a Customer will be presumed to provide benefits to Duke Energy Carolinas' integrated network if such facilities would be treated as part of Duke Energy Carolinas' integrated network if built exclusively to provide service to Duke Energy Carolinas' retail customers.

Duke Energy Carolinas, LLC
OATT Transmission Rate Formula Template Using Form 1-Data
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Schedule 1 Duke Energy Carolinas Revenue Requirements

Line		Reference	Beginning Balance	Ending Balance	Average Balance
1	System Operating Center (SOC) Gross Plant	Attachment S1	-	-	$ -
2	SOC Intangible Plant	Attachment L	-	-	$ -
3	Less: SOC Accumulated Depreciation Gross Plant	Page 2, Line 10b	-	-	$ -
4	Less: SOC Accumulated Depreciation Intangible Plant	Attachment M	-	-	$ -
5	**Total Net SOC**	Sum (Line 1: Line 4)	-	-	-
6	Working Capital	1/8 * [Line 13 - Line 9-Line 10-Line 12]			-
7	**Total Rate Base**	Line 5 + Line 6			-
8	Total Load Dispatch & Scheduling Expense- Accounts 561.1 - 561.4	321.85.b:321.88.b			-
8a	Less: Costs Associated with TCC	Attachment Q			-
8b	Less: NERC/SERC Fees related to Retail Load	Attachment Q			-
8c	Less: Scheduling Fees Associated with Off-system Sales	Attachment Q			-
9	Depreciation Expense on SOC	Page 3, Line 16 a			-
10	Amortization Expense on SOC	Attachment N			-
11	Property Insurance on SOC	Page 3, Line 10a			-
12	Property Related Taxes Other than Income on SOC	Page 3, Line 20a			-
13	Total Expenses	Sum (Line 8: Line 12)			-
14	**Return on Rate Base**	Line 7 * Page 4, Line 24			$ -
15	**Income Taxes**	Line 14 * Page 3, 5 Line 27			$ -
16	Total Revenue Requirement	Sum Line 13 + Line 14 + Line 15			$ -
17	Less: Non- Firm PTP Service Credit (prior year Sched 1 revenue from non-firm PTP transactions)	Attachment I			$ -
18	**Transmission Loss Factor**	(1- Loss factor stated in OATT)			0%
19	**Schedule 1 Annual Revenue Requirement**	(Line 16 + Line 17) / Line 18			$ -
20	12 Month Average Transmission Peak	Page 1, Line 14			-
21	Annual Point to Point Rate $/kW/Year	(Line 19 / Line 20 /1000)			$ -
22	Annual Point to Point Rate $/kW/mth	(Line 21/ 12)			$ -
23	Annual Point to Point Rate $/kW/Week	(Line 21/ 52)			$ -
24	Annual Point to Point Rate $/kW/Day	(Line 21/ 365)			$ -
25	Annual Point to Point Rate $/kW/Hour	(Line 21/ 8760)			$ -
	Daily Firm/Non-Firm PTP Rates ($/kW):				
26	On-Peak Days	Line 23 / 5 days			$ -
27	Off-Peak Days	Line 23 / 7 days			$ -
	Non-Firm Hourly PTP Rates ($/kW):				
28	On-Peak Days	Line 26/ 16hrs			$ -
29	Off-Peak Days	Line 27/ 24hrs			$ -
	SOC Allocation Factor Calculation				
30	SOC Gross Plant	Line 1			-
31	Gross General Plant	Rate Page 2 Line 4			-
32	SOC GP Allocation Factor	Line 30 / Line 31			0.0000%
33	SOC Gross Plant	Line 1			-
34	System Gross Plant (Including SOC)	Rate Page 2 Line 6 - Line 4b			-
35	SOC System Allocation Factor	Line 33 / Line 34			0.0000%

Attachment A

Duke Energy Carolinas, LLC
Transmission Rate Formula Support
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Deferred Income Tax Balances - GL Account 190

	GL Balance 12/31/2008 Dr(Cr)	GL Balance 12/31/2009 Dr(Cr)	Average Balance	Allocation Factor		OATT Amount
Amounts Not Allocated to Transmission	$ -	$ -	$ -	Other	0.000000	$ -
123R stock option	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Employee Benefits	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Environmental	$ -	$ -	$ -	NP	0.000000	$ -
FAS 112	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Hedging	$ -	$ -	$ -	NP	0.000000	$ -
OPEB	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Original Issue Discount	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Phantom Stk Awards	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Prepaid Insurance	$ -	$ -	$ -	OATT Labor	0.000000	$ -
R & D Tax Credit	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Severance Accrual	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Surplus Inventory Write-off	$ -	$ -	$ -	NP	0.000000	$ -
Surplus Inventory Write-off - Current	$ -	$ -	$ -	NP	0.000000	$ -
Total GL Account 190	**$ -**	**$ -**	**$ -**			**$ -**

Duke Energy Carolinas, LLC
Transmission Rate Formula Support

Deferred Income Tax Balances - GL Account 190 from Parent Company books

	GL Balance 12/31/2008 Dr(Cr)	GL Balance 12/31/2009 Dr(Cr)	Average Balance	Allocation Factor		OATT Amount
FAS 112	$ -	$ -	$ -	OATT Labor	0.00000	$ -
OPEB	$ -	$ -	$ -	OATT Labor	0.00000	$ -
Total GL Account 190 - Parent Company	**$ -**	**$ -**	**$ -**			**$ -**

Duke Energy Carolinas, LLC
Transmission Rate Formula Support
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Deferred Income Tax Balances - GL Account 282

Attachment B

	GL Balance 12/31/2008 Dr(Cr)	GL Balance 12/31/2009 Dr(Cr)	Average Balance	Allocation Factor		OATT Amount
PP&E - Production & Distribution	$ -	$ -	$ -	Production	0.000000	$ -
PP&E - Transmission	$ -	$ -	$ -	TP	0.000000	$ -
PP&E - General	$ -	$ -	$ -	OATT Labor	0.000000	$ -
PP&E - Intangible	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Total GL Account 282	**$ -**	**$ -**	**$ -**			**$ -**

Attachment C

Duke Energy Carolinas, LLC
Transmission Rate Formula Support
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Deferred Income Tax Balances - GL Account 283

	GL Balance 12/31/2008 Dr(Cr)	GL Balance 12/31/2009 Dr(Cr)	Average Balance	Allocation Factor		OATT Amount
Amounts Not Allocated to Transmission	$ -	$ -	$ -	Other	0.000000	$ -
Auction Rate securities	$ -	$ -	$ -	NP	0.000000	$ -
Bond Loss Amoritization	$ -	$ -	$ -	NP	0.000000	$ -
FAS 87 - employee qualified plan	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Prepaid Insurance	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Self Insurance	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Total GL Account 283	**-**	**$ -**	**$ -**			**$ -**

Duke Energy Carolinas, LLC
Transmission Rate Formula Support

Deferred Income Tax Balances - GL Account 283 (Per Parent Company's books for PEC)

	GL Balance 12/31/2008 Dr(Cr)	GL Balance 12/31/2009 Dr(Cr)	Average Balance	Allocation Factor		OATT Amount
FAS 87 - employee qualified plan	$ -	$ -	$ -	OATT Labor	0.000000	$ -
						$ -

Duke Energy Carolinas, LLC **Attachment D**
Transmission Rate Formula Support
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Other Deferred Debits - Acct 182 (Parent Company Books - Accounts Applicable to DEC)

	GL Balance 12/31/2008 Dr(Cr)	GL Balance 12/31/2009 Dr(Cr)	Average Balance	Allocation Factor		OATT Amount
OPEB	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Pension Cost Adj	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Total GL Account 182	**$ -**	**$ -**	**$ -**			**$ -**

Duke Energy Carolinas, LLC
Transmission Rate Formula Support

Other Regulatory Assets - Acct 182.3

	GL Balance 12/31/2008 Dr(Cr)	GL Balance 12/31/2009 Dr(Cr)	Average Balance	Allocation Factor		OATT Amount
Gridsouth Investment NC Retail	$ -	$ -	$ -	Other	0.000000	$ -
FAS 109	$ -	$ -	$ -	Other	0.000000	$ -
ARO	$ -	$ -	$ -	Other	0.000000	$ -
Vacation Accural	$ -	$ -	$ -	Other	0.000000	$ -
Nantahala Rewind	$ -	$ -	$ -	Production	0.000000	$ -
Thorpe Rewind	$ -	$ -	$ -	Production	0.000000	$ -
Section 124	$ -	$ -	$ -	Production	0.000000	$ -
NC DSM Regulatory Asset	$ -	$ -	$ -	Other	0.000000	$ -
Allen Environmental Compliance	$ -	$ -	$ -	Production	0.000000	$ -
Energy Efficiency Program Cost Deferral -SC	$ -	$ -	$ -	Production	0.000000	$ -
Energy Efficiency Program Cost Deferral -NC	$ -	$ -	$ -	Production	0.000000	$ -
Injuries and Damages - NP&L	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Total GL Account 182.3	**$ -**	**$ -**	**$ -**			**$ -**

Duke Energy Carolinas, LLC **Attachment E**
Transmission Rate Formula Support
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Accumulated Provisions for Injuries and Damages - GL Account 228.2

	GL Balance 12/31/2008 Dr(Cr)	GL Balance 12/31/2009 Dr(Cr)	Average Balance	Allocation Factor		OATT Amount
I and D Extraordinary	$ -	$ -	$ -	Other	0.000000	$ -
Environmental	$ -	$ -	$ -	NP	0.000000	$ -
Total GL Account 228.2	**$ -**	**$ -**	**$ -**			**$ -**

Duke Energy Carolinas, LLC
Transmission Rate Formula Support

Accumulated Provisions for Pensions and Benefits 228.3 (Parent Company Books - Accounts Applicable to DEC)

	GL Balance 12/31/2008 Dr(Cr)	GL Balance 12/31/2009 Dr(Cr)	Average Balance	Allocation Factor		OATT Amount
DPC OPEB FAS 106	$ -	$ -	$ -	OATT Labor	0.000000	$ -
DPC Pos EMP FAS 112	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Total GL Account 228.3	**$ -**	**$ -**	**$ -**			**$ -**

Duke Energy Carolinas, LLC
Transmission Rate Formula Support
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Other Deferred Debits 253.047 (Parent Company Books - Accounts Applicable to DEC)

Attachment F

	GL Balance 12/31/2008 Dr(Cr)	GL Balance 12/31/2009 Dr(Cr)	Average Balance	Allocation Factor		OATT Amount
Pension Cost Adj (ODC)	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Total GL Account 253.047	**$ -**	**$ -**	**$ -**			**$ -**

Duke Energy Carolinas, LLC **Attachment G**
Transmission Rate Formula Support
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Account 454 Reconciliation - Rents

North Carolina	Amount	Allocation Factor		OATT Amount
0454100 - Extra - Facilities	$ -	Company Records	0.370228	-
0454110 - Inter-connection-Cogeneration	$ -	Company Records	0.370228	-
0454200 - Pole and Line Attachments	$ -	Distribution	0.000000	-
0454300 - Tower Lease Revenues	$ -	Other, Attachment H	0.000000	-
0454400 - Other Electric Rents	$ -	OATT Labor	0.000000	-
0454500 - Leased Facilities Fee - Catawba	$ -	Distribution	0.000000	-
0454510 - Return and Dep - Catawba Gen Plt	$ -	OATT Labor	0.000000	-
Total GL Account 454	**$ -**			**$ -**

Duke Energy Carolinas, LLC **Attachment H**
Transmission Rate Formula Support
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Account 454.3 Reconciliation - Tower Lease Revenues

		Reference		
	Tower Lease Revenue Net Margin			
1	Revenues -0454300	Attachment G	$	-
2	Less: Direct Costs	Company Records	$	-
3	Net Revenues Before Taxes	Line 1 - Line 2	$	-
4	Composite Tax Rate	Page 3, Line 25		0.00%
5	After Tax Net Revenues	Line 3 * Line 4	$	-
6	TP Allocator	Page 4, Line 5		0.00%
7	Adjusted Net Revenues	Line 5 * Line 6	$	-
8	Revenue Sharing Percent	Note K		50%
9	Revenue Credit Amount	Line 7 * Line 9	$	-
	Tower Lease Revenue Reported in Formula			
10	Revenues -0454300		$	-
11	Less: Direct Costs	Line 2 * Page 4, Line 11	$	-
12	Net Revenues Before Taxes	Line 10 - Line 11	$	-
13	Composite Tax Rate	Page 3, Line 25		0.00%
14	After Tax Net Revenues	Line 12 - (Line 12*Line 13)	$	-
15	TP Allocator	Page 4, Line 5		0.00%
16	Adjusted Net Revenues	Line 14 * Line 15	$	-
17	Revenue Sharing Percent	Note K		50.00%
18	Revenue Credit Amount	Line 16 * Line 17	$	-
	Tower Lease Revenue Adjustment to Formula			
19	Revenue Credit	Line 9	$	-
20	Revenue Credit in other components of formula	Line 18	$	-
21	Adjusted Revenue Credit	Line 19 - Line 20	$	-

Duke Energy Carolinas, LLC
Transmission Rate Formula Support
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Transmission of Electricity for Others

Attachment I

Form 1 Reference	Payment by	Classification	Demand Charges	Energy Charges	Ancillary/Other Revenue	Total Revenue
	(Column (b))	(Column (d))	(Column (k))	(Column (l))	(Column (m))	(Column (n))
328, line 1	American Electric Power Company, Inc.	OS				-
328, line 2	American Electric Power Company, Inc.	SFP				-
328, line 3	Arclight Energy Marketing, LLC	OS				-
328, line 4	Bear Energy LP	OS				-
328, line 5	Calpine Power Services Company	OS				-
328, line 6	Calpine Power Services Company	SFP				-
328, line 7	Cargill-Alliant, LLC	OS				-
328, line 8	Cargill-Alliant, LLC	SFP				-
328, line 9	Cargill Power Marketer, LLC	LFP				-
328, line 10	Cargill Power Marketer, LLC	OS				-
328, line 11	Cargill Power Marketer, LLC	SFP				-
328, line 12	Carolina Power & Light Company	OS				-
328, line 13	Carolina Power & Light Company	SFP				-
328, line 14	Carolina Power & Light Company	LFP				-
328, line 15	Carolina Power & Light Company	LFP				-
328, line 16	Carolina Power & Light Company	LFP				-
328, line 17	Citigroup Energy Inc	OS				-
328, line 18	COBB Electric Membership Corporation	OS				-
328, line 19	COBB Electric Membership Corporation	SFP				-
328, line 20	ConocoPhillips, Inc.	OS				-
328, line 21	Constellation Commodities Energy Group	OS				-
328, line 22	Constellation Commodities Energy Group	SFP				-
328, line 23	Coral Power, LLC	OS				-
328, line 24	Eagle Energy Partners	OS				-
328, line 25	Eagle Energy Partners	SFP				-
328, line 26	Endure Energy, LLC	OS				-
328, line 27	Endure Energy, LLC	SFP				-
328, line 28	Florida Power Corporation	OS				-
328, line 29	Florida Power Corporation	SFP				-
328, line 30	Fortis Energy Marketing & Trading	OS				-
328, line 31	NextEra Energy Power Marketing, LLC	OS				-
328, line 32	J.P. Morgan Ventures Energy Corp.	OS				-
328, line 33	Merrill Lynch Commodities, Inc.	OS				-
328.1, line 1	Morgan Stanley Captial Group	OS				-
328.1, line 2	Morgan Stanley Captial Group	SFP				-
328.1, line 3	North Carolina Electric Member Corporation	LFP				-
328.1, line 4	North Carolina Electric Member Corporation	OS				-
328.1, line 5	North Carolina Electric Member Corporation	SFP				-
328.1, line 6	North Carolina Electric Member Corporation	LFP				-
328.1, line 7	North Carolina Electric Member Corporation	LFP				-
328.1, line 8	Nort Carolina Municpal Power Agency 1	OS				-
328.1, line 9	Nort Carolina Municpal Power Agency 1	SFP				-
328.1, line 10	Pwer Ex Corp	SFP				-
328.1, line 11	Rainbow Energy Marketing Corporation	OS				-
328.1, line 12	South Carolina Electric & Gas Company	OS				-
328.1, line 13	Southern Wholesale Energy	OS				-
328.1, line 14	Southern Wholesale Energy	SFP				-
328.1, line 15	Tenaska Power Services Co.	OS				-
328.1, line 16	Tennesee Valley Authority	OS				-
328.1, line 17	The Energy Authority	OS				-
328.1, line 18	The Energy Authority	SFP				-
328.1, line 19	Virginia Power Marketing	OS				-
328.1, line 20	Westar Energy	OS				-
328.1, line 21	Point to Point MWH(s) for all entries above					
328.1, line 22						
328.1, line 23	Blue Ridge Electric Memebership Corporation	LFP				-
328.1, line 24	City of Concord	LFP				-
328.1, line 25	City of Seneca	LFP				-
328.1, line 26	Town of Dallas	LFP				-
328.1, line 27	Town of Due West	LFP				-
328.1, line 28	Energy United Electric Membership	LFP				-
328.1, line 29	Town of Forest City	LFP				-
328.1, line 30	Greenwood Commissioners of Public Works	LFP				-
328.1, line 31	Haywood Electric Membership Corporation	LFP				-
328.1, line 32	City of King Mountain	LFP				-
328.1, line 33	Lockhart	LFP				-
328.2, line 1	New Horizon Electric Cooperative	LFP				-
328.2, line 2	North Carolina Electric Membership	LFP				-
328.2, line 3	North Carolina Municipal Power Agency 1	LFP				-
328.2, line 4	Piedmont Electric Memebership Corporation	LFP				-
328.2, line 5	Piedmont Municipal Power Agency	LFP				-
328.2, line 6	Town of Prosperity	LFP				-
328.2, line 7	Rutherford Electric Memebership Corporation	LFP				-
328.2, line 8	South Carolina Electric & Gas Company	LFP				-
328.2, line 9	South Carolina Public Service Authority					
328.2, line 10	- Network	LFP				-
328.2, line 11	Southeastern Power Administration	LFP				-
328.2, line 12	Western Carolina Energy, LLC	LFP				-
	Total Per Form 1		-	-	-	-
	Total SFP/OS Revenues		-	-	-	-
	Add: Duke Energy Carolinas Bulk Power Marketing					-
	Remove: LFP Transmission					-
	Remove: Ancillary Services and Loss Compensation excluding Schedule 1					-
	Remove: Non Firm PTP Schedule 1					-
	SFP/OS Revenues - Net of Ancillary Services					-

Duke Energy Carolinas, LLC. **Attachment J**
Transmission Rate Formula Support - Customer Prepayment for Network Upgrades Detail
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
NCEMC Anson Co. Project

Balances as of the Beginning of Year:

	Cash Payments	Accrued Interest	Total Liability
Beginning Balance	$ -	$ -	$ -
Allocation of Balance Refunds	0.00%	0.00%	

AFUDC Reversal Calculation:
(Beginning Balance)

(1)	(2) = 12 / (3)	(3) = x / (2)	(4)=[1-(3)]* 0
Depr. Rate	Avg. Depr. Life (Months)	% Depreciated 12/31/2008	Net AFUDC Reversal
0.00%	0.000	0.0000%	**0**

Test Year Refund History:

		Allocation of Amount Refunded			
Service Month	Amount Refunded	Current Interest	Cash Prepayment	Accrued Interest	Ending Liability Balance
Jan-09	$ -	$ -	$ -		$ -
Feb-09	$ -	$ -	$ -		$ -
Mar-09	$ -	$ -	$ -		$ -
Apr-09	$ -	$ -	$ -		$ -
May-09	$ -	$ -	$ -		$ -
Jun-09	$ -	$ -	$ -		$ -
Jul-09	$ -	$ -	$ -		$ -
Aug-09	$ -	$ -	$ -		$ -
Sep-09	$ -	$ -	$ -		$ -
Oct-09	$ -	$ -	$ -		$ -
Nov-09	$ -	$ -	$ -		$ -
Dec-09	$ -	$ -	$ -		$ -
	$ -	$ -	$ -	$ -	
Interest Disbursed	$ -	$ -		$ -	
Allocation of Ending Balance			$ -	$ -	$ -

AFUDC Reversal Calculation:
(Ending Balance)

(1)	(2) = 12 / (1)	(3) = x / (2)	(4)=[1-(3)]* 0
Depr. Rate	Avg. Depr. Life (Months)	% Depreciated 12/31/2009	Net AFUDC Reversal
0.00%	0.000	0.000%	**0**

Duke Energy Carolinas, LLC **Attachment K**
Transmission Rate Formula Support
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
GridSouth Amortization

1	Total GridSouth costs as of 12/31/2003	-
2	Wholesale allocated portion of GridSouth **Line 1*.2675**	-
3	Annual Amortization - Wholesale **Line 2 / 7 years**	-
4	Annual Amortization at System Level **Line 1 / 7 years**	#DIV/0!

	Wholesale Allocation Factor	**Reference**	**Total kW**	**Allocator**	**OATT Amount**
5	System Long Term Firm Transmission Peak Demand				
6	Firm Network Service for Self	400.17.e	-	0.0000	-
7	Firm Network Service for Others	400.17.f	-	1.0000	-
8	Long Term PTP Reservations	400.17.g	-	1.0000	-
9	Other Service	400.17.j	-		-
10	Total System Long Term Firm Transmission Load Peak Demand	Note M	-	0.00000	-

Duke Energy Carolinas, LLC **Attachment L**
Transmission Rate Formula Support
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Intangibles - Gross Plant
Accounts 302 and 303

Project Description	GL Balance 12/31/2008 Dr(Cr)	GL Balance 12/31/2009 Dr(Cr)	Average Balance	Allocation Factor		OATT Amount
Amounts Not Allocated to Transmission	-	-	$ -	Other	0.000000	$ -
Acquire/Maintain	-	-	$ -	OATT Labor	0.000000	$ -
Assistance Agency Portal Capit	-	-	$ -	OATT Labor	0.000000	$ -
BPM Software	-	-	$ -	OATT Labor	0.000000	$ -
Cgreen Influencing Custs Cont	-	-	$ -	OATT Labor	0.000000	$ -
Data Log Aggregation SW	-	-	$ -	TP	0.000000	$ -
Database Maintenance Tools	-	-	$ -	OATT Labor	0.000000	$ -
DP&S	-	-	$ -	OATT Labor	0.000000	$ -
EAM_CAROLINAS PHASE 2	-	-	$ -	OATT Labor	0.000000	$ -
Ebill Proj Software	-	-	$ -	OATT Labor	0.000000	$ -
Enterprise Asset Management Project	-	-	$ -	OATT Labor	0.000000	$ -
Financial System Replacement	-	-	$ -	OATT Labor	0.000000	$ -
Fleet Svcs Fleet Management Sy	-	-	$ -	OATT Labor	0.000000	$ -
FMIS Rel 3 Accounting	-	-	$ -	OATT Labor	0.000000	$ -
FMIS Release 1	-	-	$ -	OATT Labor	0.000000	$ -
FMIS Release 2	-	-	$ -	OATT Labor	0.000000	$ -
FMIS Release 3	-	-	$ -	OATT Labor	0.000000	$ -
FOOTPRINTS APPLICATION	-	-	$ -	TP	0.000000	$ -
Franklin Franchise	-	-	$ -	OATT Labor	0.000000	$ -
In House Software-Acct System	-	-	$ -	OATT Labor	0.000000	$ -
In House Software-Cash Mgmt	-	-	$ -	OATT Labor	0.000000	$ -
In House Software-Cust Billing	-	-	$ -	OATT Labor	0.000000	$ -
In House Software-Storm Team	-	-	$ -	OATT Labor	0.000000	$ -
Mobile Atlas(MapLink)	-	-	$ -	TP	0.000000	$ -
OE Express Core Pay Track	-	-	$ -	OATT Labor	0.000000	$ -
OE Express PE Hardware Costs	-	-	$ -	OATT Labor	0.000000	$ -
OE Express Release 1	-	-	$ -	OATT Labor	0.000000	$ -
OE Express Release 2B	-	-	$ -	OATT Labor	0.000000	$ -
OE Express System Enhancements	-	-	$ -	OATT Labor	0.000000	$ -
Phoenix Phase 5	-	-	$ -	OATT Labor	0.000000	$ -
Phoenix Phase 6	-	-	$ -	OATT Labor	0.000000	$ -
Phoenix Phases 1-4	-	-	$ -	OATT Labor	0.000000	$ -
Prioritization Tool - Asset	-	-	$ -	TP	0.000000	$ -
RELAY TESTING SYSTEM	-	-	$ -	TP	0.000000	$ -
Special Agency Assisstance Portal	-	-	$ -	OATT Labor	0.000000	$ -
SOC EMS Blade Srvr Upgrd-Sftwr	-	-	$ -	Schedule 1	0.000000	$ -
SOC Migration	-	-	$ -	Schedule 1	0.000000	$ -
SPOC Tracking System	-	-	$ -	OATT Labor	0.000000	$ -
TCC Migration Phase 1	-	-	$ -	TP	0.000000	$ -
Tivoli SW Purchase	-	-	$ -	OATT Labor	0.000000	$ -
Trans Billing System Replace	-	-	$ -	TP	0.000000	$ -
TRANS BILLING SYSTEM REPLACE	-	-	$ -	TP	0.000000	$ -
TWAMS Capital UT Top	-	-	$ -	TP	0.000000	$ -
UOF-Charlotte-Software	-	-	$ -	OATT Labor	0.000000	$ -
Witness Software	-	-	$ -	OATT Labor	0.000000	$ -
YEAR 2000 Platinum Tools	-	-	$ -	OATT Labor	0.000000	$ -
TOTAL	$ -	$ -	$ -			$ -

Duke Energy Carolinas, LLC
Transmission Rate Formula Support
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Intangibles - Accumulated Amortization

Attachment M

Project Description	GL Balance 12/31/2008 Dr(Cr)	GL Balance 12/31/2009 Dr(Cr)	Average Balance	Allocation Factor		OATT Amount
Amounts Not Allocated to Transmission	$ -	$ -	$ -	Other	0.000000	$ -
Acquire/Maintain	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Assistance Agency Portal Capit	$ -	$ -	$ -	OATT Labor	0.000000	$ -
BPM Software	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Brevard Business Office	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Brevard Merch/Col Hwy 64W	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Bulington Bus/Merch Office	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Carolina Cntr Lincolnton Merch/Bus Ofc	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Cgreen Influencing Custs Cont	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Cgreen Reenginrng Wachovia Ctr	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Charlotte Sat Off Wilkerson Bl	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Clemson Office	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Data Log Aggregation SW	$ -	$ -	$ -	TP	0.000000	$ -
Database Maintenance Tools	$ -	$ -	$ -	OATT Labor	0.000000	$ -
DP&S	$ -	$ -	$ -	OATT Labor	0.000000	$ -
EAM_CAROLINAS PHASE 2	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Ebill Proj Software	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Elkin Merch\Coll Ridgeway Cros	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Enterprise Asset Management Project	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Financial System Replacement	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Fleet Svcs Fleet Management Sy	$ -	$ -	$ -	OATT Labor	0.000000	$ -
FMIS Rel 3 Accounting	$ -	$ -	$ -	OATT Labor	0.000000	$ -
FMIS Release 1	$ -	$ -	$ -	OATT Labor	0.000000	$ -
FMIS Release 2	$ -	$ -	$ -	OATT Labor	0.000000	$ -
FMIS Release 3	$ -	$ -	$ -	OATT Labor	0.000000	$ -
FOOTPRINTS APPLICATION	$ -	$ -	$ -	TP	0.000000	$ -
FOOTPRINTS APPLICATION	$ -	$ -	$ -	TP	0.000000	$ -
Franklin Franchise	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Franklin Square Bus Office	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Gaffney Merch/C0ll Store	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Graham Street Merch/Bus Offices	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Greenville Merch/Coll	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Hendersonville Bus/Merch Office	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Hickory Merch/Coll Hickory Plaza	$ -	$ -	$ -	OATT Labor	0.000000	$ -
High Point Merch/Bus Offices	$ -	$ -	$ -	OATT Labor	0.000000	$ -
In House Software-Acct System	$ -	$ -	$ -	OATT Labor	0.000000	$ -
In House Software-Cash Mgmt	$ -	$ -	$ -	OATT Labor	0.000000	$ -
In House Software-Cust Billing	$ -	$ -	$ -	OATT Labor	0.000000	$ -
In House Software-Storm Team	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Inman Office	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Kannapolis Office	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Lancaster Merch/Coll Lancers	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Marion Business Office	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Mobile Atlas(MapLink)	$ -	$ -	$ -	TP	0.000000	$ -
Mocksville Merch/Coll Office	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Mocksville Office Op	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Mooresville Bus/Merchandising Office	$ -	$ -	$ -	OATT Labor	0.000000	$ -
N Summit Sq Merch/Bus Office	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Northeast Shop Cntr Merch/Bus	$ -	$ -	$ -	OATT Labor	0.000000	$ -
OE Express Core Pay Track	$ -	$ -	$ -	OATT Labor	0.000000	$ -
OE Express PE Hardware Costs	$ -	$ -	$ -	OATT Labor	0.000000	$ -
OE Express Release 1	$ -	$ -	$ -	OATT Labor	0.000000	$ -
OE Express Release 2B	$ -	$ -	$ -	OATT Labor	0.000000	$ -
OE Express System Enhancements	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Phoenix Phase 5	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Phoenix Phase 6	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Phoenix Phases 1-4	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Print Shop	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Prioritization Tool - Asset	$ -	$ -	$ -	TP	0.000000	$ -
Randleman Rd. Merch Store	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Reidsville Merch/Coll Freeway	$ -	$ -	$ -	OATT Labor	0.000000	$ -
RELAY TESTING SYSTEM	$ -	$ -	$ -	TP	0.000000	$ -
Replace Window HVAC North	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Salisbury Merchand/Bus Off	$ -	$ -	$ -	OATT Labor	0.000000	$ -
SOC EMS Blade Srvr Upgrd-Sftwr	$ -	$ -	$ -	Schedule 1	0.000000	$ -
SOC Migration	$ -	$ -	$ -	Schedule 1	0.000000	$ -
Special Agency Assisstance Portal	$ -	$ -	$ -	OATT Labor	0.000000	$ -
SPOC Tracking System	$ -	$ -	$ -	OATT Labor	0.000000	$ -
ST 27/28 Interior Restroom Renovati	$ -	$ -	$ -	OATT Labor	0.000000	$ -
ST 29/30 Interior Restroom Renovati	$ -	$ -	$ -	OATT Labor	0.000000	$ -
ST Restroom Renovations	$ -	$ -	$ -	OATT Labor	0.000000	$ -
ST1910 Coil Unit	$ -	$ -	$ -	OATT Labor	0.000000	$ -
ST27/28 Interior Restroom Reno	$ -	$ -	$ -	OATT Labor	0.000000	$ -
TCC Migration Phase 1	$ -	$ -	$ -	TP	0.000000	$ -
Tdvl 5603 Parking Lot Steps	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Tdvl Resource Recovery Gate	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Tivoli SW Purchase	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Toddville 5603 Load, DockStrs	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Toddville Central Warehouse	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Toddville Glove Lab Consolidat	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Toddville HVAC Replacement	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Trans Billing System Replace	$ -	$ -	$ -	TP	0.000000	$ -
TRANS BILLING SYSTEM REPLACE	$ -	$ -	$ -	TP	0.000000	$ -
TV 5603 New Dock Fasia/Lights	$ -	$ -	$ -	OATT Labor	0.000000	$ -
TWAMS Capital UT Top	$ -	$ -	$ -	TP	0.000000	$ -
UOF-Charlotte-Software	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Wachovia CTR S Tryon	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Wachovia Prod Tech Serv	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Westridge Square	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Wilkesboro Merch/Coll Office	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Winston Salem Merch/Bus Off Eastway	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Winston Salem Merch/Bus Off Parkway	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Witness Software	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Woolco Bldg	$ -	$ -	$ -	OATT Labor	0.000000	$ -
Yadkinville Bus/Merchandising Office	$ -	$ -	$ -	OATT Labor	0.000000	$ -
YEAR 2000 Platinum Tools	$ -	$ -	$ -	OATT Labor	0.000000	$ -
TOTAL	$ -	$ -	$ -			$ -

Duke Energy Carolinas, LLC **Attachment N**
Transmission Rate Formula Support
Utilizing Historic Cost Data for (Historic Years) with Year-End Average Balances
Intangibles - Amortization Expense

Project Description	GL Balance 12/31/2009 Dr(Cr)		Allocation Factor		OATT Amount	
Amounts Not Allocated to Transmission	$	-	Other	0.000000	$	-
Assistance Agency Portal Capit	$	-	OATT Labor	0.000000	$	-
BPM Software	$	-	OATT Labor	0.000000	$	-
Data Log Aggregation SW	$	-	TP	0.000000	$	-
Enterprise Asset Management Project	$	-	OATT Labor	0.000000	$	-
Enterprise Asset Management_Carolinas portion in C	$	-	OATT Labor	0.000000	$	-
FOOTPRINTS APPLICATION	$	-	TP	0.000000	$	-
Franklin Franchise	$	-	OATT Labor	0.000000	$	-
Prioritization Tool - Asset	$	-	TP	0.000000	$	-
RELAY TESTING SYSTEM	$	-	TP	0.000000	$	-
REPLACING CA2001 (NETWORK TRANS) AND P2P (PC	$	-	TP	0.000000	$	-
SOC EMS Blade Srvr Upgrd-Sftwr	$	-	Schedule 1	0.000000	$	-
Special Agency Assisstance Portal	$	-	OATT Labor	0.000000	$	-
Trans Billing System Replace	$	-	TP	0.000000	$	-
Trans Outage & Logging App	$	-	TP	0.000000	$	-
UOF-Charlotte-Software	$	-	OATT Labor	0.000000	$	-
TOTAL	**$**	**-**			**$**	**-**

Duke Energy Carolinas, LLC **Attachment O**

Weighted Depreciation Rates
At December 31, 2008

	Depreciable Group	Description	Rate
1	350	Transmission - Land Rights	1.16%
2	352-359	Transmission	2.03%
3	389	General-Land Rights	1.88%
4	390	General - Structures	3.46%
5	391-398	General	14.35%
6	391.1	General-EDP	12.50%
7	392	Passenger Cars	32.83%
8	392	Light Trucks	37.05%
9	392	Med Trucks	22.22%
10	392	Heavy Trucks	23.21%
11	392	Med Trucks/ Power Equip	25.55%
12	392	Heavy Trucks/ Power Equip	23.52%
13	392	Tractors (Gas)	40.72%
14	392	Tractors (Diesel)	15.38%
15	392	Trailers	7.11%
16	396	Trenchers and Cable Plows	15.22%
17	396	Rubber Tired Tractors	42.07%
18	396	Heavy Const. Equip	21.11%
19	396	Mobile Cranes	7.59%
20	396	Forklifts	37.96%
21	396	Trailers	14.32%
22	396	Misc Non-Hwy Equip	11.37%
23	396	Miscellaneous Equipment	8.74%

Duke Energy Carolinas, LLC
Transmission Rate Base
Contra AFUDC Amounts Recorded Pursuant to CFR 15.25(f)(2)

Attachment P

Description	Contra AFUDC Amount	Commercial Operation Date	first yr. partial year	31-Dec-08 deprec rate from CO date thru 11/12/1991	deprec rate effective 11/13/1991	31-Dec-09 weighted deprec rate year ending 12/31/1991	number of years from CO date ending 12/31/1990	accum deprec 12/31/1990	annual depr expense year ending 12/31/1991	accum deprec 12/31/1991	annual depr expense beginning 1/1/1992	number of years from 12/31/1991 ending 12/31/2004	accum deprec 12/31/2004	deprec rate effective 1/1/2005	number of years from 12/31/2004 ending 12/31/2007	accum deprec 12/31/2007	annual depr expense year ending 12/31/2008	accum deprec 12/31/2008	deprec rate effective 1/1/2009	annual depr expense year ending 12/31/2009	accum deprec 12/31/2009
								(B)*(E)*(H)	B*G	I+J	B*F		K+(L*M)			N+(C*O*P)	T-R	R+(C*P)		W-T	T+(C*U)
Production contra afudc																					
McGuire 1	$0	01-Dec-81	0.083	3.57%	3.09%	3.50%	9.083	$0	$0	$0	$0	13.000	$0	1.97%	3.000	$0	$0	$0	2.35%	$0	$0
McGuire 2	$0	01-Mar-84	0.833	3.57%	3.09%	3.50%	6.833	$0	$0	$0	$0	13.000	$0	1.97%	3.000	$0	$0	$0	2.35%	$0	$0
Radwaste	$0	13-Sep-86	0.300	3.57%	3.09%	3.50%	4.300	$0	$0	$0	$0	13.000	$0	1.97%	3.000	$0	$0	$0	2.35%	$0	$0
Total	$0							$0	$0	$0	$0		$0			$0	$0	$0		$0	$0
Transmission contra afudc																					
McGuire 1	$0	01-Dec-81	0.083	3.00%	2.57%	2.90%	9.083	$0	$0	$0	$0	13.000	$0	2.81%	3.000	$0	$0	$0	2.03%	$0	$0
McGuire 2	$0	01-Mar-84	0.833	3.00%	2.57%	2.90%	6.833	$0	$0	$0	$0	13.000	$0	2.81%	3.000	$0	$0	$0	2.03%	$0	$0
Radwaste		13-Sep-86	0.300	3.00%	2.57%	2.90%	4.300	$0	$0	$0	$0	13.000	$0	2.81%	3.000	$0	$0	$0	2.03%	$0	$0
Total	$0							$0	$0	$0	$0		$0			$0	$0	$0		$0	$0
Total contra afudc	$0							$0	$0	$0	$0		$0			$0	$0	$0		$0	$0

Account 0108499 -	
ARO Nuclear Accum Depr -Nuc	-
ARO accum- foss asbestos	-
ARO Fossil Accum Depr-land fill	-
ARO General Accum Depr - asbestos	-
ARO General Accum Depr-Solar	-
ARO Hydro Accum Depr	-
Total ARO	-

Duke Energy Carolinas, LLC
Transmission Rate Base
561.1- 561.4 Break Down

Attachment Q

	GL Balance 12/31/2009 Dr(Cr)
Total Accounts 561.1-561.4 (321.85.b:321.88.b)	$ -
	$ -
561.1 Load Dispatch Reliability	$ -
561.2 Load Dispatch Monitor and Operate Trans System	$ -
561.3 Load Dispatch Trans Service & Scheduling	$ -
561.4 Scheduling System Control and Dispatch Services	$ -
561.5 Reliability Planning	$ -
561.6 Transmission Service	$ -
561.7 Generation Interconnect Studies	$ -
	$ -
Form 1 (561.1-561.7)	$ -
Less amounts:	
Control center assets included in Transmission Service Revenue Requirement	$ -
Reliability Council fees related to retail service	$ -
Scheduling fees paid for off-system sales	$ -
Load Dispatch and Scheduling Expense included in Schedule 1	$ -

Duke Energy Carolinas, LLC | **Attachment R**
OATT Transmission Rate Formula Template Using Form 1-Data
Using Actual Cost Data for 20xx with Average Ratebase Balances
True Up from Billing Period to be Included in Projected ATRR for 20xx

Line	Reference	Amount	
Revenue Requirement True-Up - Network Service			
1 Actual Amount Billed to Customers	Company Records	$	-
2 Actual Amount Owed by Customers	Amounts Owed Worksheet	$	-
3 Actual ATRR True Up Amount (Over Recovery = negative; Under Recovery = positive)	Line 2 - Line 1	$	-
4 Interest True Up Amount	Interest Worksheet	$	-
5 Network Service Load Ratio Share Percentage			0.0000%
6 Total ATRR True Up Amount (Network)	(Line 3 + Line 4) / Line 5	$	-
Revenue Requirement True-Up - Point to Point Service (Long Term Firm)			
7 Actual PTP Reservation Quantities	Amounts Owed Worksheet		-
8 Actual Point to Point Rate	Amounts Owed Worksheet	$	-
9 Projected Point to Point Rate	DEC-Projected Rate, Page 1 Line 16		
10 Point to Point Price Variance	Line 8 - Line 9	$	-
11 ATRR True Up Amount (PTP)	Line 10 * Line 7	$	-
12 Interest True Up Amount	Interest Worksheet	$	-
13 PTP Load Ratio Share Percentage	Amounts Owed Worksheet		0.0000%
14 Total ATRR True Up Amount (PTP)	(Line 11 + Line 12) / Line 13	$	-

Interest Calculation	**FERC Quarterly Interest Rate***	**Monthly Interest Rate**
15 January _ 20xx	-	0.00%
16 February	-	0.00%
17 March	-	0.00%
18 April	-	0.00%
19 May	-	0.00%
20 June	-	0.00%
21 July	-	0.00%
22 August	-	0.00%
23 September	-	0.00%
24 October	-	0.00%
25 November	-	0.00%
26 December	-	0.00%
27 January _ 20xx	-	0.00%
28 February	-	0.00%
29 March	-	0.00%
30 Average Monthly Interest Rate		0.00%

* The interest is calcualted using the interest rate posted on the FERC website
http://www.ferc.gov/legal/acct-matts/interest-rates.asp#skipnavsub

Duke Energy Carolinas, LLC

OATT Transmission Rate Formula Template Using Form 1-Data

Attachment S1

Schedule 1 Duke Energy Carolinas Revenue Requirements

Form 1	Account	GL Balance 12/31/2008 Dr(Cr)	Amounts Related to System Operating Center	GL Balance 12/31/2009 Dr(Cr)	Amounts Related to System Operating Center	Remaining General Plant
207.86.g	(389) Land and Land Rights	$ -		$ -		$ -
207.87.g	(390) Structures and Improvements	$ -		$ -	$ -	$ -
207.88.g	(391) Office Furniture and Equipment	$ -		$ -	$ -	$ -
207.89.g	(392) Transportation Equipment	$ -		$ -		$ -
207.90.g	(393) Stores Equipment	$ -		$ -		$ -
207.91.g	(394) Tools, Shop and Garage Equipment	$ -		$ -		$ -
207.92.g	(395) Laboratory Equipment	$ -		$ -		$ -
207.93.g	(396) Power Operated Equipment	$ -		$ -		$ -
207.94.g	(397) Communication Equipment	$ -		$ -	$ -	$ -
207.95.g	(398) Miscellaneous Equipment	$ -		$ -		$ -
207.97.g	(399) Other Tangible Property	$ -		$ -		$ -
207.98.g	(399.1) Asset Reitrement Costs for General Plant	$ -		$ -		$ -
207.99.g	Total General Plant	$ -	$ -	$ -	$ -	$ -

Duke Energy Carolinas, LLC
OATT Transmission Rate Formula Template Using Form 1-Data
Using Actual Cost Data for (20xx) with Average Ratebase Balances
True Up from Billing Period to be Included in Projected Schedule 1 ARR

Attachment S2

Revenue Requirement True-Up - Network Service			
2 Actual Amount Billed to Customers		$	-
3 Actual Amount Owed by Customers	Amounts Owed Worksheet Sch 1	$	-
4 Actual Schedule 1 ARR Adjustment (Over Recovery = Credit; Under Recovery = Debit)		$	-
5 Interest True Up Amount	Interest Worksheet	$	-
6 Network Service Load Ratio Share Percentage	Amounts Owed Worksheet Sch 1		0.00%
7 Total Schedule 1 ARR True Up (Network)	(Line 4 + Line 5) / Line 6	$	-
Revenue Requirement True-Up - Point to Point Service (Long Term Firm)			
8 Actual PTP Reservation Quantities	Amounts Owed Worksheet Sch 1	$	-
9 Actual Point to Point Rate	Schedule 1, Line 21	$	-
10 Projected Point to Point Rate		$	-
11 Point to Point Price Variance	Line 9 - Line 10	$	-
12 Schedule 1 ARR True Up (PTP)	Line 11 * Line 8	$	-
13 Interest True Up Amount	Interest Worksheet	$	-
14 PTP Load Ratio Share Percentage	Amounts Owed Worksheet Sch 1		0.00%
15 Total Schedule 1 ARR True Up (PTP)	(Line 12 + Line 13) / Line 14	$	-

Interest Calculation	FERC Quarterly Interest Rate*	Monthly Interest Rate
16 January _ 20xx	-	0.00%
17 February	-	0.00%
18 March	-	0.00%
19 April	-	0.00%
20 May	-	0.00%
21 June	-	0.00%
22 July	-	0.00%
23 August	-	0.00%
24 September	-	0.00%
25 October	-	0.00%
26 November	-	0.00%
27 December	-	0.00%
28 January_ 20xx	-	0.00%
29 February	-	0.00%
30 March	-	0.00%
31 Average Monthly Interest Rate		0.00%

* The interest is calcualted using the interest rate posted on the FERC website
http://www.ferc.gov/legal/acct-matts/interest-rates.asp#skipnavsub

Worksheet A (Interest calcualtion for True- Up of ATRR)

NETWORK	ATRR True up Line 4/12	Interest Rate	Number of Months	Interest	Balance due/owed
January (20xx)	$ -	0.00%	12	$ -	
February	$ -	0.00%	11	$ -	
March	$ -	0.00%	10	$ -	
April	$ -	0.00%	9	$ -	
May	$ -	0.00%	8	$ -	
June	$ -	0.00%	7	$ -	
July	$ -	0.00%	6	$ -	
August	$ -	0.00%	5	$ -	
September	$ -	0.00%	4	$ -	
October	$ -	0.00%	3	$ -	
November	$ -	0.00%	2	$ -	
December	$ -	0.00%	1	$ -	
	$ -			$ -	$ -
January - May (20xx)	$ -	0.00%	5	$ -	$ -

NETWORK	True Up plus Interest	Interest Rate	Total Interest	Amoritization (Annuity	Balance due/owed
June (20xx)	$ -	0.00%	$ -	$0	$ -
July	$ -	0.00%	$ -	$0	$ -
August	$ -	0.00%	$ -	$0	$ -
September	$ -	0.00%	$ -	$0	$ -
October	$ -	0.00%	$ -	$0	$ -
November	$ -	0.00%	$ -	$0	$ -
December	$ -	0.00%	$ -	$0	$ -
January	$ -	0.00%	$ -	$0	$ -
February	$ -	0.00%	$ -	$0	$ -
March	$ -	0.00%	$ -	$0	$ -
April	$ -	0.00%	$ -	$0	$ -
May	$ -	0.00%	$ -	$0	$ -
			$ -		

PTP	ATRR True up Line 12/12	Interest Rate	Number of Months	Interest	Balance due/owed
January (20xx)	$ -	0.00%	12	$ -	
February	$ -	0.00%	11	$ -	
March	$ -	0.00%	10	$ -	
April	$ -	0.00%	9	$ -	
May	$ -	0.00%	8	$ -	
June	$ -	0.00%	7	$ -	
July	$ -	0.00%	6	$ -	
August	$ -	0.00%	5	$ -	
September	$ -	0.00%	4	$ -	
October	$ -	0.00%	3	$ -	
November	$ -	0.00%	2	$ -	
December	$ -	0.00%	1	$ -	
	$ -			$ -	$ -
January - May (20xx)	$ -	0.00%	5	$ -	$ -

PTP	True Up plus Interest	Interest Rate	Total Interest	Amoritization (Annuity	Balance due/owed
June (20xx)	$ -	0.00%	$ -	$0	$ -
July	$ -	0.00%	$ -	$0	$ -
August	$ -	0.00%	$ -	$0	$ -
September	$ -	0.00%	$ -	$0	$ -
October	$ -	0.00%	$ -	$0	$ -
November	$ -	0.00%	$ -	$0	$ -
December	$ -	0.00%	$ -	$0	$ -
January	$ -	0.00%	$ -	$0	$ -
February	$ -	0.00%	$ -	$0	$ -
March	$ -	0.00%	$ -	$0	$ -
April	$ -	0.00%	$ -	$0	$ -
May	$ -	0.00%	$ -	$0	$ -
			$ -		

(Interest Calculation for True-Up of Schedule 1)

NETWORK -Schedule 1	Scehdule 1 True up Line 4/12	Interest Rate	Number of Months	Interest	Balance due/owed
January (20xx)	$ -	0.00%	12	$ -	
February	$ -	0.00%	11	$ -	
March	$ -	0.00%	10	$ -	
April	$ -	0.00%	9	$ -	
May	$ -	0.00%	8	$ -	
June	$ -	0.00%	7	$ -	
July	$ -	0.00%	6	$ -	
August	$ -	0.00%	5	$ -	
September	$ -	0.00%	4	$ -	
October	$ -	0.00%	3	$ -	
November	$ -	0.00%	2	$ -	
December	$ -	0.00%	1	$ -	
	$ -			$ -	$ -
January - May (20xx)	$ -	0.00%	5	$ -	$ -

NETWORK -Schedule 1	True Up plus Interest	Interest Rate	Total Interest	Amoritization (Annuity	Balance due/owed
June (20xx)	$ -	0.00%	$ -	$0	$ -
July	$ -	0.00%	$ -	$0	$ -
August	$ -	0.00%	$ -	$0	$ -
September	$ -	0.00%	$ -	$0	$ -
October	$ -	0.00%	$ -	$0	$ -
November	$ -	0.00%	$ -	$0	$ -
December	$ -	0.00%	$ -	$0	$ -
January	$ -	0.00%	$ -	$0	$ -
February	$ -	0.00%	$ -	$0	$ -
March	$ -	0.00%	$ -	$0	$ -
April	$ -	0.00%	$ -	$0	$ -
May	$ -	0.00%	$ -	$0	$ -
			$ -		

PTP - Schedule 1	Schedule 1 True up Line 12/12	Interest Rate	Number of Months	Interest	Balance due/owed
January (20xx)	$ -	0.00%	12	$ -	
February	$ -	0.00%	11	$ -	
March	$ -	0.00%	10	$ -	
April	$ -	0.00%	9	$ -	
May	$ -	0.00%	8	$ -	
June	$ -	0.00%	7	$ -	
July	$ -	0.00%	6	$ -	
August	$ -	0.00%	5	$ -	
September	$ -	0.00%	4	$ -	
October	$ -	0.00%	3	$ -	
November	$ -	0.00%	2	$ -	
December	$ -	0.00%	1	$ -	
	$ -			$ -	$ -
January - May (20xx)	$ -	0.00%	5	$ -	$ -

PTP - Schedule 1	True Up plus Interest	Interest Rate	Total Interest	Amoritization (Annuity	Balance due/owed
June (20xx)	$ -	0.00%	$ -	$0	$ -
July	$ -	0.00%	$ -	$0	$ -
August	$ -	0.00%	$ -	$0	$ -
September	$ -	0.00%	$ -	$0	$ -
October	$ -	0.00%	$ -	$0	$ -
November	$ -	0.00%	$ -	$0	$ -
December	$ -	0.00%	$ -	$0	$ -
January	$ -	0.00%	$ -	$0	$ -
February	$ -	0.00%	$ -	$0	$ -
March	$ -	0.00%	$ -	$0	$ -
April	$ -	0.00%	$ -	$0	$ -
May	$ -	0.00%	$ -	$0	$ -
			$ -		

Worksheet B (Calculation of Amounts Owed under Actual Transmission Revenue Requirement)

	Monthly demands:				Billing Demands				Network			Point to Point		
	Monthly system demand excl. network and firm PTP	Monthly network service demand	Monthly long term firm PTP reservations	Total	Monthly system demand excl. network and firm PTP	Monthly network service demand	Monthly long term firm PTP reservations	Total	Actual Monthly Revenue Requirement	LRS percentage	**Amount due based on actual ATRR**	Actual Monthly Point-to-Point Rate	PTP Reservation Quantities	**Amount due based on actual ATRR**
Jan (Historical year)	-	-	-	-										
Feb	-	-	-	-										
Mar	-	-	-	-										
Apr	-	-	-	-										
May	-	-	-	-										
Jun	-	-	-	-										
Jul	-	-	-	-										
Aug	-	-	-	-										
Sept	-	-	-	-										
Oct	-	-	-	-										
Nov	-	-	-	-										
Dec	-	-	-	-										
Jan (Projected Year)	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Feb	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Mar	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Apr	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
May	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Jun	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Jul	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Aug	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Sept	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Oct	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Nov	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Dec	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Sum of Billing and System Demand for Projected Year			-	-		-		-			$ -		-	$ -
Load Ratio Share Percentages (Ratio of Customer Billing Demands to System Demands)				0.0000%				0.0000%						

Worksheet C (Calculation of Amounts Owed under Actual Schedule 1 Revenue Requirement)

	Monthly demands:				Billing Demands				Network			Point to Point		
	Monthly system demand excl. network and firm PTP	Monthly network service demand	Monthly long term firm PTP reservations	Total	Monthly system demand excl. network and firm PTP	Monthly network service demand	Monthly long term firm PTP reservations	Total	Actual Monthly Revenue Requirement	LRS percentage	**Amount due based on actual Schedule 1 RR**	Actual Monthly Point-to-Point Rate	PTP Reservation Quantities	**Amount due based on actual Schedule 1 RR**
Jan (Historical year)	-	-	-	-										
Feb	-	-	-	-										
Mar	-	-	-	-										
Apr	-	-	-	-										
May	-	-	-	-										
Jun	-	-	-	-										
Jul	-	-	-	-										
Aug	-	-	-	-										
Sept	-	-	-	-										
Oct	-	-	-	-										
Nov	-	-	-	-										
Dec	-	-	-	-										
Jan (Projected Year)	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Feb	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Mar	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Apr	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
May	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Jun	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Jul	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Aug	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Sept	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Oct	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Nov	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Dec	-	-	-	-	-	-	-	-	$ -	0.0000%	$ -	$ -	-	$ -
Sum of Billing and System Demand for Projected Year			-	-		-		-			$ -		-	$ -
Ratio of Customer Billing Demands to System Demands				0.00%				0.00%						

Schedule 10-B

Duke Energy Carolinas Formula Rate Principles

The following notes apply to calculations in the Formula Rate and are an integral part of the Formula Rate.

1.0 Transmission-related Revenue Credits.
(i) The transmission-related revenue credits in the Formula Rate shall be determined in the following manner:

(1) All revenues associated with facilities allocated to the transmission function, including both direct and indirect allocations (*e.g.*, general and intangible plant and administrative and general expense) shall be treated as revenue credits in the Formula Rate. Such revenue credits shall include, but shall not be limited to, transmission facilities lease/rental payments, direct assignment facilities charges, and general plant-related income.

(2) Transmission revenues from Short-Term Firm and Non-Firm Transmission Services under the OATT and transmission service similar to Short-Term Firm or Non-Firm Transmission Services under the OATT shall be treated as revenue credits in the Formula Rate.

(3) Transmission services revenues and Schedule 1 – Scheduling, System Control and Dispatch Service ancillary service revenues from Federal Energy Regulatory Commission (FERC) Account 456.1 shall be treated as revenue credits in the Formula Rate, but all other ancillary services revenues from FERC Account 456.1 shall not be revenue credits in the Formula Rate.

(4) Revenues associated with indirect allocations of costs to the transmission function (*e.g.*, general and intangible plant) shall be allocated to the transmission function in the Formula Rate based on the same underlying indirect allocations of costs and treated as a revenue credit.

2.0 Cash Working Capital. The Formula Rate shall include cash working capital based on a formulary approach as follows: 1/8 multiplied by the total of operation and maintenance expense.

3.0 Prepayments for Network Upgrades by Generators. The Formula Rate shall include as an offset to rate base in the Formula Rate the amount of refundable prepayments made by generators for network upgrades that Duke Energy Carolinas has not refunded to the OATT transmission customer as credits to its transmission charges; this will ensure Duke Energy Carolinas does not earn a return on those funds. Correspondingly, the amount of interest paid to OATT transmission customers as their balances are credited against their transmission service shall be included as an expense in the Formula Rate. Duke Energy Carolinas shall not capitalize and add any AFUDC to the completed cost of such network upgrades, but instead will include only the balance of any unrefunded interest accrued at the FERC refund interest rate as an addition to rate base.

4.0 Credits for Customer-owned Facilities under FERC Order No. 890. The Formula Rate shall include a placeholder for any future credits for customer-owned facilities to prevent any under-recovery of revenues by Duke Energy Carolinas due to any credits provided to OATT transmission customers for their own facilities.

5.0 Transmission Provider's Compliance with Order No. 2003. In accordance with FERC Order No. 2003, the Formula Rate shall exclude any transmission plant that meets the definition of "Interconnection Facilities" and was placed in service for Duke Energy Carolinas' own generation facilities after March 15, 2000. The Formula Rate shall also exclude generator step-up transformers and transmission lines less than 44kv.

6.0 Accumulated Deferred Income Taxes (ADIT). Accumulated deferred income taxes (ADIT) reflected in the Formula Rate shall be only such amounts as are properly allocated or assigned to the transmission function. In each Annual Update (as defined in the Formula Rate Implementation Protocols), Duke Energy Carolinas shall provide a spreadsheet that shows the functionalization of the FERC Form No. 1 reported amounts for ADIT and supports the amount of ADIT to be reflected in the Formula Rate. The functionalization shall be based on the most recent federal income tax return information available at the time the calculation of actual annual revenue requirements is performed. Because the unamortized balance of GridSouth costs is excluded from rate base, there will be no ADIT offset in the formula rate calculation related to GridSouth unamortized balance.

7.0 Intangible Plant. Intangible plant reflected in the Formula Rate shall only be such amounts as are properly allocated or assigned to the transmission function. In each Annual Update (as defined in the Formula Rate Implementation Protocols), Duke Energy Carolinas shall provide a spreadsheet that shows the functionalization of the FERC Form No. 1 reported amounts for Intangible plant and the associated accumulated amortization and supports the amounts to be reflected in the Formula Rate.

8.0 FERC Account 561. Consistent with FERC Order No. 668, the Formula Rate reflects the appropriate treatment of Account 561 subaccounts such that the Formula Rate includes only those items associated with Transmission Service and Schedule 1 – Scheduling, System Control and Dispatch Service.

9.0 Billing Demands. For firm point to point and network transmission service, billing demands will be at the meter level (net of losses).

10.0 Directly Assigned or Assignable Costs. The Formula Rate shall exclude all costs that are properly directly assigned or assignable to one or more particular customers, including costs directly assigned or assignable to Duke.

11.0 Radial Facilities: The Formula Rate shall exclude the cost of New Radial Facilities as defined in the Formula Rate. At the time that a New Radial Facility owned by a Customer experiences a change in characteristics such that it meets the Commission's standards to be treated as an integrated facility, including the standards and policies set forth in Order No. 890-B,[1] the Customer shall then be entitled at its election to Order 890 Credits for the undepreciated portion of the cost of such facility. At the time that a New Radial Facility owned by Duke experiences a change in characteristics such that it meets the Commission's standards to be treated as an integrated facility, the undepreciated portion of the cost of such facility may then be included in the Formula Rate. The Formula Rate shall include the cost of radial lines and facilities, and upgrades thereto, which were placed in service prior to the effective date of the Formula Rate.

12.0 Load Ratio Share. The calculation of load ratio share for network transmission service shall be based upon a numerator for each customer that uses coincident peak network loads measured at the meter level (net of losses) and a denominator (the Duke Energy Carolinas system peak transmission demand) based on the 12 month rolling average of system peak demands at the generation level (including losses).

Where long-term firm transmission obligations undertaken by Duke Energy Carolinas, either for off-system sales or transmission services, are based upon reservations of capacity, the denominator (system peak transmission demand) for the load ratio share calculation for network transmission service shall include the contract demands for such obligations in lieu of the actual coincidental peak demands at the time of the Duke Energy Carolinas monthly system transmission demand peak. The denominator shall exclude Short Term Transmission Service and Non-Firm Transmission Service demands at the time of the Duke Energy Carolinas monthly system transmission demand peak.

[1] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 (2007), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261, *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

SCHEDULE 10-C

NETWORK INTEGRATION TRANSMISSION SERVICE

[CP&L Zone]

In the CP&L Zone, the Transmission Customers shall compensate the Transmission Provider each month for Network Load for the applicable month as provided in Attachment H.

SCHEDULE 11

~~**Distribution Substation Service**~~

DISTRIBUTION SUBSTATION SERVICE

[FPC Zone~~ Only~~]

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity or Network Load, as applicable, delivered to the Transmission Provider's Distribution Substations in the FPC Zone at the applicable charges set forth below:

11.1 Monthly Period: $722/MW month.

11.2 Weekly Period: $166.61/MW week.

11.3 Daily Period: The charge for Daily Period delivery on ~~On~~on-~~P~~peak ~~D~~days shall be $33.32/MW day and the charge for Daily Period delivery on ~~O~~off-~~P~~peak ~~D~~days shall be $23.74/MW day. The total demand charge in any Weekly Period, pursuant to a reservation for Daily Period delivery, shall not exceed the Weekly Period rate times the highest amount in kilowatts of Reserved Capacity in any Daily Period during such Weekly Period.

11.4 Hourly Period: The maximum charge for Hourly Period service during ~~On~~on-~~P~~peak ~~H~~hours shall be $2.08/MW hour and the maximum charge for Hourly Period service during ~~O~~off-~~P~~peak ~~H~~hours shall be $0.99/MW hour. The total demand charge in any Daily Period, pursuant to a reservation for Hourly Period delivery, shall not exceed the Daily Period rate times the highest amount in kilowatts of Reserved Capacity in any Hourly Period during such Daily Period. In addition, the total demand charge in any Weekly Period, pursuant to a reservation for Hourly Period or Daily Period delivery, shall not exceed the Weekly Period rate times the highest amount in kilowatts of Reserved Capacity in any Hourly Period during such Weekly Period.

Billing determinants are the Transmission Customer's Reserved Capacity or Network Load for service taken at distribution Points of Delivery.

NOTE: All quantities used in calculating the Transmission Customer's Reserved Capacity or Network Load, as applicable, shall be established at the transmission system input level, *i.e.*, shall include the transmission capacity amount associated with any losses.

SCHEDULE 12

~~**Long Term and Short Term**~~
~~**Network Contract Demand Transmission Service**~~

LONG-TERM AND SHORT-TERM
NETWORK CONTRACT DEMAND TRANSMISSION SERVICE

The Transmission Customer shall compensate the Transmission Provider for Reserved Capacity in the FPC Zone at the sum of the applicable charges~~ for a zone~~ set forth below.

Charges:

~~The charge for Network Contract Demand Transmission Service shall be based on the Zone in which the energy being transmitted is consumed or, if the energy is transmitted to an interface with another transmission provider, the Zone in which transmission service is last provided by the Transmission Provider. The applicable zonal charges are set out below.~~

~~**A. CP&L Zone**~~

~~**A.12.1 Annual Period**: one-twelfth of the annual demand charge of $10,800/MW of Reserved Capacity per month.~~

~~**A.12.2 Monthly Period:** $900/MW of Reserved Capacity per month.~~

~~**A.12.3 Weekly Period:** $208/MW of Reserved Capacity per week.~~

~~**A.12.4 Daily Period:** $42/MW of Reserved Capacity per On-Peak Day and $30/MW of Reserved Capacity per Off-Peak Day. The total demand charge in any Weekly Period, pursuant to a reservation for Daily Period delivery, shall not exceed the rate specified in section A.12.3 times the highest amount in kilowatts of Reserved Capacity in any Daily Period during such Weekly Period.~~

~~**A.12.5 Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer- initiated~~

~~requests for discounts (including requests for use by one's wholesale merchant or affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discount transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.~~

~~**A.12.6 Unauthorized Use:** For each day that the Transmission Customer's use of the Transmission System during any hour of that day exceeds the amount of the Transmission Customer's Reserved Capacity, the Transmission Customer shall pay the Transmission Provider a penalty charge based on a rate equal to 150% of the daily rate for firm point-to-point transmission service provided multiplied by the amount of the maximum excess usage in any hour in the day of the Transmission Customer's reservation. Losses delivered to the CP&L Zone by the Transmission Customer will not be included in the Transmission Customer's usage for determination of the charge set out herein.~~

~~**A.12.7 Additional Charges:** The Transmission Customer will compensate CP&L for any facility additions or redispatch costs in accordance with Sections 13.5, 27 and 45.2 of the Tariff. Redispatch costs will be computed in accordance with the methodology outlined in Attachment J.~~

~~**A.12.8 Losses:** For purposes of billing, the Reserved Capacity to be applied under Sections A.12.1 through A.12.4 of this schedule shall not include losses purchased or provided by the Transmission Customer.~~

~~**B. FPC Zone**~~

~~B~~A.12.1 **Monthly, Weekly and Daily Periods:** The rates for the Monthly Period, the Weekly Period, the Daily Period for ~~On~~on-~~P~~peak ~~D~~days and the Daily Period for ~~O~~off-~~P~~peak ~~D~~days are derived from the Formula Rate, which is set forth in OATT Schedules ~~10.2~~10-A.2 and ~~10.3.~~10-A.3. The resulting rates are posted on the Transmission Provider's OASIS. The Formula Rate is implemented in accordance with the OATT Schedule ~~10.1~~10-A.1 Formula Rate Implementation Protocols.

~~B~~A.12.2 **Daily Period:** The total demand charge in any Weekly Period, pursuant to a reservation for Daily Period delivery, shall not exceed the Weekly Period rate times the highest amount in kilowatts of Reserved Capacity in any Daily Period during such Weekly Period.

NOTE: All quantities used in calculating the Transmission Customer's Reserved Capacity shall be established at the transmission system input level, *i.e,*. shall include the transmission capacity amount associated with any losses.

~~B~~A.12.3 **Annual Update:** The charges for Network Contract Demand Service shall be updated annually on June 1st of each year in accordance with the OATT Schedule ~~10.1~~10-A.1 Formula Rate Implementation Protocols.

~~B~~A.12.4 **Unauthorized Use:** A Transmission Customer that exceeds its Reserved Capacity shall pay a charge equal to the amount of the capacity delivered in excess of the Reserved Capacity multiplied by 150% of the applicable charge for the lesser of the term of that transaction or one month.

~~B~~A.12.5 **Regulatory Assessment:** The Transmission Customer shall pay a portion of the charge by FERC pursuant to 18 C.F.R. § 382.201 related to service under this Tariff. The Regulatory Assessment Expense shall be allocated to the Transmission Customer on an annual basis in the year following the year in which transmission service is rendered based on the megawatt-hours of service provided to the Transmission Customer or based upon such other method as these fees are assessed by FERC.

SCHEDULE ~~9~~13

~~Generator Imbalance Service~~
GENERATOR IMBALANCE SERVICE

Generator Imbalance Service is provided when a difference occurs between the output of a generator located in the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. The Transmission Provider must offer this service, to the extent it is physically feasible to do so from its resources or from resources available to it, when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule or a penalty for hourly energy imbalances under Schedule 4 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.

~~9.1~~ The Transmission Provider shall establish charges for generator imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of each month, at 100 percent of incremental or decremental cost, (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of incremental cost or 75 percent of decremental cost, except that an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of this Schedule is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

Notwithstanding the foregoing, deviations from scheduled transactions in order to respond to directives by the Transmission Provider, a balancing authority, or a reliability coordinator shall not be subject to the deviation bands identified above and, instead, shall be settled financially, at the end of the month, at 100 percent of incremental ~~or~~and decremental cost. Such directives may include instructions to correct frequency decay, respond to a reserve sharing event, or change output to relieve congestion.

~~9.2~~ For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched for any purpose, e.g., to supply the Transmission Provider's Native Load Customers, correct imbalances, or make off-system sales, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable. Start-up cost will also include the cost to cycle a unit back on-line that was removed from service to accommodate an excess Generator Imbalance purchase.

13.1 CP&L Zone and FPC Zone:

CP&L and FPC utilize the PCI GenTrader generation resource optimization model to determine the incremental and decremental cost. CP&L and FPC use actual generation and load parameters and spot value of relevant commodities as data for this optimization model.

~~9.3~~13.1.1 Credits for Generator Imbalance Revenues in the CPL Zone and the FPC Zone

The Transmission Provider will credit revenues that it receives in excess of the incremental costs it incurs to accommodate generator imbalances ("penalty revenues") to all non-offending Transmission Customers (including Affiliated Transmission Customers) and to the Transmission Provider on behalf of its own customers (Native Load Customers). The credits shall be calculated and allocated as set out below.

The penalty revenues for which the Transmission Provider provides credits consist of the following: for each undersupply generator imbalance in excess of the deviation band in an hour, the amount by which the Transmission Provider's revenues for such imbalance pursuant to ~~Section 9.1~~this Schedule 13 exceed the incremental cost incurred to supply that imbalance.

The imbalance penalty revenues calculated for each hour shall be credited based on the ratio of the transmission revenues from each Network Transmission Customer or Point-to-Point Transmission Customer that did not experience an energy imbalance in excess of the deviation band in an hour to the sum of the transmission revenues from all Transmission Customers that did not experience energy imbalances in the hour. A Transmission Customer that experiences an energy imbalance in excess of the first tier deviation band in an hour shall not receive a credit for that hour.

~~9.4~~ The Transmission Provider shall disburse accumulated penalty revenues, plus interest calculated in accord with 18 C.F.R. § 35.19a, when the accumulated amount of penalty revenues collected under ~~Section 9.1 of~~ this ~~schedule~~Schedule 13 and Section 4.1 of Schedule 4 reaches $100,000. However, effective as of April 1, 2009 and every April 1st thereafter, if a distribution has not been made within the previous twelve-month period, a distribution will be made no later than April 1 of that calendar year.

13.2 DEC Zone

13.2.1 Credits for Generator Imbalance Revenues in the DEC Zone

The Transmission Provider will credit revenues that it receives in excess of the costs it incurs to accommodate generator imbalances pursuant to Schedule 4.

ATTACHMENT A

~~**Form Of Service Agreement For**~~

~~**Firm Point-To-Point Transmission Service**~~

FORM OF SERVICE AGREEMENT FOR FIRM POINT-TO-POINT TRANSMISSION SERVICE

1.0 This Service Agreement, dated as of _______________, is entered into, by and between Carolina Power & Light Company/Florida Power Corporation/Duke Energy Carolinas, LLC (the Transmission Provider), and ____________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

5.1 The Transmission Customer is responsible for replacing Real Power Losses associated with all transmission service in accordance with Section 15.7 of the Tariff. The Transmission Customer must identify the party responsible for supplying Real Power Losses before the transaction.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

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____

Transmission Customer:

Transmission Customer:

____

____

____

~~7.0 [CP&L Zone: When load is being served by the Transmission Customer in the CP&L Zone, the Transmission Customer shall maintain a power factor of 100% to 90% lagging at each point of delivery determined on the basis of the 60-minute metered or computed reactive demand (kVar) for each hour of the month and the corresponding 60-minute metered or computed kilowatt demand for that hour. In addition, the Transmission Customer shall maintain a power factor of 100% to 95% lagging at each point of delivery, determined on the basis of the 60-minute metered or computed kilowatt demand at the time of CP&L's monthly transmission system peak and the corresponding 60-minute reactive demand (kVar) for that hour. To the extent the Transmission Customer owns or operates reactive devices which could cause reactive power to flow onto the CP&L system, CP&L and the Customer will develop procedures governing the Customer's delivery of reactive power to the CP&L system. In the event that the Transmission Customer does not satisfy the power factor requirements outlined above or the Parties cannot agree on the procedures governing the customer's delivery of reactive power, CP&L reserves the right to make a unilateral filing with FERC under Section 205 of the Federal Power Act seeking authorization to either (i) assess appropriate charges to the Transmission Customer for reactive power supplied to the Transmission Customer by CP&L up to the level of minimum power factor requirement, or (ii) install power factor correction equipment sufficient to bring the Transmission Customer's power factor into compliance with the power factor requirements, and to assess the Transmission Customer the reasonable cost of such equipment.]~~

7.0 ~~[~~FPC Zone: The Transmission Customer shall comply with the power factor requirements set forth in OATT Attachment V.~~]~~

8.0 The Transmission Customer will be responsible for Redispatch cost and/or Direct Assignment Facilities cost as follows

____

____

9.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ________________ _______________ __________________

Name Title Date

Transmission Customer:

By: ______________________ ________________ ______________
Name Title Date

Specifications For Long-Term Firm Point-To-Point
Transmission Service

1.0 Term of Transaction: ____________________________________

Start Date: ____

Termination Date: ______________________________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt:_____________________________________

Delivering Party:_______________________________________

4.0 Point(s) of Delivery:____________________________________

Receiving Party:_______________________________________

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity):_____________________________________

6.0 Designation of party(ies) subject to reciprocal service obligation:
____
____
____

7.0 Name(s) of any Intervening Systems providing transmission service:
____
____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:
____
____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:

____

____

8.4 Ancillary Services Charges: ________________

____

____

____

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____

9.0 Party Responsible for Providing Real Power Losses:_________

____

____

____

ATTACHMENT A-1

~~**Form Of Service Agreement For**~~
~~**The Resale, Reassignment Or Transfer Of**~~
~~**Point-To-Point Transmission Service**~~

FORM OF SERVICE AGREEMENT FOR THE RESALE, REASSIGNMENT OR TRANSFER OF POINT-TO-POINT TRANSMISSION SERVICE

1.0 This Service Agreement, dated as of _______________, is entered into, by and between ____________ (the Transmission Provider), and ____________ (the Assignee).

2.0 The Assignee has been determined by the Transmission Provider to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part II of the Transmission Provider's Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section 23.1 of this Tariff) and the Assignee, to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section 23.2 of this Tariff.

4.0 The Transmission Provider shall credit the Reseller for the price reflected in the Assignee's Service Agreement or the associated OASIS schedule.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

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Assignee:

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____

6.0 The Tariff is incorporated herein and made a part hereof.

The remaining pages to Attachment A-1
contain no changes of substance and are not included.

ATTACHMENT B

FORM OF SERVICE AGREEMENT FOR NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

~~Form Of Service Agreement For Non-Firm Point-To-Point~~

~~Transmission Service~~

1.0 This Service Agreement, dated as of _______________, is entered into, by and between Carolina Power & Light Company/Florida Power Corporation/Duke Energy Carolinas, LLC (the Transmission Provider), and ____________ (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

5.1 The Transmission Customer is responsible for replacing Real Power Losses associated with all Transmission Service in accordance with Section 15.7 of the Tariff. The Transmission Customer must identify the party responsible for supplying Real Power Losses before the transaction.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

<u>Transmission Customer:</u>

____

____

____

~~7.0 [CP&L Zone: When load is being served by the Transmission Customer in the CP&L Zone, the Transmission Customer shall maintain a power factor of 100% to 90% lagging at each point of delivery determined on the basis of the 60-minute metered or computed reactive demand (kVar) for each hour of the month and the corresponding 60-minute metered or computed kilowatt demand for that hour. In addition, the Transmission Customer shall maintain a power factor of 100% to 95% lagging at each point of delivery, determined on the basis of the 60-minute metered or computed kilowatt demand at the time of CP&L's monthly transmission system peak and the corresponding 60-minute reactive demand (kVar) for that hour. To the extent the Transmission Customer owns or operates reactive devices which could cause reactive power to flow onto the CP&L system, CP&L and the Transmission Customer will develop procedures governing the Transmission Customer's delivery of reactive power to the CP&L system. In the event that the Transmission Customer does not satisfy the power factor requirements outlined above or the Parties cannot agree on the procedures governing the customer's delivery of reactive power, CP&L reserves the right to make a unilateral filing with FERC under Section 205 of the Federal Power Act seeking authorization to either (i) assess appropriate charges to the Transmission Customer for reactive power supplied to the Transmission Customer by CP&L up to the level of minimum power factor requirement, or (ii) install power factor correction equipment sufficient to bring the Transmission Customer's power factor into compliance with the power factor requirements, and to assess the Transmission Customer the reasonable cost of such equipment.]~~

7.0 ~~[~~FPC Zone: The Transmission Customer shall comply with the power factor requirements set forth in OATT Attachment V.~~]~~

8.0 The Transmission Customer will be responsible for Redispatch cost and/or Direct Assignment Facilities cost as follows: ______________________________________
____

9.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ____________________ _______________ ________________
Name Title Date

Transmission Customer:

By: ____________________ _______________ ________________
Name Title Date

ATTACHMENT C-1

~~Methodology To Assess Available Transfer Capability~~
METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

~~A.~~ (CP&L ~~Zone~~ZONE)

I. AVAILABLE TRANSFER CAPABILITY (ATC)

A. Types of ATC and Transmission Service Requests (TSR) evaluations that are done at CP&L:

CP&L recognizes time-variant power flow conditions on the interconnected transmission network. CP&L uses the same methodology and base assumptions, as documented below, to determine ATC in the Operating Horizon and similar principles and base assumptions for evaluating TSRs in the Planning Horizon (beyond 13 months):

Operating Scheduling Horizon ATC

Scheduling horizon definition:

CP&L uses a process which builds neighboring *NERC tags*, significant SDX outages, and load forecasts into the *hourly* powerflow snapshots used to determine the initial flows on the flowgates used in the AFC/ATC calculation process. For external coordinated flowgates where coordination agreements have been signed, the CP&L calculated Available Flowgate Capabilities (AFCs) will be replaced with owner's AFCs for the time horizon being studied. With recent developments in using real-time flows, the transmission provider utilizing those flows can over-ride the external coordinated flowgate AFCs during the next few hours if agreed to by the external coordinated flowgate owner. This process also develops distribution factors for each snapshot which are used to quickly schedule and evaluate the impact of new TSRs on top of the calculated flowgate values. Available headroom on each path's most constraining flowgate can be sold if not limited by contract constraints.

Operating - Reservation Horizon ATC (Beyond the scheduling horizon up to 13 months):

CP&L uses a process which builds neighboring ***OASIS reservations*** and SDX outages and load forecasts into the ***hourly, daily, and monthly*** powerflow snapshots used to determine the initial flows on the flowgates used in the ATC calculation process. For external flowgates where coordination agreements have been signed, the CP&L calculated AFCs will be replaced with owner's AFCs for the time horizon being studied. This process also develops distribution factors for each snapshot which are used to quickly schedule and evaluate the impact of new TSRs on top of the calculated flowgate values. Available headroom on each path's most constraining flowgate can be sold if not limited by contract constraints.

The remaining pages to Attachment C-1
contain no changes of substance and are not included.

ATTACHMENT C-2

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

~~B.~~ (FPC ~~Zone~~ ZONE)

This Attachment C-2 describes the FPC methodology used to assess Total Transfer Capability ("TTC") and Available Transfer Capability ("ATC"). The methodology as described in this document applies to TTC and ATC calculations and is based upon the "Florida Reliability Coordinating Council ("FRCC") ATC Document". Please see https://www.frcc.com/ATCWG/Shared%20Documents/FRCC%20ATC%20Coordination%20Procedures.pdf.

MATHEMATICAL ALGORITHM:

The table below describes the mathematical algorithms used to calculate firm and non-firm ATC for the scheduling, operating and planning horizons.

A more detailed description of FPC's ATC algorithms may be accessed on FPC's OASIS at https://www.oatioasis.com/FPC/FPCdocs/ATC_Mathematical_Algorithm.doc

	CALCULATION HORIZON		
	SCHEDULING	**OPERATING**	**PLANNING**
FIRM	N/A	ATC = TTC - ETC - TRM - CBM	ATC = TTC - ETC - TRM - CBM
NON-FIRM	ATC = TTC - ETC	ATC = TTC - ETC - CBM	ATC = TTC - ETC - CBM

N/A - FIRM PRODUCTS DO NOT EXIST IN SCHEDULING HORIZON .

FPC uses a flow based (network response) calculation method to determine ATC on its paths within the FRCC. In the Operating horizon, calculations are performed using Power Technologies Incorporated's ("PTI") PSS/E load flow program. PSS/E efficiently calculates the impact of transactions on network elements and identifies the most limiting contingencies and limiting facilities. In the Planning horizon, ATC is determined by explicitly modeling requested transactions using PTI's PSS/E load flow program. PSS/E relies upon load flow cases that incorporate the base assumptions. These "base cases" are derived from the peak load base cases that FRCC Transmission Working Group ("TWG") annually updates and represent seasonal load profiles, in-service generating units, in-service transmission facilities and firm interchange contracts according to NERC guidelines. The FRCC ATCWG uses cases developed above to create loadflow cases of planned operations, modeling the expected load levels, facility outages, and confirmed firm and non-firm transactions for use in calculating hourly and daily ATC and TTC. — In addition, the ATCWG provides monthly cases for the next 12 months that model the combination of projected highest load and most significant maintenance outage scenario. FPC currently includes the total load; therefore, interruptible demands are not utilized in determining ATC values. Interruptible demands are loads within FPC that may be curtailed via conditions of

The remaining pages to Attachment C-2
contain no changes of substance and are not included.

ATTACHMENT C-3

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY (DEC ZONE)

1. Purpose and Scope

This Attachment C-3 sets forth the methodology to assess Available Transfer Capability (ATC). Any provisions herein shall be construed consistent with NERC MOD standards and any other applicable reliability standard.

2. Definitions

The terms defined below, to the extent defined differently than in Section 1 of Part I of the Tariff, apply only to this Attachment C-3.

2.1. Available Flowgate Capability (AFC)

A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses.

2.2. Available Transfer Capability (ATC)

A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

2.3. ATC Path

Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any path posted on OASIS.

2.4. Balancing Authority

The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

2.5. Balancing Authority Area (BA Area)

The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

2.6. Capacity Benefit Margin (CBM)

The amount of firm transmission transfer capability preserved by the Transmission Service Provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

2.7. Existing Transmission Commitments (ETC)

Committed uses of a Transmission Service Provider's transmission system considered when determining ATC or AFC.

2.8. Flowgate

A mathematical construct, comprised of one or more monitored transmission facilities and optionally one or more contingency facilities, used to analyze the impact of power flows upon the bulk electric system.

2.9. Flowgate Methodology

The Flowgate Methodology is characterized by identification of key facilities as Flowgates. Total Flowgate Capabilities (TFCs) are determined based on facility ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).

2.10. Generator Shift Factor (GSF)

A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.

2.11. Interconnection Reliability Operating Limit (IROL)

A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk electric system.

2.12. Load-Serving Entity (LSE)

Secures energy and Transmission Service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.

2.13. Tag Dump

A database that contains tagging data for the Eastern Interconnection.

2.14. System Data Exchange (SDX)

A database that serves as a repository for transmission outages, generation outages, and load forecast data for the Eastern Interconnection.

2.15. Outage Transfer Distribution Factor (OTDF)

In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system facilities removed from service (outaged).

2.16. Point of Delivery (POD)

A location that the Transmission Service Provider specifies on its transmission system where an interchange transaction leaves or a Load-Serving Entity receives its energy.

2.17. Point of Receipt (POR)

A location that the Transmission Service Provider specifies on its transmission system where an interchange transaction enters or a generator delivers its output.

2.18. Power Transfer Distribution Factor (PTDF)

In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer.

2.19. System Operating Limit (SOL)

The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility ratings (applicable pre- and post-contingency equipment or facility ratings)
- Transient stability ratings (applicable pre- and post-contingency stability limits)
- Voltage stability ratings (applicable pre- and post-contingency voltage stability)

- System voltage limits (applicable pre- and post-contingency voltage limits)

2.20. Total Flowgate Capability (TFC)

The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

2.21. Transfer Distribution Factor (TDF)

The portion of an interchange transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).

2.22. Transmission Owner

The entity that owns and maintains transmission facilities.

2.23. Transmission Reliability Margin (TRM)

The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

2.24. Transmission Service

Services provided to the transmission customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

2.25. Transmission Service Provider (TSP)

The entity that administers the transmission tariff and provides Transmission Service to transmission customers under applicable Transmission Service agreements.

3. Overview

Duke Energy Carolinas has chosen to use the Flowgate Methodology for calculating AFCs and the resultant ATCs for each ATC Path.

The Flowgate Methodology is based on the assumption that certain elements on the transmission system will begin to reach their limits before the other elements on the system. Therefore by monitoring these more sensitive areas on the transmission system, transfer capability calculations can be simplified in regard to the number of contingencies and monitored elements examined during each study. This allows for a greater number of studies to be conducted with simplified input assumptions. The resulting studies focus on how power would actually flow if the Transmission Service requests were to be approved.

The Flowgate Methodology involves the calculation of AFC on Flowgates modeled in the process. ATC on posted paths is then derived from the calculated AFCs.

4. Two-Part AFC Calculation Process

Duke Energy Carolinas' AFC calculation takes place as a two part process:

1. Model Building Process - Duke Energy Carolinas utilizes commercially available model building software for its model building process. This tool utilizes a starting point case that is used to derive multiple powerflow snapshot models covering defined horizons. From these snapshot models, Flowgate baseflows and GSFs relative to a reference bus are calculated.

2. AFC Calculation Process - The Flowgate baseflows and GSFs are then passed to an AFC engine. The transaction TDF values are computed from the GSF values by subtracting the load GSF from the source GSF. The AFC Engine is a suite of software applications that determines Transmission Service reservation impacts, calculates AFCs and ATCs, evaluates new Transmission Service requests, applies business rules, and posts ATCs on OASIS.

5. AFC Calculation Horizons and Frequency

Duke Energy Carolinas has identified three distinct horizons for the calculation of AFC and ATC: Operating, Planning, and Study. The AFC calculation horizons are defined as follows:

AFC Time Horizon	AFC Horizon Time Range
Operating	Prior to 10:00 AM EPT, current hour - midnight of the current day. After 10:00 AM EPT, current hour - midnight of the next day
Hourly Planning	End of Operating horizon - at least 6 days beyond the current day
Daily Planning	End of Hourly Planning horizon - at least 31 days beyond the current day
Monthly Study	End of Daily Planning horizon - at least 13 calendar months from current month

Duke Energy Carolinas' two-part AFC calculation process is executed at regularly scheduled intervals via automated processes. These automated processes create hourly, daily, and monthly models and derive TDFs and AFCs from those models at the following frequency:

Increment	Model Build & AFC Calculation Frequency*
Hourly	Next 48 hours calculated hourly Next 168 hours (at least) calculated daily
Daily	Next 31 days (at least) calculated daily
Monthly	Next 13 months (at least) calculated daily

*Timeframes indicate when the models are built and new AFC values are calculated from these models. AFCs and resulting ATCs, however, are continuously decremented as Duke Energy Carolinas' Transmission Service reservations are confirmed.

6. Flowgate Identification

Flowgates are identified by one of several methods:

- Flowgates identified as part of coordination agreements
- Flowgates requested for inclusion by another TSP
- Flowgates subject to interconnection-wide congestion management procedure within the last twelve months
- Flowgates identified by screening tests

6.1. Flowgates Identified As Part of Coordination Agreements

Duke Energy Carolinas includes Flowgates to support coordination agreements.

6.2. Flowgates Requested For Inclusion by Another TSP

If another TSP asks Duke Energy Carolinas to include in its AFC process Flowgates that fall outside Duke Energy Carolinas' TSP area, the Flowgate must be included in the requesting TSP's methodology, and the Flowgate must pass screening tests:

- Any generator within Duke Energy Carolinas' TSP area has at least a 5% PTDF or OTDF impact on the Flowgate when delivered to the aggregate load of Duke Energy Carolinas' TSP area, or
- A transfer from Duke Energy Carolinas' TSP area to an adjacent BA Area has at least a 5% PTDF or OTDF impact on the Flowgate.

To help manage the NC/PJM interface, lower cutoff PTDFs and OTDFs may be employed. The NC/PJM interface consists of the interfaces between the PJM BA Area and the three BA Areas on the North Carolina border with PJM: Duke Energy Carolinas, Carolina Power & Light East, and Carolina Power & Light West.

6.3. Flowgates Subject to Interconnection-Wide Congestion Management Procedure Within the Last Twelve Months

Duke Energy Carolinas will include any Flowgate within its Reliability Coordinator area that has been subjected to an interconnection-wide congestion management procedure within the last twelve months, unless the Flowgate was created to address temporary operating conditions.

6.4. Flowgates Identified By Screening Tests

Screening tests identify Flowgates that are not addressed by the aforementioned methods. These screening tests identify Flowgates that fall inside Duke Energy Carolinas' TSP area (internal Flowgates) as well as Flowgates that fall outside Duke Energy Carolinas' TSP area (external Flowgates).

Flowgates identified by screening tests are based, at a minimum, on the results of first contingency transfer analyses from adjacent BA source and sink combinations up to the path capability such that at least the first three limiting Elements and their worst associated contingency combinations with an OTDF of at least 5% are included.

7. Databases for AFC Processes

A collection of data exists for both the model building process and the AFC calculation process.

The database for the model building process includes all input and output data such as load forecasts, generation outages, transmission outages, generation block dispatch files, Flowgate definitions, POR/POD definitions, tagging data from Tag Dump, starting point models, output models, GSFs, and Flowgate baseflows.

The database for the AFC calculation process (the AFC Engine) includes input and output data items such as Flowgate definitions, GSFs, Flowgate baseflows, Transmission Service requests, Transmission Service reservations, tags, TFCs, TRMs, CBMs, Contract Path Limits, counterflow percentages, calculated AFCs, external AFCs (AFC overrides), ATCs, and Remaining Contract Path Capabilities.

8. Assumptions in the AFC Process

8.1. Generation Dispatch

Priority or block dispatch files for the Duke Energy Carolinas TSP area and for adjacent TSP areas when available are used to dispatch the generation to meet the area load and scheduled interchange requirements. For other external areas, if a priority or block dispatch is not used, then the generation dispatch in the starting point case is used and on-line generation is scaled to balance the load, interchange, and losses.

8.2. Load Forecasts

Load forecast data from the System Data Exchange (SDX) is used when available for modeling load in the Duke Energy Carolinas TSP area and adjacent TSP areas. Load in the starting point cases is used for the remaining areas.

8.3. Transmission and Generation Outages

Transmission and generation outages from the SDX are used to model topology information for AFC calculations. Duke Energy Carolinas' AFC process takes into consideration transmission and generation outages for Duke Energy Carolinas TSP area and adjacent TSP areas.

8.4. Coordinated AFCs

For external Flowgates identified through AFC coordination, the AFCs that Duke Energy Carolinas calculates will be overridden by the AFCs provided by the TSP that calculates AFC for that Flowgate.

9. AFC Calculation Equations

9.1. Firm AFC Calculations

In accordance with the MOD-030 reliability standard, the following equation is employed when calculating firm AFC for a Flowgate for a specified period:

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + Counterflows_{Fi}$$

Where:

AFC_F is the firm AFC for the Flowgate for that period

TFC is the Total Flowgate Capability of the Flowgate

ETC_{Fi} is the sum of the impacts of existing firm Transmission Service commitments for the Flowgate during that period

CBM_i is the impact of the CBM on the Flowgate during that period

TRM_i is the impact of the TRM on the Flowgate during that period

$Postbacks_{Fi}$ are changes to firm AFC due to a change in the use of Transmission Service for that period

$Counterflows_{Fi}$ are adjustments to firm AFC due to power flows in the opposite direction of the Flowgate

9.2. Non-Firm AFC Calculations

In accordance with the MOD-030 reliability standard, the following equation is employed in calculating non-firm AFC:

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + Counterflows_{NFi}$$

Where:

AFC_{NF} is the non-firm AFC for the Flowgate for that period

TFC is the Total Flowgate Capability of the Flowgate

ETC_{Fi} is the sum of the impacts of existing firm Transmission Service commitments for the Flowgate during that period.

ETC_{NFi} is the sum of the impacts of existing non-firm Transmission Service commitments for the Flowgate during that period

CBM_{Si} is the impact of any CBM schedules on the Flowgate during that period

TRM_{Ui} is the impact of the unreleased TRM on the Flowgate during that period

$Postbacks_{NFi}$ are changes to non-firm AFC due to a change in the use of Transmission Service for that period

$Counterflows_{NFi}$ are adjustments to non-firm AFC due to power flows in the opposite direction of the Flowgate

9.3. Total Flowgate Capability

Duke Energy Carolinas utilizes summer and winter facility ratings. As such, TFCs used in the ATC calculation will reflect these seasonal ratings. In instances where there is a difference in derived limits, such as a tie line, the most limiting parameter is used when determining TFC.

TFCs will be established at least once per calendar year. If notified of a change in the facility rating by the Transmission Owner that would affect the TFC of a Flowgate used in the AFC process, the TFC will be updated within seven calendar days of the notification.

9.4. Existing Transmission Commitments

Flow impacts from committed uses of a TSP's transmission system are considered in the AFC calculation as ETC. For both firm and non-firm, ETC contains two major components: ETC_{model} and ETC_{AFC}. ETC_{model} is the impact of ETC accounted for in the model building process, and ETC_{AFC} is the impact of ETC accounted for in the AFC calculation process. Processes are in place to ensure that no double counting takes place between transmission commitment impacts accounted for in ETC_{model} and transmission commitment impacts accounted for in ETC_{AFC}.

$$ETC = ETC_{model} + ETC_{AFC}$$

9.4.1. ETC_{model} - All Horizons

For firm and non-firm AFC calculations in all horizons, the baseflows that are calculated from models created in the model building process are synonymous with ETC_{model}. ETC_{model} is calculated using the following:

1. The impacts of generation to load for the Duke Energy Carolinas TSP area. These values are calculated from:

   a. Load forecast for the time period being calculated, and

   b. Unit commitment and generation block dispatch, including all designated network resources needed to meet the forecast load.

2. The impact of generation to load for adjacent TSP areas. These values are calculated from:

   a. Load forecast for the time period being calculated, and

   b. Unit commitment and generation block dispatch.

3. The impact of generation to load for all other TSP areas. These values are calculated from the seasonal peak load forecast included in the Multiregional Modeling Working Group (MMWG) models, SERC Near-Term Study Group (NTSG) models, or IDC models.

4. The impact of firm Network Integration Transmission Service (NITS) modeled in the starting point case for all BA Areas in the transmission model.

5. The impact of confirmed firm Point-to-Point (PTP) Transmission Service that are modeled in the starting point case for all BA Areas in the transmission model.

6. The impact of any grandfathered firm obligations that are modeled in the starting point case for all BA Areas in the transmission model.

7. Non-firm hourly AFC calculations in the operating horizon include the additional component of tag impacts from Tag Dump. Tag impacts include confirmed tags from the Duke Energy Carolinas TSP area and adjacent TSP areas and are filtered to ensure that no

double counting takes place between the reservation impacts and tag impacts in the model.

9.4.2. Firm $ETC_{AFC\text{-}Fi}$ - All Horizons

For firm AFC calculations in all defined horizons, the remaining ETC impacts are captured by $ETC_{AFC\text{-}Fi}$ in the AFC calculation process. $ETC_{AFC\text{-}Fi}$ is calculated using the following:

1. The impact of firm NITS for the Duke Energy Carolinas TSP area and adjacent TSP areas for which reservations are exchanged and which are not included in the model. The reservations from adjacent TSPs are filtered to ensure that no double counting takes place.

2. The impact of confirmed firm PTP Transmission Service expected to be scheduled for the Duke Energy Carolinas TSP area and adjacent TSP areas for which reservations are exchanged and which are not included in the model. The reservations from adjacent TSPs are filtered to ensure that no double counting takes place.

3. The impact of any grandfathered firm obligations expected to be scheduled or expected to flow for adjacent TSP areas for which reservations are exchanged and which are not included in the model. The reservations from adjacent TSPs are filtered to ensure that no double counting takes place. Duke Energy Carolinas no longer has any grandfathered firm obligations.

9.4.3 Non-Firm $ETC_{AFC\text{-}NFi}$

9.4.3.1. Non-Firm $ETC_{AFC\text{-}NFi}$ - Operating Horizon

For non-firm AFC calculations in the operating horizon, $ETC_{AFC\text{-}NFi}$ = zero, i.e., there are no additional ETC impacts beyond what is included in the model. This approach effectively releases unscheduled firm transmission to the non-firm market.

9.4.3.2. Non-Firm $ETC_{AFC\text{-}NFi}$ - Planning and Study Horizons

$ETC_{NFi\text{-}AFC}$ in the planning and study horizons is calculated using the following:

1. The impact of non-firm NITS (secondary service) for the Duke Energy Carolinas TSP area and adjacent TSP areas for which reservations are exchanged. The reservations from adjacent TSPs are filtered to ensure that no double counting takes place.

2. The impact of confirmed non-firm PTP Transmission Service expected to be scheduled for the Duke Energy Carolinas TSP area and adjacent TSP areas for which reservations are exchanged. The reservations from adjacent TSPs are filtered to ensure that no double counting takes place.

3. The impact of any grandfathered non-firm obligations expected to be scheduled or expected to flow for adjacent TSP areas for which reservations are exchanged. The reservations from adjacent TSPs are filtered to ensure that no double counting takes place. Duke Energy Carolinas has no grandfathered non-firm obligations.

9.4.4. Transmission Service Request Rollover Rights Impact

Transmission Service reservations that have met the requirements for rollover service are considered as impact in the ETC_{AFC} calculation for the time periods when the rollover would occur.

9.5. Counterflows

When applying transmission reservation impacts in the opposite direction of flow on a Flowgate in the AFC calculations, counterflow assumptions are used. Counterflow impact percentages are defined for each Flowgate and address:

- Firm reservation counterflow impact on firm AFC calculations
- Firm reservation counterflow impact on non-firm AFC calculations
- Non-firm reservation counterflow impact on non-firm AFC calculations

Counterflow assumptions are based on operating experience of normal Flowgate flows. At times, a Flowgate may experience higher or lower than normal counterflows. If real-time or expected operating conditions change to the extent that higher or lower than normal counterflows are expected, the counterflow assumptions for the Flowgate can be changed to reflect the new conditions. Counterflow assumptions are reflected in the AFC process as a Flowgate attribute.

9.6. Postbacks

The postback component of the AFC equation is implicit in the ETC_{AFC} component. Changes in reservation status are captured in the AFC Engine and are incorporated into the AFC values.

9.7. Capacity Benefit Margin (CBM)

Duke Energy Carolinas has not defined a need for CBM on any of its interfaces in the Operating, Planning, or Study Horizons. As such, the importing and exporting CBM on all interfaces is set to zero.

Duke Energy Carolinas does not address generation reliability assessments through the utilization of CBM, so this document does not contain the methodology and assumptions that Duke Energy Carolinas uses for generation reliability requirements.

9.8. Transmission Reliability Margin

Duke Energy Carolinas participates in a reserve sharing agreement with Carolina Power & Light Company, South Carolina Electric & Gas Company, South Carolina Public Service Authority, and Virginia Electric and Power Company. This agreement requires that each participating company provide a contingency reserve commitment to the other participants. Each participating company is required to maintain their share of the total contingency reserve based on a formula that takes into account each company's annual peak demand and largest resource.

Duke Energy Carolinas allocates TRM across its ATC Paths based on contractual obligations to supply and receive operating reserves. Currently, the only contractual obligation Duke Energy Carolinas has is with the participants of the reserve sharing agreement as stated above. The contractual requirements for the reserve sharing participants are reviewed, established, and updated on an annual basis. Duke Energy Carolinas allocates these contractual obligations to its ATC Paths through the utilization of TRM, based on the following methodology:

- Imports - TRM for ATC Paths sinking in the Duke Energy Carolinas BA Area from participating BA Areas is set to the opposing BA Area's share of the reserve requirement. TRM on ATC Paths sinking in the Duke Energy Carolinas BA Area from non-participating BA Areas is set to zero, until such time as contingency reserves are identified and contracts have been established for those interfaces.

- Exports - TRM for ATC Paths sourcing from the Duke Energy Carolinas BA Area to participating BA Areas is set to Duke Energy Carolinas' share of the reserve requirement. TRM on ATC Paths sourcing from the Duke Energy Carolinas BA Area to non-participating BA Areas is set to zero, until such time as contingency reserves are identified and contracts have been established for those interfaces. It should be noted that the TRM for exports to Carolina Power & Light are split between CPLE and CPLW.

Note that imports/exports from/to Virginia Electric and Power Company are scheduled through the CPLE BA Area.

Duke Energy Carolinas' TRM is based on reserve sharing requirements. In order to account for the TRM in the AFC process, it is necessary to convert the reserve sharing requirements on the interfaces to Flowgate-based values. The conversion process simulates the import and export of the full amount of the reserves to and from each of the reserve sharing agreement participants. The worst impact on each Flowgate determines the TRM amount allocated to that Flowgate. These Flowgate-based TRM values will be re-established when the path-based reserve sharing TRM amounts are recalculated. Additionally, the Flowgate-based TRM values will be established for any Flowgate added to the transfer capability calculation process.

10. ATC Calculation

10.1. Converting AFC to ATC

When converting AFCs to ATCs, the following equations are used:

$$ATC_{AFC} = \min(P)$$

$$P = \{PATC_1, PATC_2, \dots PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}}$$

Where:

ATC_{AFC} = the ATC derived from the AFC process

P = is the set of partial ATCs for all impacted Flowgates honored by Duke Energy Carolinas

$PATC_n$ = the partial ATC for a path relative to a Flowgate *n*

AFC_n = the AFC for Flowgate *n*

DF_{np} = the distribution factor for Flowgate *n* relative to path *p*

10.2. Contract Path Limit

The interface between Duke Energy Carolinas' transmission system and that of adjacent BA Areas is considered to be an import/export path. Each import and export path is associated with a Contract Path Limit. This Contract Path Limit is the minimum of:

- The sum of the ratings of the ties
- The maximum transfer expected to occur on the import or export path. This value is based on traditional transfer test levels.

Duke Energy Carolinas' ATC calculation takes into consideration Contract Path Limits. This is accomplished by calculating Remaining Contract Path Capability

(RCPC) for import and export paths in parallel with the AFC process. RCPC on import and export paths is calculated according to the following formula:

$$RCPC_p = Contract\ Path\ Limit_p - \sum Reservations\ or\ Schedules_p$$

Where:

$RCPC_p$ = The Remaining Contract Path Capability on import or export path *p*

Contract Path Limit$_p$ = The Contract Path Limit on import or export path *p*

Reservations or Schedules$_p$ = Reservations or Schedules (depending on the horizon) reserved or scheduled on import or export path *p*

RCPC for an import or export path is decremented based on the POR/POD of the reservation or schedule, and these reservations/schedules, whether firm or non-firm, are not netted. In other words, a reservation or schedule on the export path "Duke-to-Neighbor A" does not impact the RCPC for the import path "Neighbor A-to-Duke", and vice versa.

Pass-through reservations/schedules decrement two separate import/export paths - the import path from the POR and the export path to the POD. The RCPC used in the evaluation of a pass-through Transmission Service request is the lesser of the RCPC on the corresponding import and export path.

10.3. ATC on Posted Paths

When determining $ATC_{posted\ path}$, the following equation is used:

$$ATC_{posted\ path} = min[ATC_{AFC}, RCPC_p]$$

Where:

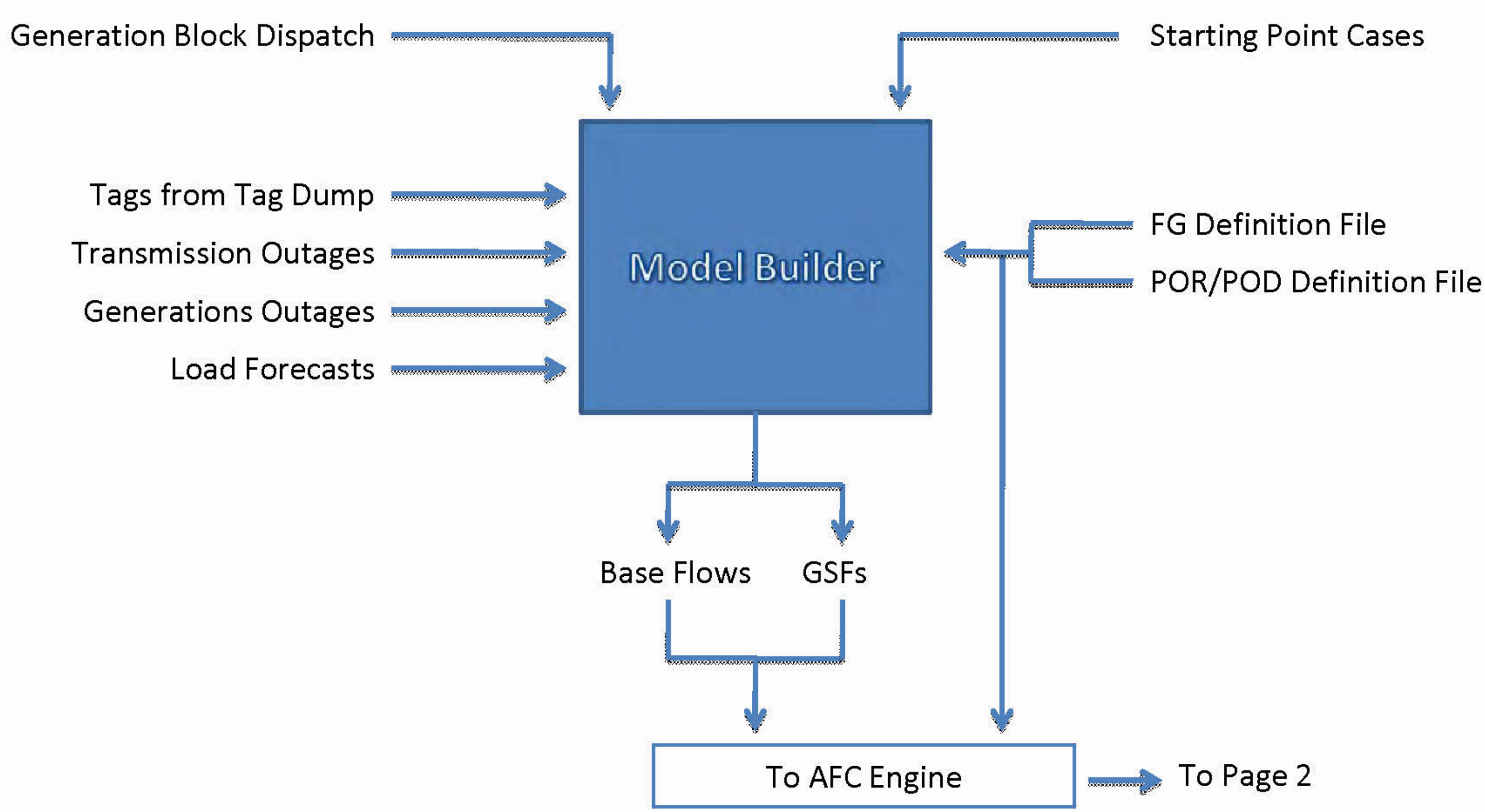
$ATC_{posted\ path}$ = the Available Transfer Capability for that path that is posted on OASIS

ATC_{AFC} = the ATC for that posted path derived from the AFC process

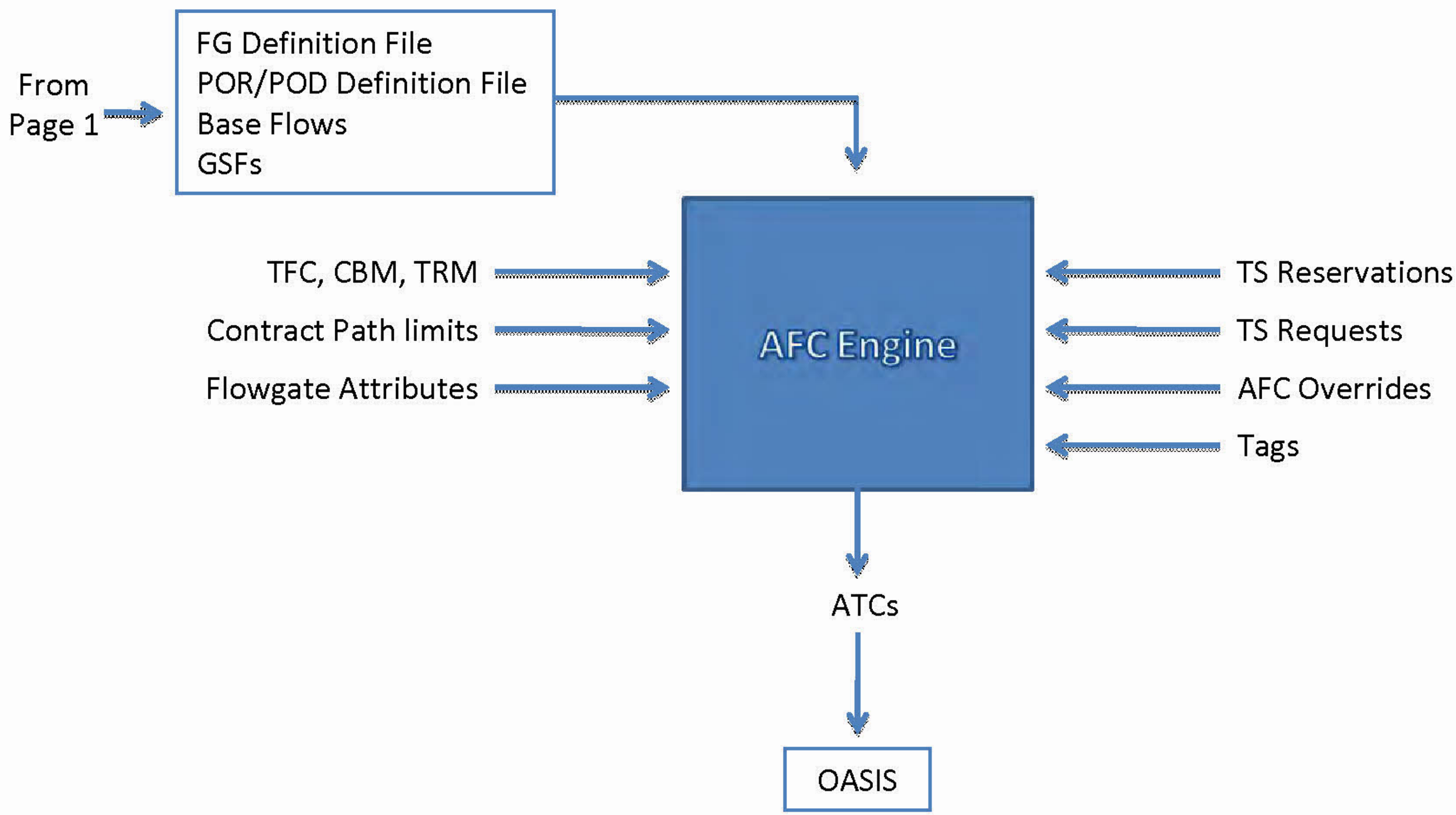
$RCPC_p$ = Remaining Contract Path Capability for the applicable import/export path *p*

11. Process Flow Diagrams

ATC Process Flow



ATC Process Flow



ATTACHMENT D

~~**Methodology for Completing a System Impact Study**~~

METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY

A. CP&L Zone

Upon receipt of an executed System Impact Study Agreement, CP&L will perform studies using its power flow models to identify any system constraints resulting from the requested service. Using these models, CP&L evaluates its present and planned transmission system for conformance to its Transmission Planning Criteria and Assessment Practices. These Transmission Planning Criteria and Assessment Practices, which CP&L uses to evaluate System Impact Study requests, are filed annually in FERC Form No. 715, "Annual Transmission Planning and Evaluation Report." CP&L will use the same procedure, assumptions and criteria in performing a System Impact Study for an Eligible Customer as it uses when performing studies for its own uses of the Transmission System.

CP&L will notify the Eligible Customer upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. Within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or the Application will be deemed terminated and withdrawn.

If the System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, CP&L, within thirty (30) days of completion of the System Impact Study, will tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer must agree to reimburse CP&L for performing the required Facilities Study. Upon receipt of an executed Facilities Study Agreement, CP&L will use due diligence to complete the required Facilities Study within a sixty (60) day period.

CP&L will use due diligence to complete the required System Impact Study within a sixty (60) day period. In the event that CP&L is unable to complete the required System Impact Study within such time period, CP&L will so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies.

B. FPC Zone

The Transmission Provider will evaluate the impact of a prospective firm transmission transaction by modeling the transaction using an applicable transmission system electrical model. This evaluation will consider the following:

- The Transmission Provider's reliability criteria.
- Current and reasonably forecasted loads of the Transmission Provider's Native Load Customers and Network Integration Transmission service customers on the Transmission Provider's transmission system.
- Pending and existing firm transmission transactions that coincide with the time requested for the prospective transaction, modeled on a simultaneous basis.

Analysis will involve using the appropriate transmission system electrical model in a load flow and/or transient stability program to model normal and various first contingency situations that may occur, and determining whether system response meets acceptable criteria considering the prospective transaction. In general, this involves running simulations for the loss of any single line, generator, or transformer, with any one generator scheduled out for maintenance. The Transmission Provider will normally run this transmission system analysis from minimum to peak load conditions for possible contingencies. If appropriate, additional studies would be performed to determine transmission system response to less probable contingency criteria, to assure the system meets Transmission Provider, FRCC and SERC planning guidelines for more severe outages. These studies would include the loss of multiple generators or lines and combinations of each. These less probable scenarios are also evaluated at various load levels, since some of the most severe situations occur at average or minimum load conditions. In particular, critical fault clearing times are typically the shortest (most severe) at minimum load conditions, with just a few large base load units supplying the system needs. For more detail on the Transmission Provider's planning criteria please refer to the most current FERC Form No. 715 "*Annual Transmission Planning and Evaluation Report*" on file with the FERC.

The Transmission Provider also will evaluate the impact of a prospective firm transaction on the critical Transmission Provider interfaces. Transfer analysis will be conducted in accordance with the NERC reference document for calculating and reporting the electric power transfer capability of interconnected electric systems titled *Transmission Transfer Capability,* dated May 1995, as amended or supplemented from time to time. This transfer analysis will consider the simultaneous effect of all existing and pending firm power transactions of the Transmission Provider's system with the prospective transaction simulated at the same time. The amount of electric power, incremental above normal base power transfers, that can be transferred over the Transmission Provider's Transmission System in a reliable manner will be based on all of the following criteria:

- For the existing or planned system configuration under normal conditions, all facility loadings will be within normal ratings and all voltages within normal limits.
- The Transmission Provider's Transmission System should be capable of absorbing the dynamic power swings and remaining stable following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit.

- After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described above, all transmission facility loading should be within emergency ratings and all voltages should be within emergency limits.

The prospective transaction will also be evaluated in term of impact on other major interfaces in which the Transmission Provider has obligations to abide by defined procedures. As an example, transfer limit studies for the Florida-Georgia transmission Interface have very specific procedures that have been agreed to by FRCC utilities. These procedures and the currently accepted limits can be obtained from the FRCC and must be followed to assure reasonable results. Failure to follow the recommended methodology will result in overly optimistic reactive reserves, and thus optimistic transfer limits.

C. DEC Zone

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will perform studies using power flow, transfer, stability, fault and other analyses as necessary and appropriate to determine whether sufficient transmission capability is available and to identify any system constraints resulting from the requested transmission service. More detailed criteria and processes utilized by the Transmission Provider in performing a System Impact Study are set forth in the Transmission Provider's annual FERC Form No. 715 submittal. The Transmission Provider will use the same study approach in completing the studies for a Transmission Customer as it uses when completing such studies for itself.

The Transmission Provider subscribes to all applicable North American Electric Reliability Council (NERC) and Southeastern Electric Reliability Council (SERC) Transmission Reliability criteria for both its own transmission system studies and System Impact Studies. Specifically, the Transmission Provider subscribes to NERC's Transmission Transfer Capability document and SERC's Planning Principles and Guides. In addition, the Transmission Provider subscribes to its own Reliability Guidelines for its own transmission system studies and System Impact Studies.

The Transmission Provider's Reliability Guidelines are established to ensure that the Transmission Provider's transmission network is capable of moving power throughout its system while maintaining acceptable voltage and thermal loading levels, during both normal and contingency conditions. The Reliability Guidelines, which are filed with FERC as part of the FERC Form No. 715, include transmission planning objectives, planning assumptions, study practices, and planning guidelines.

ATTACHMENT E

~~**Index Of Point-To-Point Transmission Service Customers**~~

INDEX OF POINT-TO-POINT TRANSMISSION SERVICE CUSTOMERS

See Transmission Provider's Electric Quarterly Report at the following Internet address:

<http://www.ferc.gov/docs-filing/eqr/data/spreadsheet.asp>

ATTACHMENT F- 1

FORM OF SERVICE AGREEMENT FOR NETWORK INTEGRATION TRANSMISSION SERVICE
(CP&L ZONE AND FPC ZONE)

~~**Form of Service Agreement For**~~

~~**Network Integration Transmission Service**~~

1.0 This Service Agreement, dated as of _______________, is entered into, by and between Carolina Power & Light Company/Florida Power Corporation (the Transmission Provider), and ____________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Network Integration Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in the amount of $_________, in accordance with the provisions of Section 29.2 of the Tariff or has met the creditworthiness standards of Attachment ~~L~~O of the Tariff. In the event that the Customer does not take service for any reason, the Transmission Provider will return the deposit, with interest at the rate specified in 18 C.F.R. § 35.19a(a) (2)(iii), less any costs the Transmission Provider incurred in processing the Application (including, where necessary, the performance of a System Impact Study; the Transmission Provider will provide the Applicant with a statement identifying the costs incurred.

4.0 Service under this agreement shall commence on the later of (1) __________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this Service Agreement shall terminate on ______________________.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Network Integration Transmission Service in accordance with the provisions of Part III of the Tariff and this Service Agreement.

5.1 The Transmission Customer is responsible for replacing Real Power Losses associated with all transmission service in accordance with Section 28.5 of the Tariff. The Transmission Customer must identify the party responsible for supplying Real Power Losses before the transaction.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

The remaining pages to Attachment F-1
contain no changes of substance and are not included.

ATTACHMENT ~~G~~F- 2

FORM OF SERVICE AGREEMENT FOR NETWORK INTEGRATION TRANSMISSION SERVICE (DEC ZONE)

OATT SERVICE AGREEMENT NO. XXX

SERVICE AGREEMENT

FOR

NETWORK INTEGRATION TRANSMISSION SERVICE

BETWEEN

DUKE ENERGY CAROLINAS, LLC

AND

CUSTOMER

Service Agreement For
Network Integration Transmission Service

1.0 PARTIES

This Service Agreement, dated as of September 1, 2006, amended as of October 1, 2006, February 1, 2008 and January 1, 2011 is entered into, by and among Duke Energy Carolinas, LLC (the "Transmission Provider"), and Customer a state Corporation ("XXXX") ("Transmission Customer") sometimes hereinafter referred to individually as "Party" and collectively as "Parties."

2.0 COMPLETED APPLICATION

The Transmission Customer has been determined to have a Completed Application for Network Integration Transmission Service under the Transmission Provider's Open Access Transmission Tariff (the "Tariff").

If the corporate identity or name of XXXX is to change during the term of this Service Agreement, XXXX shall notify Transmission Provider as soon as possible after learning of said projected change. In such event Transmission Provider may in its reasonable discretion require a new Application for Network Integration Transmission Service and/or the execution of an appropriate amendment of this Service Agreement.

3.0 TERM

Unless the Federal Energy Regulatory Commission (the "Commission") orders a different date for commencement of service, service under this Service Agreement shall commence on the later of: (1) the date the conditions precedent to receiving service set forth in Section 29.1 of the Tariff are met, or (2) September 1, 2006. Service under this Service Agreement shall continue through [DATE]. If the Service Agreement is not terminated by the Transmission Provider or the Transmission Customer, the Service Agreement will automatically renew for successive five year terms. The Service Agreement may be terminated at the end of each successive five year term by the Transmission Provider or the Transmission Customer by giving notice of such termination in writing at least one year prior to the end of the renewal period.

4.0 EFFECT OF ISO/RTO PARTICIPATION

This Service Agreement and the Network Operating Agreement, and the attachments thereto (collectively, the "Subject Agreements"), have been developed by the Parties in the context of transmission service provided pursuant to the Tariff and the Commission's open access requirements under Order No. 888 during a period of regulatory transition. The Parties acknowledge that the Transmission Provider is likely to join a Regional Transmission Organization ("RTO"), and further acknowledge that at such time as the Transmission Provider does so join an RTO transmission service shall be provided to the Transmission Customer pursuant to the rates, terms and conditions of the open access transmission tariff of the RTO ("RTO OATT"), and other terms, conditions, rules and/or protocols of the RTO. The Parties further agree that in the event of a material inconsistency or conflict between the RTO OATT or such other terms, conditions, rules and/or protocols of the RTO and the Subject Agreements, that the Subject Agreements may require amendment to account for such changed circumstance. In such event, at the request of either Party or the RTO, the Transmission Customer and the RTO (and the Transmission Provider, if appropriate) shall enter into good faith negotiations to amend the Subject Agreements in a manner such that the transmission service is provided in accordance with the RTO OATT and such other terms, conditions, rules and/or protocols. If the Transmission Customer and the RTO (and the Transmission Provider if appropriate) cannot agree on the necessary revisions the Transmission Customer may request that the RTO (and the Transmission Provider, if appropriate) file unexecuted amended Subject Agreements with the Commission pursuant to Section 205 of the Federal Power Act such that the transmission service thereunder comports with the RTO OATT and such other terms, conditions rules and/or protocols of the RTO and the Transmission Provider shall support the Transmission Customer's right to request such filing. By agreeing to the procedure set forth above, neither Party waives any rights it might otherwise have with respect to the Subject Agreements under the Federal Power Act.

5.0 NATURE OF SERVICE TO BE FURNISHED

The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Network Integration Transmission Service in accordance with the provisions of Part III of the Tariff and this Service Agreement, the Attachments hereto, and the Network Operating Agreement as they may be amended from time to time. Neither Party shall be deemed, by virtue of having entered into this Service Agreement, to have agreed to diminish or enhance the rights of either Party with regard to the Commission's comparability policies, provided that the foregoing clause shall be construed in a manner most consistent with each Party performing its obligations hereunder.

6.0 NOTICES

Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Duke Energy Carolinas, LLC
526 South Church Street
Mailcode: EC02A
Charlotte, NC 28201-1006
Attn: Charlotte Glassman
Transmission Contracts Manager
Phone: (704) 382-3621
Fax Number: (704) 382-0850
E-Mail Address: caglassm@duke-energy.com

Transmission Customer:

[Customer]
Address

Attn:
Title:
Phone:
Fax:
E-Mail Address:
Bills for Service hereunder shall be sent to:
With copy to:

7.0 INCORPORATION OF OTHER DOCUMENTS

The Tariff, Attachment A hereto (Specifications for Network Integration Transmission Service), Attachment B hereto (Delivery Points), Attachment C hereto (Distribution Rates), Attachment D hereto (Power Factor Penalty), Attachment E hereto (Network Operating Agreement), and Attachment F hereto (Other Charges) are incorporated herein and made a part hereof.

To the extent that any provisions in the Tariff, this Service Agreement (including Attachments) or the Network Operating Agreement are ambiguous or inconsistent, any such ambiguity or inconsistency will be resolved in the following priority: the Tariff, the Service Agreement (including Attachments).

8.0 BILLINGS AND BILLING ADJUSTMENTS

8.1 The Transmission Provider will have the right to adjust or revise any bill rendered under the Tariff no later than eighteen (18) months after the date the bill was rendered. Any billing adjustment will be in writing and will state the specific basis for the adjustment. An Adjusted Bill will constitute a new bill in regard to the adjusted components for all purposes of the Tariff and this Service Agreement.

8.2 The Transmission Customer may, in good faith, challenge the correctness of any bill and any adjusted or revised bills. The Transmission Customer's challenge of any bill rendered under the Tariff may include the appropriateness of all charges thereunder. Unless otherwise agreed in writing by the Parties, the Transmission Customer's challenge must be presented no later than eighteen (18) months following the date such bill is received. Any billing challenge will be in writing and will state the specific basis for the challenge. The Transmission Provider shall respond in writing to any such billing challenge within forty-five (45) days. After such response, billing challenges shall be treated as disputes pursuant to Section 7.3 of the Tariff.

8.3 Refunds or additional charges that are a result of an adjustment, revision or billing challenge will include interest calculated at the rate set forth in 18 C.F.R. § 35.19a (a)(2)(iii).

9.0 AUDITS

9.1 In addition to the bill challenge rights set forth in Section 8.2, the Transmission Customer shall also have audit rights as set forth in this Section 9.0. The Transmission Customer shall conduct any such audit within eighteen (18) months from the date of the rendering of any bill under the Tariff. The Transmission Provider and the Transmission Customer will each have the right, upon reasonable notice, to inspect or audit each other's accounts and records supporting the bills for service under the Tariff during such calendar year. Such audit will be performed to the extent necessary to verify the correctness of any bill and the appropriateness of all charges thereunder. The audited Party shall provide or cause to be provided all information that the auditing Party may reasonably request to substantiate all billings, adjustments or revisions to billings for service under the Tariff. Any such audit will be conducted, upon reasonable written notice, during normal business hours at the offices where such accounts and records are maintained or at a location mutually agreeable to the Parties. The audited Party shall provide to the auditing Party reasonable office accommodations to conduct the audit. Those qualified personnel identified upon reasonable written notice by the auditing Party will be permitted to conduct audits. The audited Party will be entitled to review the audit report and any supporting materials at the conclusion of the audit and prior to finalization. The accounts and records for any particular billing period shall not be subject to more than one (1) audit by each Party.

9.2 Notwithstanding the above, if the Transmission Provider renders a billing adjustment or revision and the audit for the affected calendar year has been conducted, then the Transmission Customer may conduct an audit of the billing adjustment or revision within ninety (90) days after the adjustment is rendered and challenge such adjustment no later than one-hundred and fifty (150) days after the adjustment is rendered.

9.3 With the exception of quantifiable changes in the amounts of the billings, the audit report, supporting materials, and all other audit results of all such audits shall be kept confidential by the Parties and shall not be released to any other party without the express written consent of the other Party except that in the event that a matter subject to audit becomes the subject of dispute resolution or litigation in any forum with jurisdiction, a Party may disclose to the decision maker the audit report, supporting materials, other audit results of all such audits, and any related information, provided that the other Party is afforded notice and an opportunity to request that such information be protected against disclosure to third parties.

10.0 DELIVERY POINTS

The Transmission Customer Delivery Points shall be the points of connection between the Transmission Provider's facilities and the facilities of the Transmission Customer or its member systems.

11.0 ADJUSTMENT FOR LOSSES

To the extent any Delivery Point is at a voltage level less than 44 kV or the metering point(s) is (are) remote from the Delivery Point, the load associated with such Delivery Point used for the calculation of the Network Integration Transmission Service charge shall be adjusted for the losses associated with: (i) the Transmission Provider's applicable distribution facilities losses; and/or (ii) the Transmission Customer's distribution and transmission facilities, as applicable. Such loss compensation factors shall be as mutually agreed upon by the Parties. To the extent the Parties cannot agree on any such factors, the Dispute Resolution Procedures in Section 12 of the Tariff may be invoked to resolve the disagreement.

12.0 NO WAIVERS

Failure of a Party to enforce any provision of this Service Agreement will not be construed as a waiver of such provision, and will not affect the validity of the Service Agreement or the right of either Party subsequently to enforce any provision of the Service Agreement. Any waiver at any time by either Party of its rights with respect to the other Party or with respect to any matter arising in connection with this Service Agreement will not be considered a waiver with respect to any subsequent matter. Failure of a Party to resort to any legal remedy or to exercise any one or more alternative remedies will not affect such Party's right subsequently to resort to any one or more of such rights or remedies on account of any such grounds then existing or which may subsequently occur.

13.0 RUS APPROVAL

This Service Agreement and any subsequent amendment(s) are subject to the approval of the Administrator of the Rural Utilities Service ("RUS"). The Transmission Customer will be responsible for obtaining approval of this Service Agreement from the RUS and will seek to obtain such approval promptly. If the RUS fails to approve either in whole or in part this Service Agreement or any subsequent amendments as submitted, the Parties will undertake to renegotiate this Service Agreement or said amendments, as appropriate, to restore this Service Agreement as near as possible to its original intent and effect, provided that by virtue of such renegotiation no party shall be obligated to agree to the insertion of, deletion of or modification of any specific provisions of this Service Agreement.

14.0 ACCEPTANCE BY FERC

The Parties recognize that this Service Agreement and its Attachments must be filed with the Federal Energy Regulatory Commission and is subject to the jurisdiction of that Commission. This Service Agreement is conditioned expressly on acceptance by the Commission of this Service Agreement and its Attachments without changes or conditions unacceptable to either Party. The Parties agree that in the event that any of the terms and conditions of this Service Agreement and its Attachments are finally held or determined to be invalid, illegal or void, or to be in contravention of any applicable laws, rules, regulations or public policy, all other terms and conditions of this Service Agreement and its Attachments shall remain in full force and effect unless the terms and conditions so found to be invalid, illegal or void are not reasonably separable from the remaining terms and conditions of this Service Agreement and its Attachments. The Parties further agree that if, upon the initial filing of this Service Agreement and its Attachments with the Commission or at any time thereafter, the Commission or a court of competent jurisdiction issues an Order that (i) amends, modifies or conditions this Service Agreement and its Attachments in a way that materially changes the obligations or benefits to either Party, or (ii) finds on a final basis any provision of this Service Agreement and its Attachments to be invalid, illegal or void, the Parties shall review such Order to determine whether such amendments, modification, conditions or findings are acceptable. Within twenty-one (21) calendar days following such Order, the Parties shall notify each other in writing of their acceptance or rejection of the Service Agreement and its Attachments based upon any amendments, modifications, conditions or findings so ordered. A failure by a Party to provide notification within such twenty-one (21) day period shall be deemed acceptance. If either Party provides notification of its rejection or such Order requires adjustment of this Service Agreement and its Attachments, the Parties shall enter into re-negotiation of this Service Agreement and its Attachments within 60 calendar days either after the notification or the Order for the purposes of restoring as nearly as possible the obligations and benefits of each Party as originally bargained for and conforming this Service Agreement and its Attachments with the requirements of such Order. If no agreement is reached by the Parties on the terms and conditions of a reformulated Service Agreement and Attachments within sixty (60) calendar days after the initiation of such re-negotiation, the Parties agree that the Transmission Provider shall file a proposed unexecuted Service Agreement and Attachments with the Commission no later than ninety (90) calendar days after the initiation of such re-negotiation.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

Duke Energy Carolinas, LCC (Transmission)

Signature: ________________________________

By: Jim L Stanley Sr. Vice President, Power Delivery ____________
Name Title Date

Transmission Customer

Customer

Signature: ________________________________

By: ____
Name Title Date

Attachment A
Specifications For
Network Integration Transmission Service

1.0 Term of Network Service:

As specified in Section 3.0 of the Service Agreement for Network Integration Transmission Service.

2.0 Description of Capacity and/or Energy to be Transmitted by Transmission Provider Across the Transmission Provider's Transmission System (including electric control area in which the transaction originates):

Firm capacity and energy delivered to the Transmission Provider's Transmission System in the amount of (i) the sum of hourly metered load(s) at the metering location, compensated, where applicable, for losses on (a) the Transmission Customer's facilities to the extent the metering is remote from the delivery point and (b) the Transmission Provider's distribution facilities to the extent such delivery point is served from such facilities, plus (ii) real power losses on the Transmission Provider's Transmission System as set forth in Section 28.5 of the Tariff. The listing of the Transmission Customer's Delivery Points, as may be amended from time to time, is set forth in Attachment B to the Service Agreement. Detailed information about each of the Transmission Customer's Delivery Points shall be set forth in Delivery Point Data Sheets, executed by the Parties, substantially in the form set forth in Attachment B to the Service Agreement.

3.0 Resources:

Note: Changes or additions to Network Resources to serve Transmission Customer load growth shall be treated as a "Designation of New Network Resources" pursuant to Section 30.2 of the Transmission Provider's Tariff.

3.1 Transmission Customer Contracted Generation:

3.2 Designated Network Resource

Control Area in Which Resource is Located:
Designated Interface(s): N/A

4.0 Network Load:

The Network Load is the demand and energy requirements of Transmission Customer's x number of Delivery Points connected or anticipated to be connected to the Transmission Provider's transmission and distribution system.

5.0 Designation of Party Subject to Reciprocal Service Obligation:

The Transmission Customer

6.0 Service Under This Agreement May be Subject to Some Combination of the Charges Detailed Below:

The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.

6.1 Transmission Charge:

As per the Tariff, Part III Section 34.

6.2 Facilities Study Charge:

Not Applicable

6.3 Direct Assignment Facilities Charge:

As per the Tariff and Commission's approval of directly assignable charges.

6.4 Ancillary Services Charge:

Schedule 1, Scheduling, System Control and Dispatch Service:
The charges for **Scheduling, System Control and Dispatch Service** are as provided per the Tariff, Schedule 1.

Schedule 2, Reactive Supply and Voltage Control from Generation Source Service**:**
The charges for **Reactive Supply and Voltage Control from Generation Sources Service** are provided per the Tariff, Schedule 2.

Schedule 3, Regulation and Frequency Response Service: The charges for **Regulation and Frequency Response Service** are provided per the Tariff, Schedule 3.

Schedule 4, Energy Imbalance Service: The Transmission Customer must either purchase **Energy Imbalance Service** from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligations. The charges for this service are as provided per the Tariff, Schedule 4.

Schedule 5, Operating Reserve - Spinning Reserve Service: The Transmission Customer must either purchase **Operating Reserve - Spinning Reserve Service** from the Transmission Provider or make alternative comparable arrangements to satisfy its Operating Reserve - Spinning Reserve Service obligations. The charges for this service are as provided per the Tariff, Schedule 5.

Schedule 6, Operating Reserve - Supplemental Reserve Service: The Transmission Customer must either purchase **Operating Reserve - Supplemental Reserve**

Service from the Transmission Provider or make alternative comparable arrangements to satisfy its Operating Reserve - Supplemental Reserve Service obligations. The charges for this service are as provided per the Tariff, Schedule 6.

6.5 Loss Compensation Service:

The Transmission Customer may elect to (1) supply the capacity and/or energy necessary to compensate the Transmission Provider for losses which occur across transmission facilities, (2) receive an amount of electricity at delivery points that is reduced by the amount of losses incurred by the Transmission Provider, or (3) with the concurrence of the Transmission Provider, have the Transmission Provider supply the capacity and/or energy necessary to compensate for such losses. To the extent the service is provided by the Transmission Provider, the charges for this service are as provided per the Tariff, Schedule 9.

6.6 Gross Receipts Tax:

The Transmission Customer has satisfied the Transmission Provider's requirement, if any, to provide documentation that the Transmission Customer's customers pay gross receipts taxes. The Transmission Provider will provide credits as appropriate.

6.7 Redispatch Charges:

As per the Tariff, Part III Section 34.4.

6.8 Distribution Rates:

As provided per the Tariff, Part III Section 34.6 and Attachment C-3.

6.9 Penalties for Non-Compliance with the Transmission Provider's Power Factor Standards:

As stated in Attachment D.

Attachment B

Delivery Points

Delivery Locations:

XXXX DELIVERY POINTS	DELIVERY PT NAME

Duke Energy Carolinas, LLC
Delivery Point Data Sheet

Transmission Customer Name: ______________________________

Member Name: ______________________________

Delivery Point Name Number: ______________________________

Delivery Identifier: ______________________________ ______________________________

Duke Energy Carolinas, LLC ***Transmission Customer***

Joint Use Substation: ______________

Delivery Point Location Description:

Planned Demand: ________ ***kW (Summer)*** ________ ***kW (Winter)***

Transmission Voltage: ________ ***kV*** ***Delivery Voltage:*** ________ ***kV***

Metered Voltage: ________ ***kV***

Meter Location: ______________________________

Meter Location Description:

Meter Ownership: ______________________________

Metering Compensation Description: ______________________________

Power Factor Grouping Number: ______________________________

Delivery Station Facilities:

Cost Basis: ________ ***Classification:*** ________

Interruptible Load: ________ ***kW***

Special Facilities: / Arrangements: ______________________________

Effective Date: ________

By: ______________________________

Transmission Customer ***Date***

By: ______________________________

Duke Energy Carolinas, LLC ***Date***

Attachment C
Distribution Rates

$$\begin{array}{l}\textit{Distribution Rates for} \\ \textit{TX Customer Delivery Points}\end{array} = \begin{pmatrix}\textit{Original Cost} \\ \textit{of Delivery Station}\end{pmatrix} \times \begin{pmatrix}\textit{\% Assigned To} \\ \textit{TX Customer}\end{pmatrix} \times (\textit{1.22\% per mo})$$

Original Cost of Delivery Station

For all assets in service as of September 30, 2000, the Original Cost of the Delivery Station shall be the values specified in this attachment. The Original Cost of all additional assets shall be the asset cost as assigned to FERC accounts 360 through 369 (or their successors). Retired assets will reduce the 'Original Cost of Delivery Station' by the values of the retired assets which were included in the 'Original Cost of Delivery Station'.

Percentage Assigned to Transmission Customer

This factor will apply to delivery stations only where the Transmission Customer is not the sole user. (For stations having the Transmission Customer as the sole user the value assigned to the factor will be one (1).)

For delivery stations in service on September 30, 2000, to which no new assets have been added, the factor is determined by the Percentage Use of Station Capability ("Percentage of Capability Method"). The Percentage Use of Station Capability formula is as follows:

The higher of

$$\begin{array}{l}\textit{Percentage Use Of} \\ \textit{Station Capability}\end{array} = \frac{\begin{array}{c}\textit{TX Customer} \\ \textit{Contract kVA}\end{array}}{\textit{Delivery Station kVA}}$$

where

$$\textit{TX Customer Contract kVA} = \frac{\textit{Contract } kW_1}{\%\textit{Power Factor}(\textit{Maximum Non}-\textit{coincident } 12\textit{ Mo. Peak}_2)}$$

or

$$\begin{array}{l}\textit{Percentage Use Of} \\ \textit{Station Capability}\end{array} = \frac{\begin{array}{c}\textit{TX Customer kW Peak} \\ 60\textit{ Minute Integrated Clock Hour Demand}\end{array}}{\textit{Delivery Station kW}}$$

where

$$Delivery\ Station\ \mathrm{k}W = (Delivery\ Station\ \mathrm{k}VA) \times$$
$$(\%Power\ Factor(Maximum\ Non-coincident\ 12\ Mo.Peak_1))$$

For new Delivery Stations placed in service after September 30, 2000, and for Delivery Stations where new assets have been added,[2] the factor is determined by Percentage of Station Use ("Percentage of Station Use Method") as follows:

$$Percentage\ of\ Station\ Use = \frac{\begin{array}{c}TX\ Customer\ Integrated\ 60\ Minute\\ kW\ Demand\ at\ Hour\ of\ Delivery\ Station\ Peak\end{array}}{\begin{array}{c}Delivery\ Station\ Integrated\ 60\ Minute\\ kW\ Demand\ at\ Hour\ of\ Delivery\ Station\ Peak\end{array}}$$

The hour of the Delivery Station Peak is the hour of maximum delivery station integrated 60 minute demand for the current month and previous 11 months. Temporary load shifts and other unusual circumstances will be excluded from the Delivery Station Peak calculation. If metering is not in place to determine the hour of the delivery station peak, the Percentage of Capability Method shall be used.

A Delivery Station may be terminated by either the Transmission Provider or the Transmission Customer upon reasonable notice. The initiator of the termination shall be responsible for paying any loss due to early retirement incurred by the other Party involving assets covered by these distribution rates.

These distribution rates do **NOT** include the costs for metering and metering equipment.

Transmission Provider will provide advance notice to Transmission Customer about changes to customer-specific facilities that will increase Transmission Customer's costs through a direct assignment charge.

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1 Contract kW is equivalent to the term *Planned Demand* located on the 'Delivery Point Data Sheet'.

2 The definition of a new asset will be limited to

a. the addition or replacement of transformers, capacitors, isolating devices and instrument transformers (non-meter application), or

b. a cumulative increase in the original cost of a delivery point to 125% of its initial value.

1. LOSS DUE TO EARLY RETIREMENT: Loss due to early retirement shall consist of replacement costs less accumulated depreciation, less salvage plus cost of removal, and in the case of Transmission Customer, when the loss due to early retirement is occasioned by Transmission Provider initiating the termination, reintegration costs shall be added.

2. REPLACEMENT COST: Replacement Cost shall be the cost of the identical item at the time of the sale, the time of replacement, or retirement, as the case may be, or where such identical item is no longer available, the closest comparable item shall be used to determine the cost.

3. DEPRECIATION: Depreciation shall be calculated at the annual rate of and in the manner of Transmission Provider's then current rate and method as set forth in Transmission Provider's FERC Form 1, page 430, entitled "Depreciation and Amortization of Electric Plant" and shall be applied to Replacement Cost. Accumulated Depreciation is the Annual Depreciation so calculated times the number of years from the date of installation to the date on which the calculation is made. Depreciation shall be limited to a maximum of 75% of Replacement Cost.

4. SALVAGE: Salvage shall consist of reusable and non-reusable items of equipment. Where an item of equipment is reusable, the value of such item shall be determined by Replacement Cost less Accumulated Depreciation. Where an item is non-reusable its value shall be equal to the proceeds received by Transmission Provider from its sale as scrap. The total of the value of reusable and nonreusable items shall be credited in calculating the loss due to early retirement.

5. COST OF REMOVAL: Cost of removal shall include direct labor plus a percentage for regular employee fringe benefits and a percentage for engineering and supervision, cost of use of equipment and miscellaneous expenses. The charges for cost of removal will be calculated consistent with regular charges made to others for similar work at that time.

6. REINTEGRATION COSTS: Reintegration costs shall include direct labor plus a reasonable percentage for regular employee fringe benefits and a reasonable percentage for engineering and supervision, cost of use of equipment, cost of materials, and miscellaneous expenses and are limited to those costs required to allow Transmission Customer to connect the new Delivery Point with its lines, by the most practical and direct route, which were previously connected with the terminated Delivery Point. The charges for the costs of reintegration will be calculated consistent with the standard methodology being used by the Participant at that time.

Delivery Locations	Original Cost ($)

Attachment D
Power Factor Penalty

1.0 Power Factor Compliance Requirements per Delivery Point

Beginning with the billing period which follows the later of: i) September 1, 2006, or ii) the month in which Duke complies with the requirements set forth in the Transmission Provider's Facility Connection Requirements ("FCR"), the Transmission Customer must meet the power factor requirements set forth in the FCR or pay penalties specified in Section 2.0 herein.

The Transmission Provider will provide power factor information for each Duke Electric Distribution substations to demonstrate compliance with the power factor standards set forth in Attachment F of the NITSA. If the Transmission Provider's Electric Distribution substations are not in compliance with the power factor standards set forth in Attachment F of the NITSA, the Transmission Customer will not be subject to these power factor penalties until such time as the Transmission Provider has demonstrated that the Transmission Provider's Electric Distribution substations are in compliance with the power factor standards.

Power Factor Groups are defined in Attachment F of the NITSA.

2.0 Penalty Formula

The penalties for failure to meet the power factor requirements are provided:

Power Factor Groups consisting of 1 Delivery Point:

Peak Period Penalty = {Delivery Point kVar Demand at Peak – (Delivery Point kW Demand at Peak X 0.2718)} X 0.75/kVar

Valley Period Penalty = Delivery Point Leading kVar Demand at Valley X $0.75/kVar

Power Factor Groups consisting of 2 or more Delivery Points:

Peak Period Penalty:

Scenario 1: The aggregate power factor of the group is less than 96.5% lagging at the hour of monthly transmission system peak. The following penalty will be assessed.

Peak Period Group Penalty = {Delivery Group kVar Demand at Peak – (Delivery Group kW Demand at Peak X 0.2718)} X 0.75/kVar

Scenario 2: The aggregate power factor of the group meets the power factor requirement at the hour of monthly transmission system peak but one or more delivery points in the group are operated at a power factor outside the 92 % lagging to 92 % leading range. Each delivery point with a power factor outside the desired power factor range will be assessed the following penalty.

Peak Period Penalty Per Delivery = {Delivery Point kVar Demand at Peak– (Delivery Point kW Demand at Peak X 0.2718)} X 0.75/kVar

Scenario 3: The aggregate power factor of the group is less than 96.5% lagging at the hour of monthly transmission system peak and one or more delivery points in the group are operated at a power factor outside the 92 % lagging to 92 % leading range. The following penalty for the group and for each delivery will be assessed.

Peak Period Group Penalty = {Delivery Group kVar Demand at Peak– (Delivery Group kW Demand at Peak X 0.2718)} X 0.75/kVar

Peak Period Penalty Per Delivery = {Delivery Point kVar Demand at Peak– (Delivery Point kW Demand at Peak X 0.2718)} X 0.75/kVar

Total Peak Period Penalty = Peak Period Group Penalty + $\sum_{i=1}^{n}$ Peak Period Penalty Per Delivery

Where n is the total number of delivery points in the group in violation of the power factor requirements.

Valley Period Penalty:

Scenario 1: The aggregate power factor of the group is leading at the hour of monthly transmission system valley. The following penalty will be assessed.

Valley Period Group Penalty = Delivery Group Leading kVar Demand at Valley X $0.75/kVar

Scenario 2: The aggregate power factor of the group meets the power factor requirement at the hour of monthly transmission system valley but one or more delivery points in the group are operated at a power factor outside the 92 % lagging to 92 % leading range. Each delivery point with a power factor outside the desired power factor range will be assessed the following penalty.

Valley Period Penalty Per Delivery = Delivery Point Leading kVar Demand at Valley X $0.75/kVar

Scenario 3: The aggregate power factor of the group is leading at the hour of monthly transmission system valley and one or more delivery points in the group are operated at a power factor outside the 92 % lagging to 92 % leading range. The following penalty for the group and for each delivery will be assessed.

Valley Period Group Penalty = Delivery Group Leading kVar Demand at Valley X \$0.75/kVar

Valley Period Penalty Per Delivery = Delivery Point Leading kVar Demand at Valley X \$0.75/kVar

Total Valley Period Penalty = Valley Period Group Penalty + $\sum_{i=1}^{n}$ Valley Period Penalty Per Delivery$_i$

Where n is the total number of delivery points in the group in violation of the power factor requirements.

3.0 Terms

Delivery Point kW Demand at Peak - The kW demand at the Delivery Point registered at the hour of the Transmission Provider's Monthly Transmission System Peak

Delivery Group kW Demand at Peak - The sum of kW demand registered at the hour of the Transmission Provider's Monthly Transmission System Peak at each Delivery Point in the Delivery Point Group

Delivery Point kVar Demand at Peak1- The kVar demand at the Delivery Point registered at the hour of the Transmission Provider's Monthly Transmission System Peak

Delivery Group kVar Demand at Peak[1] - The sum of kVar demand registered at the hour of the Transmission Provider's Monthly Transmission System Peak at each Delivery Point in the Delivery Point Group.

Delivery Point Leading kVar Demand at Valley[1] - The leading kVar demand at the Delivery Point registered at the hour of the Transmission Provider's Monthly Transmission System valley

Delivery Group Leading kVar Demand at Valley[1] - The sum of kVar demand registered at the hour of the Transmission Provider's Monthly Transmission System valley at each Delivery Point in the Delivery Point Group.

4.0 Duke Capacitors in Delivery Stations

The Delivery Point kVar Demand at Peak, Delivery Group kVar Demand at Peak, the Delivery Point Leading kVar Demand at Valley, and the Delivery Group Leading kVar Demand at Valley will account for the presence of capacitors (if any) owned by Duke at the distribution delivery station. To prevent penalizing the Transmission Customer for the Duke's operation of its capacitors, the Duke capacitors will be considered operational during the day and hour of the monthly transmission system peak regardless of the actual

1 As adjusted in accordance with Section 4.0.

operating status of the Duke capacitors. Likewise, the Duke capacitors will be considered not operational during the day and hour of the monthly transmission system valley regardless of the actual operating status of the Duke capacitors.

5.0 Temporary Waiver of Power Factor Requirements for New Delivery Points

The Transmission Customer may request a 24-month partial waiver of the Peak Period Power Factor requirements for new delivery points. This waiver would be to allow the transmission customer adequate time to develop a new distribution voltage profile for the new delivery point and to perform the associated feeder work. The form of the partial waiver would be as follows:

1. For the first 12-month period following the in-service date of the new delivery, the Peak Period Power Factor requirements for that delivery will be:

Peak Periods - The Transmission Customer must operate its electrical system in a manner resulting in a power factor not less than 90% lagging as measured at the delivery point at the hour of transmission system peak on a monthly basis for the months of June, July, August, and September. A lagging power factor of less than 90% lagging as measured at the delivery point at the hour of transmission system peak for the specified months will result in a penalty. The penalty will be calculated using the following formula:

Peak Period Penalty = {Delivery Point kVar Demand at Peak– (Delivery Point kW Demand at Peak X 0.4843)} X 0.75/kVar

2. For the second 12-month period following the in-service date of the new delivery, the Peak Period Power Factor requirements for that delivery will be:

Peak Periods - The Transmission Customer must operate its electrical system in a manner resulting in a power factor not less than 94% lagging as measured at the delivery point at the hour of transmission system peak on a monthly basis for the months of June, July, August, and September. A lagging power factor of less than 94% lagging as measured at the delivery point at the hour of transmission system peak for the specified months will result in a penalty. The penalty will be calculated using the following formula:

Peak Period Penalty = {Delivery Point kVar Demand at Peak– (Delivery Point kW Demand at Peak X 0.3629)} X 0.75/kVar

3. The new delivery point can not be included in a power factor group for the duration of a temporary waiver.

6.0 Waiver of Valley Power Factor Requirements for Delivery Points serving Underground Distribution Systems

The Transmission Customer may request a waiver from the Valley Period Power Factor requirement for any delivery point dedicated to serving an underground distribution system. Duke recognizes that such systems may be capacitive in nature at minimum loads and may present a leading power factor at the delivery point. In requesting this waiver, the

Transmission Customer must demonstrate that the delivery point is capacitive in nature at minimum loads and that no capacitors are in-service at such times. If the delivery point receives a waiver it cannot be included in a power factor group.

Attachment E
Network Operating Agreement

1.0 Control Area Requirements

The Transmission Customer shall: (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council ("NERC"), Southeastern Electric Reliability Council ("SERC"), and Virginia-Carolinas Reliability Group ("VACAR") or any of their successors; (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider; or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with other entities, consistent with Good Utility Practice, which satisfies NERC, SERC and VACAR requirements. The Transmission Customer shall plan, construct, operate and maintain its facilities and system in accordance with Good Utility Practice, which shall include, but not be limited to, all applicable guidelines of NERC, SERC and VACAR, as they may be modified from time to time, and any generally accepted practices in the region.

2.0 Network Operating Committee

(a) The Transmission Provider and the Transmission Customer shall each appoint a member and an alternate to a Network Operating Committee, and so notify the other Party of such appointment in writing. Such appointments may be changed at any time by similar notice. Each member and alternate shall be a responsible person working with the day to day operations of their respective systems. The Network Operating Committee shall meet as necessary to carry out the duties set forth herein. The Network Operating Committee shall also represent the Parties in all other operational matters not identified below that may be delegated to it by mutual agreement of the Parties. The Network Operating Committee shall hold meetings at the request of either Party, at a time and place agreed upon by the members of the Network Operating Committee.

(b) The Network Operating Committee shall coordinate operating criteria for the Parties' respective responsibilities under the Tariff, NITSA, and NOA including: (i) operate and maintain equipment necessary for integrating the Transmission Customer system within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment); (ii) transferring data, as necessary and as applicable, between the Transmission Provider and the Transmission Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33 of the Tariff, voltage schedules, loss factors, and other real time data); (iii) using software programs required for data links and constraint dispatching; (iv) exchanging data on forecasted loads and resources necessary for long-term planning; (v) addressing any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols; and (vi) developing and implementing communications protocols and procedures for the exchange of scheduling information. The Network Operating Committee shall have no power to amend or alter the provisions of this NOA or the NITSA. The Network Operating Committee shall use the standards set forth in the Transmission Provider's FCR document, as may be amended from time to time. The Network Operating Committee shall establish procedures: (i) to establish and verify initial and continuous compliance with the FCR, including the implementation of revised FCR provisions; and (ii) to correct failures to comply in a timely manner.

3.0 Network Operating Committee Agreements

(a) Each Party shall cooperate in providing to the Network Operating Committee all information required in the performance of the Network Operating Committee's duties. All decisions and agreements, if any, made by the Network Operating Committee shall be evidenced in writing and approved by each member of the Operating Committee, and shall be in accordance with the Tariff, the NITSA, and the NOA.

(b) Disputes within the Network Operating Committee shall be resolved in accordance with the Dispute Resolution Procedures in the Tariff.

4.0 Redispatch Procedures

(a) The Transmission Provider may implement redispatch procedures in accordance with Section 33.2 of the Tariff. If the Transmission Provider has redispatch procedures that have been accepted for filing and permitted to go into effect by the Federal Energy Regulatory Commission ("FERC" or the "Commission"), those procedures will be adhered to by the Transmission Provider and the Transmission Customer in any instance in which redispatch is implemented. Until such time as the FERC has permitted the Transmission Provider's redispatch procedures to go into effect, redispatch will require mutual consent by both the Transmission Provider and the Transmission Customer. The Transmission Customer shall respond immediately to requests for redispatch from the Transmission Provider's system operator.

(b) The Transmission Customer will submit to the Transmission Provider verifiable cost data for its Network Resources, which estimates the cost to the Transmission Customer of changing the generation output of each of its Network Resources. This cost data will be used, along with similar data for the Transmission Provider's resources, as the basis for least-cost redispatch. The Transmission Provider's operations personnel will keep this data confidential, and will disclose it only to those who require the information in order to carry out the redispatch function. Under no circumstances shall the Transmission Provider disclose this data to the Transmission Provider's Bulk Power Marketing function or any other marketer. If the Transmission Customer experiences changes to its costs, the Transmission Customer will submit those changes to the Transmission Provider's system operator.

(c) The Transmission Customer may audit, at its own expense, redispatch events (such as the cause or necessity of the redispatch) during normal business hours following reasonable notice to the Transmission Provider. Either the Transmission Customer or the Transmission Provider may request an audit of the other Party's cost data. Any audit of cost data will be performed by an independent agent at the requesting Party's cost. Such independent agent will be required to keep all cost data confidential.

(d) Once redispatch has been implemented, the Transmission Provider will book in a separate account the redispatch costs incurred by the Transmission Provider and the Transmission Customer based on the submitted cost data. The Transmission Provider and all Transmission Customers will each bear a proportional share of the total redispatch costs based on their then current Load Ratio Shares. The redispatch charge or credit, as appropriate, will be reflected on the Transmission Customer's monthly bill.

5.0 Metering

(a) The Transmission Customer will be responsible for the purchase, installation, operation, maintenance, repair, and replacement of all metering equipment, with the exception of metering associated with NCEMC's ownership share of the Catawba Nuclear Station, including communication equipment and paths, necessary to provide Network Integration Transmission Service, except as otherwise set forth in this NOA. All metering equipment of the Transmission Customer shall conform to Good Utility Practice and the standards and practices of the Transmission Provider's Control Area where necessary for implementation of Network Integration Transmission Service. Prior to its installation, the Transmission Provider and the Transmission Customer shall review the metering equipment to ensure conformance with such standards or practices as applicable. The Transmission Customer may, by mutual agreement of the Parties, lease or purchase metering equipment of the Transmission Provider for all or part of this obligation.

(b) Electric capacity and energy received by the Transmission Provider directly from the Transmission Customer's Network Resources will be measured by meters installed at the Transmission Customer's Network Resources. Electric capacity and energy which are wheeled for the Transmission Customer by a neighboring system will be received at designated Points of Receipt between such neighboring system and the Transmission Provider's Control Area. When measurement is made at any location other than a Point of Receipt, suitable adjustment for losses between the point of measurement and the Point of Receipt will be agreed upon in writing between the Parties hereto and will be applied to all measurements so made. Metered receipts used in billing and accounting hereunder will in all cases include adjustments for such losses.

(c) Electric capacity and energy delivered to the Transmission Customer's Network Loads by the Transmission Provider will be measured by meters installed at the Delivery Points to such Network Loads. Meters may be placed at locations other than Delivery Points by mutual agreement of the Parties. When measurement is made at any location other than a Delivery Point, suitable adjustment for losses between the point of measurement and the Delivery Point will be agreed upon in writing between the Parties hereto and will be applied to all measurements so made. Metered receipts used in billing and accounting hereunder will in all cases include adjustments for such losses. In addition, the Transmission Customer will provide written confirmation of its commitment not to tap an owned transmission line before a new metered delivery is put in service without sixty (60) days' advance notification to the Transmission Provider. Further, the Transmission

Customer will allow the Transmission Provider access to its facilities for inspection of the transmission line upon the Transmission Provider's reasonable notice.

(d) Meters at the Transmission Customer's Network Resources, where applicable, and Network Loads will be tested at least biennially. Representatives of the non-owning Party will be provided notification of and afforded an opportunity to witness such tests.

(e) The owning Party will, upon request of the non-owning Party, test any meter at the Network Resources or Network Load used for determining the receipt or delivery of electric capacity and energy by the Transmission Provider. In the event the test shows the meter to be inaccurate, the owning Party will make any necessary adjustments, repairs, or replacements. In the event the test shows the meter to be accurate, all costs of the test will be paid by the non-owning Party.

(f) In the event any meter used to measure capacity and energy fails to register or is found to be inaccurate, appropriate billing adjustments, based on the best information available, will be agreed upon by the Parties hereto. Meters shall be calibrated to 0.5% accuracy at unity power factor for both full load and light load. These meters shall be calibrated to 1.0% accuracy for 0.5 power factor at full load. Metering accuracy limits are stated in the following table.

METER ACCURACY LIMITS			
Watt-hour Function			**Var-hour Function**
Full Load	Power Factor	Light Load	Power Factor
+/- 0.5	+/- 1.0	+/- 0.5	+/- 1.0

Notes:

- Watt-hour and var-hour functions should be tested in both directions of energy flow (In and Out).
- When compensating for transformer or line loss, utilize stated limits above or 5% of desired compensation, whichever is greater.
- The meter shall be tested with compensation applied to obtain a true test of the installation.

Test Points	***Volts***	***Amps***	***Power Factor***
Full Load	120	5	1.0
Power Factor	120	5	0.5
Light Load	120	0.5	1.0

These values will be considered to be correct and accurate insofar as correction of billing is concerned. If, as a result of any test, a meter is found to be out of compliance with these values, then the record of readings of such meter previously taken will be corrected according to the percentage of any inaccuracy so found, but no correction will extend beyond ninety (90) days prior to the day on which inaccuracy is discovered by such test.

(g) The Transmission Provider will have the right to install, at its own expense, suitable metering equipment at any Point(s) of Receipt or Delivery, as herein provided for the purpose of checking any meters installed by the Transmission Customer.

(h) The Transmission Customer will provide the metering as described in Section 7.0(a). The Transmission Customer and the Transmission Provider (collectively "Metering Parties") will have electronic access to the meters for the purpose of collecting and processing meter data for billing as defined in the Catawba Interconnection Agreement, FERC Electric Rate Schedule No. 273 ("IA") and the Tariff. The Metering Parties will also have electronic access to the meters for the purpose of verifying the accuracy of the metered data and meter configuration. If physical access to metering equipment located on premises owned or controlled by a Metering Party is needed, the owning Metering Party will furnish the non-owning Metering Party's representative with physical access to the meters upon reasonable prior request for the purpose of: (i) collecting and processing meter data for billing under the IA and Tariff; and /or (ii) verifying the accuracy of the metered data and meter configuration. The owning Metering Party shall have the right to have an observer present during such activities by the non-owning Metering Party's representatives.

(i) The Metering Party that owns a meter will provide any equipment nameplate and configuration information requested by the non-owning Metering Party to allow the non-owning Metering Party to verify that the meter measurement and loss compensation calculation, if applicable, is accurate. The owning Metering Party shall notify the non-owning Metering Party at least thirty (30) days in advance of any changes to the metering, meter programming, or meter equipment. In the event that changes are made in response to equipment failure, notification will be made within two (2) business days after the failure is discovered.

6.0 Control Area and Data Equipment

(a) The Transmission Customer will be responsible for the purchase, installation, operation, maintenance, repair, and replacement of all data acquisition equipment, metering equipment, protection equipment, and any other associated equipment and software, which may be required for the Transmission Customer to operate in accordance with Section 3.0 of this NOA. Such equipment shall conform to Good Utility Practice and conform to the reasonable standards and practices of the Transmission Provider's Control Area. Prior to its installation, the Transmission Provider and the Transmission Customer shall review the equipment and software required by this Section to ensure conformance with such standards or practices.

(b) The real time telemetry and data to be received by the Transmission Provider's system operator and the Transmission Customer shall be determined initially by the Parties. Subsequent changes shall be determined by the Network Operating Committee. Such telemetry and data shall be necessary for monitoring of system operations for reliability, security, or economics. This telemetry includes, but is not limited to, loads, line flows, voltages, generator output, and breaker status at any of the Transmission Customer's transmission facilities. To the extent telemetry is required that is not available, the

Transmission Customer shall, at its own expense, install any metering equipment, data acquisition equipment, or other equipment and software necessary for the telemetry to be received by the Transmission Provider's system operator.

(c) Each Party shall be responsible for implementing any computer modifications or changes required to its own computer system(s) as necessary to implement this Section.

7.0 Operating Requirements

(a) The Transmission Customer shall operate its generating resources in a manner consistent with that of the Transmission Provider, following voltage schedules, utilizing free governor response, meeting power factor requirements at the point of interconnection with the Transmission Provider's system, and other such criteria required by NERC, SERC, or VACAR, or any of their successors, and consistently adhered to by the Transmission Provider.

(b) Insofar as practicable, the Transmission Provider and the Transmission Customer shall protect, operate, and maintain their respective systems so as to avoid or minimize the likelihood of disturbances which might cause impairment of service on the system(s) of the other. The Parties, consistent with Good Utility Practice, shall implement load shedding programs to maintain the reliability and integrity of the Transmission System, as provided in Section 33.6 of the Tariff. Load shedding shall include: (i) automatic load shedding by underfrequency device; and (ii) manual load shedding. The Transmission Provider will implement load shedding to maintain the relative sizes of load served, unless otherwise required by circumstances beyond the control of the Transmission Provider or the Transmission Customer. Automatic load shedding devices will operate without notice. When manual load shedding is relied upon, the Transmission Provider shall notify the Transmission Customer's dispatchers or schedulers of the required action and the Transmission Customer shall take immediate steps to comply.

(c) The Transmission Customer shall, at its own expense, provide, operate, and maintain in service high-speed, underfrequency load shedding equipment. The Transmission Customer will install underfrequency devices consistent with NERC, SERC, and VACAR, or any of their successors requirements, to disconnect automatically approximately thirty percent (30%) of its Network Load in a manner consistent with that followed by the Transmission Provider, which is three (3) steps of approximately ten percent (10%) each at frequency set points of 59.3 Hertz, 59.0 Hertz and 58.5 Hertz. The installation of underfrequency relays to accomplish any additional load shedding above that already installed shall be completed on a schedule agreed to by the Network Operating Committee. The Network Operating Committee may review the amount of load that would be disconnected automatically and make such adjustments and changes as necessary.

(d) In the event the Transmission Provider reasonably modifies the load shedding system in accordance with Good Utility Practice, the Transmission Customer shall, at its expense, make changes to its equipment and setting of such equipment, as required. The Transmission Customer shall test and inspect the load shedding equipment within ninety (90) days of taking Network Integration Transmission Service under the Tariff and thereafter in accordance with Good Utility Practice, but no more often than the Transmission Provider, and provide a written report to the Transmission Provider. The Transmission Provider may request a test of the load shedding equipment with reasonable written notice at the expense of the Transmission Provider. If the Transmission Customer installs automatic load shedding equipment, the Transmission Provider shall provide to the Transmission Customer a written report upon each test of the Transmission Provider's automatic load shedding equipment. The Parties will provide each other with copies of NERC compliance reports, as they relate to the NERC Planning Standards on underfrequency load shedding.

8.0 Operational Information

(a) The Transmission Customer shall provide by September 1 of each year the Transmission Customer's Network Resource Availability Forecast (e.g., all planned resource outages, including off-line and on-line dates) for the following year. Such forecast shall be made in accordance with Good Utility Practice. The Transmission Customer shall inform the Transmission Provider, in a timely manner, of any changes to the Transmission Customer's Network Resource Availability Forecast. In the event that the Transmission Provider determines, in compliance with its rights and responsibilities under Section 28.2 of the Tariff, that such forecast cannot be accommodated due to a transmission constraint on its Transmission System, then the Transmission Provider shall notify the Network Operating Committee which shall meet to resolve the matter. If the Network Operating Committee is unable to resolve the matter in a timely fashion, then the Dispute Resolution Procedures set forth in Section 12 of the Tariff shall apply.

(b) The Transmission Customer shall provide, at least thirty-six (36) hours in advance of every calendar day, the Transmission Customer's best forecast of any planned transmission or Network Resource outage(s) and other operating information reasonably required by the Transmission Provider to provide Transmission Service under the NITSA and this NOA. In the event that such planned outages cannot be accommodated due to a transmission constraint on the Transmission Provider's Transmission System and the Network Operating Committee cannot agree on remedial measures, the provisions of Section 33 of the Tariff will be implemented.

(c) The Transmission Provider and the Transmission Customer shall notify and coordinate with the other Party prior to the commencement of any work by either Party (or contractors or agents performing on their behalf) which may directly or indirectly have an adverse effect on the other Party. All information provided by either Party to the other under this Section shall be treated as confidential.

9.0 Network Planning

In order for the Transmission Provider to plan, on an ongoing basis, to meet the Transmission Customer's requirements for Network Integration Transmission Service, the Transmission Customer shall provide to the Transmission Provider, by September 1 of each year, updated information (current year and 10-year projection) for Network Loads and Network Resources, as well as any other information reasonably necessary to plan for

Network Integration Transmission Service. This type of information is consistent with the Transmission Provider's information requirements for planning to serve its Native Load Customers. The data will be provided in a format consistent with that used by the Transmission Provider.

10.0 Character of Service

Power and energy delivered under the NITSA and this NOA shall be delivered as three-phase alternating current at a frequency of approximately sixty (60) Hertz, and at the nominal voltages at the Points of Delivery and Points of Receipt.

11.0 Transfer of Power and Energy Through Other Systems

Since the Transmission Provider's Transmission System is, and will be, directly and indirectly connected with other electric systems, it is recognized that, because of the physical and electrical characteristics of the facilities involved, electric capacity and energy delivered under the NITSA and this NOA will flow through such other systems. The Parties agree to advise other electric systems as deemed appropriate of such scheduled transfers and to attempt to maintain good relationships with affected third parties. The Parties further agree that the Transmission Customer will be responsible for making arrangements, suitable to the Transmission Provider, with neighboring transmission providers as necessary for the scheduling and delivery of electric capacity and energy from any other designated or non-designated Network Resources of the Transmission Customer to the Transmission Provider's Control Area.

Attachment F
Other Charges

1.0 Direct Assignment Charges (recurring):

ATTACHMENT G

~~Network Operating Agreement~~

NETWORK OPERATING AGREEMENT

(CP&L ZONE AND FPC ZONE)

The Transmission Provider and ___________________________ (Transmission Customer) agree that the provisions of this Network Operating Agreement ("NOA") and the Service Agreement govern the Transmission Provider's provision of Network Integration Service/Network Contract Demand Transmission Service to the Transmission Customer in accordance with the Transmission Provider's Open-Access Transmission Tariff (Tariff), as it may be amended from time to time. Unless specified herein, capitalized terms shall refer to terms defined in the Tariff.[1]

1.0 Control Area Requirements

The Transmission Customer shall: (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council ("NERC") and either the Southeastern Electric Reliability Council ("SERC") or the Florida Regional Reliability Council ("FRCC"), as applicable; or (ii) satisfy its Control Area requirements, including all Ancillary Services, by contracting with the Transmission Provider; or (iii) satisfy its Control Area requirements, including all Ancillary Services, by contracting with another entity that can satisfy those requirements in a manner that is consistent with the Tariff and Good Utility Practice and satisfies NERC and SERC or FRCC standards. The Transmission Customer shall plan, construct, operate and maintain its facilities and system

1 This Attachment G applies only to the CP&L Zone and the FPC Zone. The NOA applicable to the DEC Zone is available at Attachment F-2, as Attachment E to the Service Agreement for Network Integration Transmission Service.

Other than the page following, the remaining pages to Attachment G contain no changes of substance and are not included.

Provider will implement least-cost redispatch consistent with its existing contractual obligations and its current practices and procedures for its own resources per Sections 33.2 and 42.2 of the Tariff. The Transmission Customer shall respond within ten minutes to requests for redispatch from the Transmission Provider's Energy Control Center.

(c) The Transmission Customer may audit, at its own expense, particular redispatch events (such as the cause or necessity of the redispatch) during normal business hours following reasonable notice to the Transmission Provider. Either the Transmission Customer or the Transmission Provider may request an audit of the other Party's cost data. Any audit of cost data will be performed by an independent agent at the requesting Party's cost. Such independent agent will be a nationally recognized accounting firm and will be required to keep all cost data confidential.

(d) Once redispatch has been implemented, the Transmission Provider will book in a separate account the redispatch costs incurred by the Transmission Provider and the Transmission Customer based on the submitted cost data. The Transmission Provider and the Transmission Customer will each bear a proportional share of the total redispatch costs pursuant to Sections 33 and 42 ~~and Attachment J~~ of the Tariff. The redispatch charge or credit, as appropriate, will be reflected on the Transmission Customer's monthly bill.

3.0 Metering

(a) Unless otherwise agreed and except as provided in Section 3(b), the Transmission Provider will be responsible for the installation, operation, maintenance, repair and replacement of all metering equipment necessary to provide Network Integration

ATTACHMENT H

NETWORK INTEGRATION TRANSMISSION SERVICE

~~Network Integration Transmission Service~~

~~[CP&L Zone Only]~~

I. FPC Zone

The Annual Transmission Revenue Requirement for purposes of Network Integration Transmission Service shall be as determined by Schedule 10-A.2.

II. DEC Zone

The Annual Transmission Revenue Requirement for purposes of Network Integration Transmission Service shall be as determined by Schedule 10-B, Exhibit B.

III. CP&L Zone

The Transmission Customers shall compensate the Transmission Provider each month for Network Load for the applicable month as follows:

1. **Monthly Delivery:** The charge for network integration service is derived from the Formula Rate, which is set forth in OATT Attachment H.1. The resulting rate is posted on the Transmission Provider's OASIS. The Formula Rate is implemented in accordance with the OATT Attachment H.2 Formula Rate Implementation Protocols. The charge for Network Integration Transmission Service shall be updated annually on June 1st of each year in accordance with the OATT Attachment H.2 Formula Rate Implementation Protocols.

NOTE: All quantities used in calculating the Network Integration Transmission Customer's Network Load shall be adjusted to the transmission system input level, i.e., shall include the transmission capacity amount associated with any applicable losses. As a result, the Customer's load, as metered at the Point(s) of Delivery (transmission exit level), will be increased using the Real Power Loss factor of 2.15% to bring the Customer's load to the generation level.

2. The Network Customer will designate and operate all Network Resources in accordance with the sub-parts of Section 30 of this Tariff. If the Network Customer desires to serve a portion of its load from an undesignated resource, it will be considered Secondary Service in accordance with Section 28.4.

3. The Transmission Customer will compensate the Transmission Provider for any redispatch costs in accordance with Section 34.4. ~~Redispatch costs will be computed in accordance with the methodology outlined in Attachment J.~~

The remaining page to Attachment H and Attachments H.1 and H.2 contain no changes of substance and are not included.

OATT ATTACHMENT H.3

FORMULA RATE NOTES

1.0 Non-load and Transmission-related Revenue Credits.

(i) The non-load and transmission-related revenue credits in the Formula Rate shall be determined in the following manner:

(1) All revenues associated with facilities allocated to the transmission function, including both direct and indirect allocations (e.g., general and intangible plant and administrative and general expense) shall be treated as revenue credits in the Formula Rate. Such revenue credits shall include, but shall not be limited to, transmission facilities lease/rental payments, direct assignment facilities charges, pole attachment fees, and general plant-related income.

(2) Transmission revenues from Short-Term Firm and Non-Firm Transmission Services under the OATT and transmission service similar to Short-Term Firm or Non-Firm Transmission Services under the OATT shall be treated as revenue credits in the Formula Rate.

(3) Transmission services revenues from FERC Account 456.1 shall be treated as revenue credits in the Formula Rate, but ancillary services revenues from FERC Account 456.1 shall not be revenue credits in the Formula Rate.

(4) All transmission revenue credits shall be directly assigned to the transmission function in the Formula Rate (i.e., they shall not be allocated in the Formula Rate using a transmission plant allocator).

(5) Revenues associated with indirect allocations of costs to the transmission function (e.g., general and intangible plant) shall be allocated to the transmission function in the

Formula Rate based on the same underlying indirect allocations of costs and treated as a revenue credit.

1.1 End-of-Year Data. The Formula Rate shall include the end-of-year balances from PEC's FERC Form No. 1 reports for the rate base items (other than Cash Working Capital) included in the Formula Rate.

1.2 Cash Working Capital. The Formula Rate shall include cash working capital based on a formulary approach as follows: 1/8 multiplied by the total of operation and maintenance expense, as specified in the Formula Rate template attached to this Settlement Agreement as Exhibit A.

1.3 Prepayments for Network Upgrades by Generators. The Formula Rate shall include as an offset to rate base in the Formula Rate the amount of refundable prepayments made by generators for network upgrades that PEC has not refunded to the OATT transmission customer as credits to its transmission charges; this will ensure PEC does not earn a return on those funds. Correspondingly, the amount of interest paid to OATT transmission customers as their balances are credited against their transmission service shall be included as an expense in the Formula Rate. PEC shall not capitalize and add any AFUDC to the completed cost of such network upgrades, but instead will include only the balance of any unrefunded interest accrued at the FERC refund interest rate as an addition to rate base. The Formula Rate includes a hypothetical example to illustrate how refundable prepayments for network upgrades are treated in the Formula Rate.

1.4 Credits for Customer-owned Facilities. The Formula Rate shall include a placeholder for any future credits for customer-owned facilities to prevent any under-recovery of revenues by PEC due to any credits provided to OATT transmission customers for their own facilities

1.5 Transmission Provider's Compliance with Order No. 2003. In accordance with FERC Order No. 2003, the Formula Rate shall exclude any transmission plant that meets the definition of "Interconnection Facilities" and was placed in service for PEC's own generation facilities after March 15, 2000.

1.6 Directly Assigned or Assignable Costs. The Formula Rate shall exclude all costs that are properly directly assigned or assignable to one or more particular customers, including costs directly assigned or assignable to PEC.

1.7 PEC Payments to "Affected Transmission Owners" and Regional Cost Allocation. On December 7, 2007, pursuant to Order No. 890, Progress Energy, Inc., on behalf of PEC, submitted its Order No. 890 Attachment K (included in this Tariff as Attachment N-1) compliance filing in Docket No. OA08-51-000. The regional cost allocation methodology addressed in this compliance filing is incorporated in the Formula Rate. Should FERC reject the filed methodology, then, within thirty days of refiling a revised cost allocation methodology with FERC, PEC shall submit to the Customers a proposal to address the treatment under the Formula Rate of any payments made by PEC to Affected Transmission Owners, and payments received by PEC as an Affected Transmission Owner, under such revised filing. If the interested Customers and PEC reach agreement within ninety days, PEC shall make a filing, pursuant to FPA Section 205, to change the Formula Rate to properly account for such payments. If the interested Customers and PEC do not reach agreement within ninety days, PEC may make a filing, pursuant to FPA Section 205, to change the Formula Rate to properly account for such payments, and any such filing may be opposed by any Customer.

1.8 Accumulated Deferred Income Taxes (ADIT). Accumulated deferred income taxes (ADIT) reflected in the Formula Rate shall be only such amounts as are properly allocated or assigned to the transmission function. In each Annual Update (as defined in the Formula Rate Implementation Protocols), PEC shall provide a spreadsheet that shows the functionalization of the FERC Form No. 1 reported amounts for ADIT and supports the amount of ADIT to be reflected in the Formula Rate. For example, the following ADIT items shall not be included in the Formula Rate because they are not transmission-related ADIT:

(i) Any future income tax deficiency items in ADIT shall be assigned to "other" in the Formula Rate.

(ii) Deferred taxes related to existing Environmental Cleanup Reserve shall be assigned to "other" in the Formula Rate.

(iii) Any future prepaid Pension related items shall be excluded from rate base in the Formula Rate and, accordingly, there shall be no ADIT balance offset for these items.

(iv) Because the unamortized balance of GridSouth costs is excluded from rate base pursuant to provision 3.5(ii), there will be no ADIT offset in the formula rate calculation.

1.9 Intangible Plant.

(i) In future Annual Updates, PEC shall provide supporting information concerning gross intangible plant investment and associated depreciation in order to establish net intangible plant investments so that OATT transmission customers may compare PEC's net intangible plant investments from year to year.

(ii) To the extent that the net intangible plant investment increases from one year to the next, PEC shall provide in the Annual Update sufficient information to explain the increase and to support the allocation of any portion of the increase to the transmission function. PEC shall adjust the allocation of net intangible plant investment in the Formula Rate to the extent necessary to reflect an appropriate allocation to the transmission function. PEC shall include this adjustment and supporting information in the Annual Informational Filing submitted to FERC. If there is a disagreement between PEC and a transmission customer concerning this matter, the disagreement shall be resolved through a Preliminary Challenge and/or Formal Challenge under the Formula Rate Implementation Protocols (rather than through an FPA Section 206 complaint).

1.10 Prepaid Pension Expense and Other Prepayments.

(i) The Formula Rate shall exclude prepaid pension expenses from rate base. The Formula Rate shall include any prepaid pension expenses as an expense to the extent set forth in Section 3.18(ii).

(ii) To the extent that prepaid pension expenses increase from one year to the next, PEC shall provide in the Annual Update sufficient information to explain the increase and to support the allocation of any portion of the increase to the transmission function. PEC shall adjust the allocation of prepaid expenses, to the extent necessary, to reflect an appropriate allocation to transmission. PEC shall include this adjustment and the supporting information in the Annual Informational Filing submitted to FERC. If there is a disagreement between PEC and a transmission customer concerning this matter, such disagreement shall be resolved through a Preliminary Challenge and/or Formal Challenge under the Formula Rate Implementation Protocols (rather than through an FPA Section 206 complaint).

1.11 Extraordinary Property Loss. If a property loss meets the requirements for treatment as an Extraordinary Property Loss (FERC Account 182.1), PEC may request FERC's permission to record the loss in that manner in its books of account. Separately, PEC may seek FERC's permission to recover through rates such prudently incurred costs as are associated with an Extraordinary Property Loss; provided, however, (i) pursuant to Section 3.7(ii) above, PEC may not include the amortization of any such Extraordinary Property Loss in the Formula Rate without having made a Section 205 filing to change the Formula Rate value for that item, and (ii) PEC may seek to reflect in the Formula Rate only that portion of such an Extraordinary Property Loss as may be properly allocated or assigned to the transmission function.

1.12 Extraordinary Transmission O&M Expenses. O&M expenses allocated or assigned to the transmission function that are extraordinary and non-recurring and have a material effect on charges shall be amortized in the Formula Rate over three to five years (subject to FERC approval), as appropriate under the circumstances. The Formula Rate shall include the unamortized balance in rate base.

1.13 Property Taxes. Property taxes shall be allocated in the Formula Rate using the Gross Plant allocator.

1.14 Property Insurance. Property insurance shall be allocated in the Formula Rate using the Gross Plant allocator.

1.15 PEC Power Marketing Costs.

(i) To the extent that any costs associated with PEC's power marketing operations may be included in Administrative and General ("A&G") expense accounts, those costs shall be excluded from the A&G expenses reflected in the Formula Rate.

(ii) The divisor of the labor allocator in the Formula Rate shall include any labor-related costs associated with PEC's power marketing operations.

1.16 FERC Account 561. Consistent with FERC Order No. 668, the Formula Rate reflects the appropriate treatment of Account 561 subaccounts such that the Formula Rate includes only those items associated with transmission service and excludes all other costs (for example, costs chargeable to Schedule 1 – Load Control and Dispatch Service).

1.17 Asset Retirement Obligations. The Formula Rate shall not include asset retirement obligations in any plant investment.

1.18 A&G Expenses. The Administrative and General expenses reflected in the Formula Rate shall not include any portion of PEC's expenses for advertising, charitable contributions, or other voluntary payments for such items as industry association dues (e.g., Edison Electric Institute dues) or contributions to industry research and development activities (e.g., Electric Power Research Institute).

ATTACHMENT I

~~**Index Of Network Integration Transmission Service**~~

~~**Customers**~~

INDEX OF NETWORK INTEGRATION TRANSMISSION SERVICE CUSTOMERS

See Transmission Provider's Electric Quarterly Report at the following Internet address:

~~<~~http://www.ferc.gov/docs-filing/eqr/data/spreadsheet.asp~~>~~

~~ATTACHMENT J~~

~~Redispatch Costs and Methodology~~

~~This Attachment J has been terminated and superseded by Order No. 890.~~

~~**Attachment P**~~

~~**Standard Large Generator Interconnection Procedures (LGIP)**~~

~~**(Applicable to Generating Facilities that exceed 20 MW)**~~

ATTACHMENT J

STANDARD LARGE GENERATOR INTERCONNECTION PROCEDURES (LGIP)

including

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT (LGIA)

The remaining pages to Attachment J
contain no changes of substance and are not included.

ATTACHMENT K

~~Transmission Planning Process~~
[FPC Previous Attachment K is Attachment N-2 in the Joint OATT]

THE INDEPENDENT ENTITY

[DEC ZONE]

1 OVERVIEW

1.1 This Attachment sets forth the authority and responsibility of the Independent Entity ("IE") in its role as such in the DEC Zone, as well as the responsibilities of the Transmission Provider, Generator Owners, Load Serving Entities, and other market participants relating to the functions to be performed by the Independent Entity.

1.2 The Transmission Provider will retain operational control over the Transmission System, but will be obligated to follow the directives of the Independent Entity as set forth herein. The specific division of responsibilities and functions between the Independent Entity and the Transmission Provider are set forth in this Attachment K.

1.3 Nothing in this Attachment K precludes the Independent Entity from providing the same or similar functions to other entities under a separate contract or expanding to a larger regional entity, provided that the Transmission Provider is reimbursed in an equitable manner for its capital investment as well as ongoing operations and maintenance costs in connection with any such new contract or expansion.

1.4 The Transmission Provider will provide the Commission with timely written notice that the Independent Entity has commenced operations as the Independent Entity upon such commencement. No later than forty-five days prior to the five-year anniversary of such commencement, the Independent Entity and the Transmission Provider shall jointly convene a stakeholder conference to ascertain the views of any Transmission Customer, Load-Serving Entity, Generator, or any other entities doing business in the Transmission Provider's service area (collectively "Tariff Participants") on whether there is a continuing need for an Independent Entity, including the stakeholders' views of the benefits provided by the Independent Entity and the costs of maintaining the Independent Entity. At this stakeholder conference, the Independent Entity will also summarize stakeholder comments it has received in the prior three years, to the extent such comments relate to the need for, or lack of need for, an Independent Entity. The Transmission Provider may file, at its sole discretion and pursuant to Section 205 of the Federal Power Act, to modify, amend, terminate, or otherwise alter this Attachment K. Nothing in this Attachment K shall alter or limit any rights the Transmission Provider may otherwise enjoy under the Tariff, Commission regulation, or the Federal Power Act.

2 DEFINITIONS

The following definitions shall apply to this Attachment. Capitalized terms that are not specifically defined herein shall have the meaning assigned to them under the Tariff or Large Generator Interconnection Procedures ("LGIP"), as applicable.

2.1 [Reserved].

2.2 ATC Methodology shall mean the criteria, standards, and procedures used to calculate Available Transfer Capability ("ATC") values as set forth in the following: (i) Tariff provisions applicable to ATC calculations, including Attachment C-3 to the Tariff; (ii) applicable North American Electric Reliability Council ("NERC") Reliability Standards and Southeastern Electric Reliability Council ("SERC") supplements to those standards; (iii) the Transmission Provider's ATC Procedures that are provided to the Independent Entity for posting on OASIS pursuant to Section 6.1.10 herein; and (iv) the Transmission Provider's local reliability criteria provided to the Independent Entity for posting on OASIS pursuant to Section 6.1.10 herein.

2.3 Base Case Model shall mean current power flow models representing the Transmission System used for reliability assessments, transmission service request studies, and economic studies. When referenced herein, "Base Case Model" refers to the annual, seasonal, monthly, or other power flow models used by the Independent Entity to evaluate TSRs or Interconnection Requests, as applicable to TSRs or Interconnection Requests.

2.4 Facilities Study Criteria shall mean the criteria, standards, and procedures used to perform Facilities Studies as set forth in the following: (i) Tariff provisions applicable to the performance of Facilities Studies; (ii) applicable NERC Reliability Standards and SERC supplements to those standards; (iii) the Transmission Provider's business practices related to Facilities Studies that are provided to the Independent Entity for posting on OASIS pursuant to Section 6.1.10 herein; and (iv) the Transmission Provider's local reliability criteria that are provided to the Independent Entity for posting on OASIS pursuant to Section 6.1.10 herein.

2.5 Interconnection SIS shall mean the Interconnection System Impact Study required under the LGIP.

2.6 Interconnection Studies shall mean studies required to interconnect new generation to the Transmission System under Order No. 2003.

2.7 Interconnection Study Criteria shall mean the criteria, standards, and procedures used to perform Interconnection Studies as set forth in the following: (i) the LGIP and LGIA provisions applicable to the performance of Interconnection Studies; (ii) applicable NERC Reliability Standards and SERC supplements to those standards; (iii) the Transmission Provider's business practices related to Interconnection Studies that are provided to the Independent Entity for posting on OASIS pursuant to Section 7.1.8 herein; and (iv) the Transmission Provider's local reliability criteria that are provided to the Independent Entity for posting on OASIS pursuant to Section 6.1.10 herein.

2.8 LGIA shall mean the Standard Large Generator Interconnection Agreement under Attachment J to the Tariff or the version of that agreement executed by an Interconnection Customer, as applicable.

2.9 LGIP shall mean the Standard Large Generator Interconnection Procedures under Attachment J to the Tariff.

2.10 Long-Term TSRs shall mean TSRs that are for a term of one year or greater in duration.

2.11 [Reserved].

2.12 Short-Term TSRs shall the mean TSRs that are for a term less than one-year in duration.

2.13 SIS shall mean the System Impact Study required under the Tariff to evaluate TSRs and to determine what magnitude of system upgrades, if any, might be required to grant a request.

2.14 SIS Criteria shall mean the criteria, standards and procedures used to perform System Impact Studies as set forth in the following: (i) Tariff provisions applicable to the performance of SISs, including Attachment D to the Tariff; (ii) applicable NERC Reliability Standards and SERC supplements to those standards; (iii) the Transmission Provider's business practices related to SISs that are provided to the Independent Entity for posting on OASIS pursuant to Section 6.1.10 herein; and (iv) the Transmission Provider's local reliability criteria that are provided to the Independent Entity for posting on OASIS pursuant to Section 6.1.10 herein.

2.15 [Reserved].

2.16 Transmission Study Criteria shall mean the ATC Methodology, the SIS Criteria, and the Facilities Study Criteria as defined herein.

2.17 Transmission Service Request or TSR shall mean a request submitted by an eligible Transmission Customer under the Tariff for either Point-to-Point Transmission Service or Network Integration Transmission Service, including a new designation of Network Resources or Network Load.

2.18 TSR Processing Criteria shall mean the criteria, standards, and procedures used to process TSRs as set forth in the following: (i) Tariff provisions applicable to TSR processing; (ii) FERC's OASIS Standards and Communication Protocols and Business Practice Standards for OASIS Transactions; and (iii) the Transmission Provider's business practices related to OASIS and TSR processing that are provided to the Independent Entity for posting on OASIS pursuant to Section 6.1.12 herein.

3 INDEPENDENCE

3.1 The Transmission Provider will retain the Independent Entity under an agreement that will be submitted to FERC for a determination that the agreement provides for the Independent Entity to be independent of the Transmission Provider, or any Tariff Participant.

3.2 If the Transmission Provider terminates its agreement with the Independent Entity in accordance with the provisions of such agreement, the Transmission Provider will retain a replacement Independent Entity to perform the functions provided for under this Attachment K, and the agreement with such replacement Independent Entity likewise will be submitted to FERC. Provided, however, that notwithstanding anything in this Attachment K to the contrary, the Transmission Provider shall have the right to withdraw this Attachment K if the Commission directs the Independent Entity to take any action, or Congress enacts legislation imposing any requirement, with regard to the Transmission Provider's Transmission System or mandating or permitting the Independent Entity to assume responsibility for any functions or services currently performed or provided by the Transmission Provider that would materially or adversely diminish, interfere with, or otherwise impinge or intrude upon the state regulatory commissions' jurisdiction over the Transmission Provider under applicable state laws and regulations.

3.3 The Independent Entity and its employees shall not be affiliated with and shall remain independent of the Transmission Provider or any Tariff Participant. All functions and responsibilities of the Independent Entity shall be performed by employees or agents of the Independent Entity. No such employees or agents shall be employed by the Transmission Provider or any affiliate (as defined in 18 C.F.R. § 35.34(b)(3) of FERC's regulations) of the Transmission Provider. The Independent Entity and its employees and agents shall be Independent of the Transmission Provider and of any Market Participant (as defined in 18 C.F.R. § 35.34(a)(2) of FERC's regulations) and all Affiliates of the Transmission Provider and any such Market Participant. For purposes of this Attachment K, "Independent" shall mean that the Independent Entity and its employees and agents are not subject to the control of the Transmission Provider or any Market Participant, and have full decisionmaking authority to perform all functions and responsibilities assigned to the Independent Entity under this Attachment K.

3.4 The Independent Entity shall perform the functions enumerated herein in an independent manner and, in all cases, shall use its independent judgment in ensuring that Transmission Service is provided on a nondiscriminatory basis. The Independent Entity and the Transmission Provider shall perform their respective functions in a manner consistent with Good Utility Practice, the Transmission Provider's obligations to Native Load Customers, and their obligations to Transmission Customers under FERC Orders No. 888, 889, and 2003. The Independent Entity and its employees shall not discriminate against the Transmission Provider or any Tariff Participant, and shall implement the provisions of this Attachment K in a fair and non-discriminatory manner.

3.4.1 All employees of the Independent Entity performing functions under this Attachment shall be treated, for the purposes of FERC's Standards of Conduct set forth 18 C.F.R. Part 358, as the equivalent of transmission/reliability employees of the Transmission Provider, and all restrictions related to information sharing and other relationships between merchant employees of the Transmission Provider and/or its affiliates and transmission/reliability employees of the Transmission Provider shall apply to the employees of the Independent Entity.

3.4.2 The Independent Entity shall adopt a policy on conflicts of interest establishing appropriate standards for the professional and financial independence of the Independent Entity, consistent with FERC policies and regulations. In addition, the Independent Entity shall adopt ethics policies and standards for its employees and subcontractors. The Independent Entity, including each member and employee of the Independent Entity's firm shall comply at all times with the conflicts of interest and ethics policies. The Independent Entity's conflict of interest and ethics policies shall be posted on the Transmission Provider's OASIS. The Independent Entity shall also immediately post on the Transmission Provider's OASIS each instance in which it sub-delegates any of its Independent Entity tasks or functions to the Transmission Provider. The Independent Entity's conflict of interest policies shall include provisions protecting against any discrimination by the Independent Entity in favor of third parties for whom the Independent Entity may perform services or enjoy a relationship that inures to the Independent Entity's financial benefit.

3.5 Nothing in this Attachment K shall be deemed (i) to restrict or to prohibit access by the Transmission Provider to transmission facilities owned by the Transmission Provider, or those acting under its authority, when such access is necessary for the Transmission Provider to operate and maintain such transmission facilities, or (ii) to restrict or prohibit the Transmission Provider from taking any actions it believes are reasonably necessary to protect against endangerment to the safety of employees or the public or damage to facilities.

3.6 In order to carry out its responsibilities under this Attachment K, the Independent Entity will have complete access, subject to appropriate confidentiality provisions, to all data and information prepared by or on behalf of or generated for the Transmission Provider's transmission operations personnel that are reasonably necessary to achieve the purposes and objectives of this Attachment K. To the extent that the Independent Entity requires access to data or information obtained by the Transmission Provider from other market participants, including the Transmission Provider's wholesale merchant function employees, such data or information shall be treated as confidential information unless otherwise available from public sources or public disclosures.

4 GENERAL

4.1 The Independent Entity, in consultation with the Transmission Provider and Tariff Participants, shall develop and revise, as appropriate, operating procedures governing its exercise of the responsibilities set out herein ("Operating Procedures"), which shall be made publicly available on the OASIS except to the extent the Independent Entity and the Transmission Provider jointly determine that certain of the procedures should not be made publicly available for security reasons.

4.2 The Independent Entity shall, in consultation with the Transmission Provider and any Tariff Participants, develop and post on the Transmission Provider's OASIS procedures pursuant to which the Transmission Provider, and any interested Tariff Participants may, as provided for herein, meet with representatives of the Independent Entity to discuss, among other things, the Operating Procedures, the Independent Entity's exercise of the responsibilities set out therein, and the division of responsibilities and functions set forth in this Attachment K.

4.2.1. At a reasonable date to be established before the Independent Entity begins operations under this Attachment K, the Independent Entity shall establish a mechanism to review the Operating Procedures and any related protocols with the Transmission Provider and Tariff Participants.

4.2.2. During the first six months of operation, the Independent Entity shall conduct monthly conference calls at which the Independent Entity shall solicit, consider, and respond to the input of the Transmission Provider and Tariff Participants as to the Independent Entity's provisions of the functions under this Attachment K.

4.2.3 During the term of this Agreement, the Independent Entity shall conduct regularly scheduled meetings at which it shall solicit, consider, and respond to the input of the Transmission Provider and Tariff Participants as to the Independent Entity's provision of the functions under this Attachment K. This process shall include an opportunity for both written and verbal input.

4.2.4 No later than six months from its first date of operations under this Attachment K, the Independent Entity shall make available and maintain a section on the Transmission Provider's OASIS (or related website) under which notices to the Transmission Provider and Tariff Participants and input from the Transmission Provider and Tariff Participants on the Independent Entity's role and performance may be posted.

4.3 The Independent Entity shall comply with all applicable Federal or State laws or authorities that would otherwise govern the Transmission Provider in performing the functions provided for herein.

4.4 The Independent Entity shall develop procedures for ensuring the confidentiality of any confidential information or materials, including information or materials that include or comprise Critical Energy Infrastructure Information, made available to the Independent Entity by the Transmission Provider or any Tariff Participant.

4.5 The Independent Entity shall take no action, nor request that any power plant operator take any action, that would impair the safety, reliability, or environmental compliance of any such facility. To the extent applicable, the Independent Entity shall perform all of its functions in a manner consistent with all Federal and State regulatory and licensing requirements applicable to the generating facilities, including but not limited to any applicable nuclear power plant license conditions and applicable requirements or orders of the Nuclear Regulatory Commission ("NRC") and licenses and other applicable Federal and State regulatory requirements for hydro-electric facilities.

4.6 The Transmission Provider will not modify the TSR Processing Criteria, the Transmission Study Criteria, or the Interconnection Study Criteria, without first providing sixty (60) days notice to the Independent Entity. The Independent Entity may independently propose that the Transmission Provider modify the TSR Processing Criteria, the Transmission

Study Criteria, or the Interconnection Study Criteria by raising such a proposal in a report to the Transmission Provider and Tariff Participants. The Independent Entity will post on OASIS a notice of any modification to the relevant criteria. The Transmission Provider will remain the sole entity with the right to file with FERC modifications to the Tariff and the LGIP under Section 205 of the Federal Power Act.

4.7 The Independent Entity shall not have the right, nor shall it be authorized, under Section 205 of the Federal Power Act to file or make application to FERC to propose revisions to this Attachment K or any rates, terms, or conditions of the Tariff. Nothing in this Attachment K shall be interpreted or construed as in any way limiting the rights of the Transmission Provider under Section 205 of the Federal Power Act to file or make application to FERC to propose revisions to this Attachment K or any rates, terms, or conditions of the Tariff.

4.8 Except as otherwise provided herein, in the event that any dispute arises relating to this Attachment K between the Independent Entity and the Transmission Provider, or between the Independent Entity and any Tariff Participant, the dispute shall first be referred to an executive management representative of each party. If the executive management representatives are unable to resolve the dispute within ten (10) business days, the dispute resolution provisions of the Tariff shall apply, provided, however, that nothing in this Attachment K shall limit or abridge any rights of any Tariff Participant to seek any other relief that may be available under the Tariff.

4.9 In the event that the Independent Entity believes that any provision of this Attachment K is limiting or restricting the Independent Entity's ability to perform the functions provided for herein, it shall bring such concerns to the attention of the Transmission Provider and, if the Transmission Provider agrees, the Transmission Provider shall file or make application to FERC to propose revisions to this Attachment K. If the Transmission Provider disagrees as to the revisions proposed by the Independent Entity, the Independent Entity shall prepare a detailed analysis supporting such proposed revisions and the Transmission Provider shall submit to FERC such detailed analysis as well as the reason(s) that the Transmission Provider disagrees as to the revisions proposed by the Independent Entity, and FERC may act on such submissions pursuant to Section 206 of the Federal Power Act; provided, however, that the Independent Entity shall not propose to alter, nor shall it propose that the Transmission Provider file or make application to FERC to alter, the scope or nature of the functions provided for under this Attachment K.

5 GENERAL RESPONSIBILITIES OF THE INDEPENDENT ENTITY, THE TRANSMISSION PROVIDER, GENERATION OWNERS AND LOAD SERVING ENTITIES

5.1 The responsibilities and duties of the Independent Entity and Transmission Provider are set forth in this Attachment K. The Transmission Provider also shall participate in any ad hoc working groups established by the Independent Entity

5.2 Generation Owners shall have the following responsibilities:

5.2.1 Notify the Independent Entity of any applicable NRC and/or other applicable requirements that govern the operation of any generating facilities interconnected with the Transmission System.

5.2.2 Submit and coordinate unit schedules as necessary to permit the Independent Entity to assess transmission transfer capability and transmission reliability.

5.2.3 Participate in ad hoc working groups established by the Independent Entity.

5.3 Load Serving Entities shall have the following responsibilities:

5.3.1 Submit operating data as the Independent Entity may require to perform its various functions.

5.3.2 Participate in ad-hoc working groups established by the Independent Entity.

6 PROCESSING OF TRANSMISSION SERVICE REQUESTS, DETERMINATION OF TRANSFER CAPABILITY, AND OASIS MANAGEMENT

Transmission Service Requests

6.1 The Independent Entity will process and evaluate (i.e., grant or deny) all TSRs, including those transactions associated with network service and point-to-point service agreements, on a non-discriminatory basis consistent with the Tariff, the TSR Processing Criteria, the Transmission Study Criteria, and accepted utility practice. The Independent Entity shall be responsible for documenting all transmission service requests under the Tariff, the disposition of such requests, and any supporting data required to support the decision with respect to such requests. The Independent Entity's responsibilities in processing and evaluating TSRs include the following:

6.1.1 Collecting all necessary information for the processing and evaluation of a TSR;

6.1.2 Coordinating as necessary with the Transmission Provider when processing requests for service into and out of transmission facilities or distribution facilities;

6.1.3 Determining that all preconditions necessary for a TSR to be considered a Completed Application have been met;

6.1.4 Maintaining appropriate TSR queues for Short-Term and Long-Term TSRs;

6.1.5 Determining whether sufficient transmission capability exists to grant or deny a TSR;

6.1.6 Providing and executing SIS Agreements and Facilities Studies Agreements;

6.1.7 Performing SISs, consistent with Sections 6.4.1 to 6.4.5 of this Attachment K, as necessary to further evaluate whether sufficient transmission capability exists to accommodate a TSR or what additional facilities might be, subject to further review in a Facilities Study, required to allow the granting of a request;

6.1.8 Performing SISs in response to requests to designate new Network Resources under Section 30 of the Tariff, including requests by the Transmission Provider's wholesale merchant function on behalf of Native Load Customers, and verifying that applicable Tariff requirements have been met;

6.1.9 Providing all notices related to the processing and evaluation of a TSR to the Transmission Customer;

6.1.10 Independently reviewing the Transmission Provider's description of the ATC Methodology, SIS Criteria, Facilities Study Criteria, and TSR Processing Criteria to ensure that these criteria are sufficiently defined for Transmission Customers to understand how TSRs are processed and evaluated. If the Independent Entity concludes that additional explanatory detail is required, the Transmission Provider will modify the appropriate business practice documents to include the additional detail. The Independent Entity will post on OASIS the final versions of the criteria, including the Transmission Provider's local reliability criteria, subject to the confidentiality provisions of Section 3.6 herein.

6.1.11 Independently reviewing data, information and analyses, including Facilities Studies, provided or performed by the Transmission Provider;

6.1.12 Ensuring that the TSR Processing Criteria and the Transmission Study Criteria are posted on OASIS and are sufficiently detailed so that the evaluation and processing of TSRs is transparent and understandable, subject to the confidentiality provisions of Section 3.6 herein;

6.1.13 Responding to inquiries by Transmission Customers regarding TSRs concerning the functions performed by the Independent Entity as set forth in this Attachment K;

6.1.14 Determining the amount and applicability of Ancillary Services under Schedules 1-6 of the Tariff that are needed or required for each transaction by Transmission Customers to comport with reliability guidelines; and

6.1.15 Billing and normal collection of the applicable charges for SIS and Facilities Studies.

6.2 The processing and evaluation of TSRs requires coordination between the Independent Entity and the Transmission Provider. The Transmission Provider shall be responsible for the following functions associated with the processing and evaluation of TSRs, and the Independent Entity will ensure that these functions are performed on a non-discriminatory basis consistent with the TSR Processing and Transmission Study Criteria:

6.2.1 Providing data inputs and other information and analyses required by the Independent Entity to study individual TSRs;

6.2.2 Tendering, entering into, and filing all Transmission Service Agreements in accordance with the Tariff;

6.2.3 Entering into any Facilities Study agreement with the Independent Entity and the Transmission Customer;

6.2.4 Performing Facilities Studies consistent with Sections 6.4.6 to 6.4.10 herein;

6.2.5 Billing and collecting the applicable charges for transmission service under the Tariff and Ancillary Services under Schedules 1-6 of the Tariff; and

6.2.6 Supplying the Independent Entity with detailed descriptions of the current Transmission Study Criteria and TSR Processing Criteria, including: (i) the Transmission Provider's current Tariff; (ii) applicable NERC Reliability Standards and SERC supplements to those standards; (iii) the Transmission Provider's local reliability criteria; and (iv) the Transmission Provider's business practices related to processing TSRs and OASIS administration, and the methodologies for calculating ATC values and conducting SISs and Facilities Studies.

TSR Processing Criteria

6.3 **Base Case Model Development:** Once the Base Case Model is complete, the Independent Entity will participate with the Transmission Provider in any additional regional model development processes necessary to create updated quarterly and monthly regional models from the seasonal and annual models. These models, which are updated quarterly or monthly, will serve as the basis for the annual, seasonal, monthly, or daily Base Case Models for the Transmission System used to evaluate TSRs.

6.3.1 In order to develop the regional models for the Transmission System referenced above, the Transmission Provider will provide to the Independent Entity and other modeling group participants such data and information as may be necessary to prepare and update the models. The Independent Entity will review the data inputs provided by the Transmission Provider to ensure that the data inputs and resulting models are consistent with the Transmission Study Criteria.

6.4 **Studies for Long-Term TSRs:** All Long-Term TSRs will be evaluated in accordance with the Tariff. If a SIS indicates that additions or upgrades are needed to accommodate the TSR, the Transmission Customer may request a Facilities Study. The division of responsibilities and duties related to such studies are described in this Section 6.4.

System Impact Study:

6.4.1 If necessary, the Independent Entity shall inform the Transmission Customer of the need for an SIS and provide the Transmission Customer with the standard form SIS Agreement to be executed by the Independent Entity and the Transmission Customer. The SIS Agreement shall obligate the Transmission Customer to pay for the actual cost of the SIS, including any costs incurred by the Independent Entity or the Transmission Provider associated with performing their respective functions under Sections 6.4.1 to 6.4.5 herein. The Independent Entity will be responsible for determining whether the Transmission Customer has timely complied with all requirements necessary for an SIS and for a request to remain a Completed Application. The Independent Entity will provide a copy of the executed SIS Agreement to the Transmission Provider.

6.4.2 After confirming that all applicable requirements have been met by the Transmission Customer, the Independent Entity will perform or cause to be performed the required SIS. If the SIS is performed by someone other than the Independent Entity, the Independent Entity still retains the ultimate responsibility and authority for the study. To perform the SIS, the Independent Entity will use the current set of applicable Base Case Models developed pursuant to Section 6.4 herein. The Independent Entity will update the applicable Base Case Models to reflect then-current data from the Transmission Provider's OASIS regarding additional Long-Term TSRs, including new or expired rollover rights. The Independent Entity will perform the SIS as set forth in the SIS Criteria and will ensure that the Base Case Models, including any updates thereto, are consistent with the SIS Criteria.

6.4.3 The Independent Entity will provide the Transmission Provider or affected third-party Transmission Provider with an initial draft of the SIS report including a list of any constrained transmission elements. The Transmission Provider or affected third-party Transmission Provider will have the opportunity to review and comment on the report and will be responsible for developing a mitigation plan to address any constrained transmission elements. The Independent Entity will review the affected Transmission Provider's mitigation plan and will include the mitigation plan and the Transmission Provider's comments in the final SIS report provided to the Transmission Customer.

6.4.4 The Independent Entity, in conjunction with the Transmission Provider, will use due diligence to finalize the required SIS in accordance with the Tariff and will provide all notices to the Transmission Customer required under the Tariff. The Independent Entity will post the SIS on OASIS and respond to requests for work papers supporting the SIS. If the Transmission Provider and the Independent Entity cannot resolve any disagreements regarding the SIS, the Independent Entity will modify the draft SIS report to identify the areas of disagreement and will provide this SIS report to the Transmission Customer by posting on OASIS.

6.4.5 If the Transmission Provider and the Independent Entity agree that no additions or upgrades to the Transmission System are needed to accommodate the TSR, and the Independent Entity has determined that the Transmission Customer has met the necessary Tariff requirements, the Transmission Provider will provide the Transmission Customer with a Transmission Service Agreement to be executed by the Transmission Provider and the Transmission Customer. The Transmission Customer may request that the Transmission Provider file an unexecuted Transmission Service Agreement with FERC in accordance with the Tariff if: (i) the Transmission Provider and the Independent Entity cannot agree on whether any additions or upgrades to the Transmission System are needed to accommodate the TSR; (ii) the Transmission Customer does not accept the results of the SIS; or (iii) the Transmission Provider and the Transmission Customer cannot agree on the terms and conditions of the Transmission Service Agreement. If the Transmission Provider and the Independent Entity cannot agree on the scope of the additions or upgrades to the Transmission System that are needed to accommodate the TSR, or if the Transmission Customer does not accept the scope of the necessary additions or upgrades, the parties shall attempt to resolve any such disagreement through the more detailed Facilities Study process in Section 0 below if the Transmission Customer elects to undertake such a study.

Facilities Study:

6.4.6 If a SIS indicates that additions or upgrades are needed to accommodate the TSR, the Independent Entity will provide the Transmission Customer with the standard form Facilities Study Agreement to be executed by the Independent Entity, the Transmission Provider, and the Transmission Customer. The Facilities Study Agreement shall obligate the Transmission Customer to pay for the actual cost of the Facilities Study, including any costs incurred by the Independent Entity or the Transmission Provider associated with performing their respective functions under Sections 6.4.6 to 6.4.10 herein. The Independent Entity will be responsible for determining whether the Transmission Customer has timely complied with all requirements necessary for a Facilities Study and for a request to remain a Completed Application.

6.4.7 After confirming that all applicable requirements have been met by the Transmission Customer, the Independent Entity shall direct the Transmission Provider to perform a Facilities Study. The Independent Entity will provide the Transmission Provider with the updated Base Case Models used by the Independent Entity in performing the SIS, including any additional data that the Independent Entity determines may have material impact on the Facilities Study results. The Independent Entity shall direct the Transmission Provider to determine the scope and estimate the cost of the additions or upgrades to the Transmission System needed to accommodate the TSR. The Transmission Provider shall use the updated Base Case Models provided by the Independent Entity as the basis for this determination and shall make this determination on a non-discriminatory basis consistent with the Facilities Study Criteria. The Transmission Provider will provide the Independent Entity with its determination of the scope and estimate of the cost of the necessary additions or upgrades and, upon request, supporting documents and work papers.

6.4.8 The Independent Entity will review the Transmission Provider's determination regarding the scope and cost of the necessary additions or upgrades. To the extent necessary, the Independent Entity shall coordinate the Facilities Study with other affected transmission providers and conduct any meetings between the Transmission Provider and any other affected transmission providers. The Independent Entity will prepare an initial draft of the Facilities Study report. The

Transmission Provider will have the opportunity to review and comment on the report and its comments will be included in the final Facilities Study report provided to the Transmission Customer. If the Independent Entity and the Transmission Provider cannot resolve any disagreements regarding the Facilities Study, the Independent Entity will modify the draft Facilities Study report to identify the areas of disagreement and will provide this Facilities Study report to the Transmission Customer.

6.4.9 The Independent Entity, in conjunction with the Transmission Provider, will use due diligence to finalize the required Facilities Study in accordance with the Tariff and will provide all notices to the Transmission Customer required under the Tariff. The Independent Entity will provide the Transmission Customer with the final Facilities Study report and will respond to requests for work papers supporting the Facilities Study.

6.4.10 If the Independent Entity and the Transmission Provider agree on the final Facilities Study, and the Transmission Customer accepts the final Facilities Study, and the Independent Entity has determined that the Transmission Customer has met the necessary Tariff requirements, the Transmission Provider will provide the Transmission Customer with a Transmission Service Agreement to be executed by the Transmission Provider and the Transmission Customer. If the Independent Entity and the Transmission Provider cannot agree, or the Transmission Customer does not accept the final Facilities Study, or if the Transmission Provider and the Transmission Customer cannot agree on the terms and conditions of the Transmission Service Agreement, the Transmission Customer may request that the Transmission Provider file an unexecuted Transmission Service Agreement with FERC in accordance with the Tariff.

6.5 **Studies for Short-Term TSRs:** The Independent Entity will evaluate all Short-Term TSRs in accordance with the ATC Methodology using the Base Case Models described in Section 6.3.

TTC and ATC Calculation

6.6 The Independent Entity shall calculate TTC and ATC in accordance with the provisions of Attachment C-3 of the Tariff.

6.6.1 ATC will be calculated by the Independent Entity on a Control Area-to-Control Area basis for the Transmission Provider's Control Area interfaces.

6.6.2 The Independent Entity will be responsible for ensuring that ATC values are calculated on a nondiscriminatory basis consistent with the ATC Methodology. The Independent Entity's responsibilities in calculating ATC values will include (a) reviewing the data inputs to the ATC Base Case Models; (b) responding to Transmission Customer inquiries regarding the ATC process; (c) requiring modifications to the Base Case Models or data inputs to the extent such modifications are necessary to ensure consistency with the ATC Methodology as provided in Section 6.3.1 herein; and (d) requiring the recalculation (or resynchronization) of ATC values after modifications made under Section 6.6.6 are implemented.

6.6.3 ATC will be posted based in a manner that recognizes contract path limitations for so long as the contract-path basis is the prevailing mechanism for reserving transmission service under the Tariff.

6.6.4 The Independent Entity shall calculate the ATC for prospective Firm Point-to-Point Transmission Service in a manner that does not assume congestion management options, such as the redispatch of generation to provide such Firm Point-to-Point Transmission Service.

6.6.5 The Transmission Provider will supply data inputs and information necessary for the Base Case Models, and will assist the Independent Entity to the extent requested in responding to Transmission Customer inquiries. The Independent Entity will ensure that the Transmission Provider performs these functions on a nondiscriminatory basis consistent with the ATC Methodology.

6.6.6 The Independent Entity will have authority to direct the Transmission Provider to modify the Base Case Models or data inputs to ensure that the ATC values are calculated in a manner consistent with the ATC Methodology posted on OASIS. If the Independent Entity and the Transmission Provider cannot agree on a modification to the Base Case Models or data inputs proposed by the Independent Entity under this Section 6.6, the Independent Entity's position shall control and serve as the basis for evaluating TSRs pending resolution of any such disagreement. To the extent the Independent Entity directs a modification under this section, the Independent Entity shall also have the authority to direct the resynchronization of ATC values after the modification is implemented.

6.7 The Independent Entity shall review all data received from Reliability Coordinators, Control Areas, independent transmission system operators, regional reliability councils, or other security entities that impact ATC calculations, and shall share such ATC calculations with those Reliability Coordinators, Control Areas, transmission providers, independent transmission system operators, regional reliability councils, or other security entities that are or may be impacted by such ATC calculations.

OASIS Administration

6.8 **Independent Entity Duties and Responsibilities:** The Independent Entity will administer the Transmission Provider's existing OASIS node for purposes of processing and evaluating TSRs and ensuring compliance with the Transmission Provider's obligation to publicly post transmission-related information pursuant to the Commission's OASIS regulations. The Independent Entity's responsibilities and duties in administering OASIS will include the following:

6.8.1 Performing the duties of a Responsible Party as defined in the Commission's OASIS regulations, 18 C.F.R. § 37.5; and

6.8.2 Posting information required to be on the Transmission Provider's OASIS under the Commission's OASIS regulations, 18 C.F.R. § 37.6.

6.9 **Transmission Provider Duties and Responsibilities:** The Transmission Provider will be responsible for the following functions associated with OASIS operations, and the Independent Entity will ensure that these functions are performed consistent with the TSR Processing Criteria and the Commission's OASIS regulations:

6.9.1 Providing the Independent Entity with the information necessary to comply with the posting requirements.

Transmission Scheduling

6.10 The Independent Entity shall act as the single contact for Transmission Customers scheduling transactions into, out of, or through the Transmission Provider's Control Area.

6.11 The Independent Entity shall process transmission reservations in accordance with currently accepted industry practice(s).

6.12 When a Transmission Customer submits an electronic tag to implement a transaction for a previously accepted transmission reservation, the Independent Entity shall be responsible for evaluating the tag to ensure that it contains the proper transmission reservation information. The Independent Entity is responsible for updating the electronic tagging system based upon such review.

6.13 When a Transmission Customer submits an electronic tag to implement a transaction for a previously accepted transmission reservation, the Transmission Provider shall be responsible for evaluating the tag to ensure that implementation of such transaction will not have adverse impact on system reliability. The Transmission Provider is responsible for updating the electronic tagging system based upon such review.

6.14 As operator of the transmission system, the Transmission Provider has responsibility for implementing approved tags (entering the tags into the energy management system), and verifying the resulting schedule with adjacent control areas.

7 GENERATOR INTERCONNECTIONS

7.1 Independent Entity Duties and Responsibilities: The Independent Entity shall process all generation interconnection requests and perform generation interconnection impact studies in a nondiscriminatory manner in accordance with the LGIP and the Transmission Provider's Interconnection Study Criteria. The Independent Entity will have authority to interpret and apply the guidelines, and shall have responsibility for administration of the Transmission Provider's LGIP, including queuing of interconnection requests, completion of specified studies associated with interconnection requests, and development of the transmission system modeling process, software, and assumptions used to evaluate requests to interconnect to the Transmission Provider transmission system. The Independent Entity's responsibilities in processing and evaluating Interconnection Requests include the following:

7.1.1 Collecting from the Interconnection Customer and the Transmission Provider all necessary information for the processing and evaluation of an Interconnection Request;

7.1.2 Determining that all preconditions necessary for a valid Interconnection Request have been met;

7.1.3 Performing Interconnection Feasibility Studies, Interconnection SISs, and Optional Interconnection Studies and coordinating such studies with Affected Systems;

7.1.4 Maintaining and administering a queue for Interconnection Study requests;

7.1.5 Posting on the Transmission Provider's OASIS a list of Interconnection Requests and related information as required under the LGIP;

7.1.6 Providing and executing Interconnection Study Agreements and Facility Study Agreements;

7.1.7 Providing all notices related to the processing and evaluation of an Interconnection Request to the Interconnection Customer;

7.1.8 Independently reviewing the Transmission Provider's description of the Interconnection Study Criteria to ensure that these criteria are sufficiently defined for Interconnection Customers to understand how Interconnection Requests are processed and evaluated. If the Independent Entity concludes that additional explanatory detail is required, the Transmission Provider will modify the appropriate business practice documents to include the additional detail. The Independent Entity will post on OASIS the final versions of the criteria, subject to the confidentiality provisions of Section 3.6 herein;

7.1.9 Independently reviewing data, information, and analyses, including Interconnection Facilities Studies, provided or performed by the Transmission Provider;

7.1.10 Responding to inquiries by Interconnection Customers.

7.2 Transmission Provider Duties and Responsibilities: The processing and evaluation of Interconnection Requests requires coordination between the Transmission Provider and the Independent Entity. The Transmission Provider will be responsible for the following functions associated with the processing and evaluation of Interconnection Requests, and the Independent Entity will ensure that these functions are performed consistent with the LGIP and the Interconnection Study Criteria:

7.2.1 Providing data inputs, information, and analyses required by the Independent Entity to perform Interconnection Studies and process Interconnection Requests;

7.2.2 Entering into and filing all Interconnection Facilities Study Agreements and Large Generator Interconnection Agreements in accordance with the Tariff;

7.2.3 Supplying the Independent Entity with the Interconnection Study Criteria, including descriptions or copies of: (i) the LGIP and LGIA provisions applicable to the performance of Interconnection Studies; (ii) applicable NERC Reliability Standards and SERC supplements to those standards; (iii) the Transmission Provider's business practices related to Interconnection Studies; and (iv) the Transmission Provider's local reliability criteria; and

7.2.4 Performing Interconnection Facilities Studies consistent with Section 7.6 herein.

7.3 Studies for Interconnection Service Requests: The LGIP provisions of the Tariff shall determine the studies necessary to interconnect with the Transmission System. The Independent Entity will be responsible for coordinating all Interconnection Studies with any Affected Systems and conducting all meetings between the Affected Systems, the Transmission Provider and the Interconnection Customer, in accordance with the provisions of the LGIP. The division of additional responsibilities in performing Interconnection Studies is described below.

7.4 Interconnection Feasibility Study

7.4.1 Pursuant to the LGIP, the Independent Entity shall provide the Interconnection Customer with an Interconnection Feasibility Study Agreement to be executed by the Interconnection Customer and the Independent Entity. The Interconnection Feasibility Study Agreement shall obligate the Interconnection Customer to pay for the actual cost of the Interconnection Feasibility Study, including any costs incurred by the Independent Entity or the Transmission Provider associated with performing their respective functions under Sections 7.4.1 to 7.4.3 herein. The Independent Entity will be responsible for determining whether the Interconnection Customer has timely complied with all requirements necessary for an Interconnection Feasibility Study and a valid Interconnection Request, as provided in the LGIP. The Independent Entity will provide a copy of the executed Interconnection Feasibility Study Agreement to the Transmission Provider.

7.4.2 After confirming that all applicable requirements have been met by the Interconnection Customer, the Independent Entity will perform or cause to be performed the required Feasibility Study, including any Re-Studies. If the Feasibility study is performed by someone other than the Independent Entity, the Independent Entity still retains the ultimate responsibility and authority for the study. To perform the Feasibility Study, the Independent Entity will use the current set of applicable Base Case Models developed pursuant to Section 8.5 herein. The Independent Entity will update the applicable Base Case Models to reflect then-current data from the Transmission Provider's OASIS regarding additional Long-Term TSRs, including new or expired rollover rights. The Independent Entity will perform the Feasibility Study as set forth in the Interconnection Study Criteria and will ensure that the Base Case Models, including any updates thereto, are developed as set forth in the Interconnection Study Criteria. The Independent Entity will provide the Transmission Provider with an initial draft of the Feasibility

Study report, and the Transmission Provider will have the opportunity to review and comment on the report.

7.4.3 The Independent Entity will use Reasonable Efforts to finalize the Feasibility Study in accordance with the LGIP provisions of the Tariff and will provide all notices to the Interconnection Customer required in that section. The Independent Entity will be responsible for responding to requests for work papers or other supporting documentation under the LGIP. If the Transmission Provider and the Independent Entity cannot resolve any disagreements regarding the Feasibility Study, the Independent Entity will modify the draft Feasibility Study report to identify the areas of disagreement and will provide this Feasibility Study report to the Interconnection Customer. If the Transmission Provider, the Independent Entity, and the Interconnection Customer ultimately cannot agree on the final Interconnection Feasibility Study report, Section 13.5 of the LGIP will apply.

7.5 Interconnection System Impact Study

7.5.1 Pursuant to the LGIP, the Independent Entity shall provide the Interconnection Customer with the Interconnection SIS Agreement to be executed by the Independent Entity and the Interconnection Customer. The Interconnection SIS Agreement shall obligate the Interconnection Customer to pay for the actual cost of the Interconnection SIS, including any costs incurred by the Independent Entity or the Transmission Provider associated with performing their respective functions under Section 7.5 herein. The Independent Entity will be responsible for determining whether the Interconnection Customer has timely complied with all requirements necessary for an Interconnection SIS and for a valid Interconnection Request, as set forth in the LGIP. The Independent Entity will provide a copy of the executed Interconnection SIS Agreement to the Transmission Provider.

7.5.2 After confirming that all applicable requirements have been met by the Interconnection Customer, the Independent Entity shall perform or cause to be performed the required Interconnection SIS, including any Re-Studies. If the Interconnection SIS is performed by someone other than the Independent Entity, the Independent Entity still retains the ultimate responsibility and authority for the study. To perform the Interconnection SIS, the Independent Entity will use the current set of applicable Base Case Models. The Independent Entity will update the applicable Base Case Models to reflect then-current data from the Transmission Provider's OASIS regarding additional Long-Term TSRs, including new or expired rollover rights. The Independent Entity will perform the Interconnection SIS as set forth in the Interconnection Study Criteria and will ensure that the Base Case Models, including any updates thereto, are developed as set forth in the Interconnection Study Criteria.

7.5.3 The Independent Entity will provide the Transmission Provider or other Affected System with an initial draft of the Interconnection SIS report, including a list of any constrained transmission elements. The Transmission Provider will have the opportunity to review and comment on the report and will be responsible for developing a mitigation plan to address any constrained transmission elements. The Independent Entity will review the Transmission Provider's mitigation plan and will include the mitigation plan and the Transmission Provider's comments in the final Interconnection SIS report provided to the Interconnection Customer.

7.5.4 The Independent Entity, in conjunction with the Transmission Provider, will use Reasonable Efforts to finalize the required Interconnection SIS in accordance with the LGIP and will provide all notices to the Interconnection Customer required by the LGIP. The Independent Entity will be responsible for responding to requests for work papers supporting the Interconnection SIS. If the Transmission Provider and the Independent Entity cannot resolve any disagreements regarding the Interconnection SIS, the Independent Entity will modify the draft Interconnection SIS report to identify the areas of disagreement and will provide this Interconnection SIS report to the Interconnection Customer. If the Transmission Provider, the Independent Entity, and the Interconnection Customer ultimately cannot agree on the final Interconnection SIS report, Section 13.5 of the LGIP will apply.

7.6 Interconnection Facilities Study

7.6.1 Pursuant to the LGIP provisions of the Tariff, the Independent Entity will tender the Interconnection Facilities Study Agreement to the Interconnection Customer to be executed by the Independent Entity, the Transmission Provider, any Affected System, and the Interconnection Customer. The Interconnection Facilities Study Agreement shall obligate the Interconnection Customer to pay for the actual cost of the Interconnection Facilities Study, including any costs incurred by the Independent Entity or the Transmission Provider associated with performing their respective functions under Section 7.6 herein.

7.6.2 After confirming that all applicable requirements have been met by the Interconnection Customer, the Independent Entity shall direct the Transmission Provider to perform an Interconnection Facilities Study. The Independent Entity will provide the Transmission Provider with the relevant SIS data used by the Independent Entity in performing the Interconnection SIS, including any additional data that the Independent Entity determines may have material impact on the Interconnection Facilities Study results. The Independent Entity shall direct the Transmission Provider to determine the equipment, engineering, procurement, and construction work necessary to implement the conclusions in the Interconnection SIS. The Transmission Provider shall use the relevant SIS data provided by the Independent Entity as the basis for this determination and shall make this determination consistent with the Interconnection Study Criteria. The Transmission Provider will provide the Independent Entity with its determination and, upon request, supporting documents and work papers.

7.6.3 The Independent Entity will review the Transmission Provider's determination regarding the equipment, engineering, procurement, and construction work necessary to implement the conclusions in the Interconnection SIS. The

Independent Entity will prepare an initial draft of the Interconnection Facilities Study report. The Transmission Provider will have the opportunity to review and comment on the report and the Transmission Provider's comments will be included in the final Interconnection Facilities Study report provided to the Interconnection Customer. If the Independent Entity and the Transmission Provider cannot resolve any disagreements regarding the Interconnection Facilities Study, the Independent Entity will modify the draft Interconnection Facilities Study report to identify the areas of disagreement and will provide this Interconnection Facilities Study report to the Interconnection Customer.

7.6.4 The Independent Entity, in conjunction with the Transmission Provider, will use Reasonable Efforts to finalize the required Interconnection Facilities Study in accordance with the LGIP and will provide all notices to the Interconnection Customer required in the LGIP. The Independent Entity will be responsible for providing the Interconnection Customer with the final Interconnection Facilities Study report and responding to requests for work papers and supporting documentation for the Interconnection Facilities Study.

7.6.5 If the Independent Entity and the Transmission Provider agree on the final Facilities Study, and the Interconnection Customer accepts the final Facilities Study, and the Independent Entity has determined that the Interconnection Customer has met the necessary LGIP requirements, the Transmission Provider will provide the Interconnection Customer with a LGIA to be executed by the Transmission Provider and the Interconnection Customer. If the Independent Entity and the Transmission Provider cannot agree, or the Interconnection Customer does not accept the final Interconnection Facilities Study, or if the Transmission Provider and the Interconnection Customer cannot agree on the terms and conditions of the LGIA, the parties may attempt to resolve the dispute pursuant to Section 13.5 of the LGIP or the Interconnection Customer may request that the Transmission Provider file an unexecuted LGIA with FERC in accordance with Section 11.3 of the LGIP.

7.7 Optional Interconnection Study: If the Interconnection Customer requests an Optional Interconnection Study, the division of responsibilities between the Transmission Provider and the Independent Entity shall be the same as for the Interconnection SIS.

8 [RESERVED].

ATTACHMENT ~~N~~L

~~Procedures for Addressing Parallel Flows~~

THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION TRANSMISSION LOADING RELIEF PROCEDURES AND PROCEDURES FOR ADDRESSING PARALLEL FLOWS

The North American Electric Reliability Corporation's ("NERC")'s ~~TLR~~Transmission Loading Relief ("TLR") Procedures originally filed March 18, 1998, which are now the mandatory Reliability Standards that address TLR, and any amendments thereto, on file and accepted by the Commission, are hereby incorporated and made part of this tariff. See www.nerc.com for the current version of the NERC's TLR Procedures.

Notice of Adoption of Local Transmission Loading Relief Procedure in CP&L Zone

Pursuant to NERC Reliability Standard IRO-006-3 – Reliability Coordination – TLR, R2, CP&L adopts a local TLR procedure that will be used to supplement the current NERC TLR Procedures.

CP&L will implement this procedure with neighbors signing an agreement agreeing to the local procedure. CP&L will use the current NERC TLR Procedure that has a 5% Transfer Distribution Factor ("TDF") for determining Non-Firm schedule curtailment.

If the NERC TLR Procedure (NERC Standard IRO-006-3) does not provide the required relief from Non-Firm schedules, then the parties will curtail Non-Firm schedules down to 3% TDF in accordance with local procedures as described in section R2 of the NERC TLR Standard.

This will be done for any tagged schedule that has a 3% TDF that can provide relief on the flowgate, where either CP&L or the reciprocal party is a source or sink for the schedule.

If any schedules are identified that curtailment will provide relief on the flowgate, then that party will curtail the schedules until the flow is reduced on the flowgate or all of the schedules have been curtailed.

The local transmission loading relief procedure described above shall be used to supplement, and not as a substitute for, the Interconnection-wide procedure. The parties agree that they will comply with the NERC TLR Procedure and all NERC Reliability Standards at all times.

ATTACHMENT ~~O~~M

SMALL GENERATOR INTERCONNECTION PROCEDURES (SGIP)

~~**Small Generator Interconnection Procedures (SGIP)**~~

(For Generating Facilities No Larger Than 20 MW)

The remaining pages to Attachment M
contain no changes of substance and are not included.

~~ATTACHMENT N~~

~~Procedures for Addressing Parallel Flows~~

ATTACHMENT ~~K~~N-1

~~**Transmission Planning Process**~~

TRANSMISSION PLANNING PROCESS
(CP&L Zone and DEC Zone)

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" coordination activities with transmission providers located outside their Control Areas. Such activities include participation in SERC and the Southeast Inter-Regional Participation Process (Appendix 1), which focus on reliability assessments and economic studies respectively.

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 Transmission Customers under this Tariff.

2.1 The *North Carolina Transmission Planning Collaborative 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 Anyone may participate in TAG meetings and sign-up to receive TAG communications. The TAG is comprised of TAG participants. An employee or agent of a NCTPC Participant who 1) performs or supervises transmission planning activities or 2) is a member of the OSC or PWG may not be a TAG participant, but employees or agents of NCTPC Participants that perform activities other than transmission planning activities may be TAG participants.

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 NCTPC Participants to aid in the development of an annual Collaborative Transmission Plan. The TAG participants may propose enhanced transmission access projects for evaluation as described in Section 4.2.2 hereof. The TAG participants select which of those projects should be evaluated through the TAG Sector Voting Process. The TAG participants also provide input on the annual study scope elements of both the Reliability Planning Process as well as the Enhanced Transmission Access Planning Process, including input on the following: Study Assumptions; Study Criteria; Study Methodology; Case Development and Technical Analysis; Problem Identification; Assessment and Development of Solutions (including proposing alternative solutions for evaluation); Comparison and Selection of the Preferred Transmission Plan; and the Transmission Plan Study Results Report. A full list of the TAG's responsibilities is found in *Scope - Transmission Advisory Group,* which is located on the NCTPC Website.

2.4.3.2 The ITP will chair the TAG meetings and serve as a facilitator for the group. TAG decision-making is by consensus among the TAG participants. However, in the event consensus cannot be reached, voting will be conducted through the TAG Sector Voting Process. The ITP will provide notice to the TAG participants in advance of the TAG meeting that specific votes will be taken during the TAG meeting.

2.4.3.3 Only TAG participants attending the meeting (in person or by telephone) will be allowed to participate in the TAG Sector Voting Process. No voting by proxy is permitted.

2.4.4 TAG Sector Voting Process.

2.4.4.1 In order for a TAG participant to participate in the TAG Sector Voting Process, the TAG participant must have registered with the ITP at least two weeks prior to the first meeting at which the TAG participant intends to vote. Such web-based registration will require the TAG participant to provide the following information to the ITP: name, home or business address, place of employment (if any), email address (if any), and telephone number. The registration form will require the TAG participant to indicate whether the TAG participant is registering as an "Individual" or as an agent or employee of a "TAG Sector Entity." If the TAG participant registers as an agent, member, or employee of a TAG Sector Entity, s/he must identify such TAG Sector Entity. An individual TAG participant may register as an agent, member, or employee of more than one TAG Sector Entity.

2.4.4.2 A TAG Sector Entity may be any organized group (e.g., corporation, partnership, association, trust, agency, government body, etc.) but can not be an individual person. A TAG Sector Entity may be a member of only one TAG Sector. A TAG Sector Entity and its affiliates or member organizations all may register as separate TAG Sector Entities, as long as such affiliates or member organizations meet the definition of a TAG Sector Entity.

2.4.4.3 A TAG Sector Entity should elect to be a member of one of the following TAG Sectors: Cooperative LSEs (that serve load in the NCTPC footprint); Municipal LSEs (that serve load in the NCTPC footprint); Investor-Owned LSEs (that serve load in the NCTPC footprint); Transmission Providers/Transmission Owners (that are not LSEs in the NCTPC footprint); Transmission Customers (a customer taking Transmission Service from at least one Transmission Provider in the NCTPC); Generator Interconnection Customers (a customer taking FERC- or state-jurisdictional generator interconnection service from at least one of the Transmission Providers in the NCTPC); Eligible Customers and Ancillary Service Providers (includes developers; ancillary service providers; power marketers not currently taking transmission service; and demand response providers); and General Public. An Individual is only eligible to join the General Public Sector.

2.4.4.4. Only one individual TAG participant that has registered as an agent or employee of a TAG Sector Entity may vote on behalf of a particular TAG Sector Entity with regard to any particular vote. An individual TAG participant may vote on behalf of more than one TAG Sector Entity, if authorized to do so. Questions to be voted on will be answerable with a Yes or No.

2.4.4.5 If a vote is to be taken, each TAG Sector that has at least one TAG Sector Entity representative, or at least one Individual or TAG Sector Entity representative in the case of the General Public Sector, present will receive a Sector Vote with a worth of 1.00. A Sector Vote is divisible. The vote of each TAG participant eligible to vote in a Sector Vote is not divisible. The vote of each TAG participant in a TAG Sector will be multiplied by 1.00 divided by the total number or TAG participants voting in such Sector to determine how the Sector Vote with a total worth of 1.00 will be allocated between "Sector Yes Votes" and "Sector No Votes." That is, each Sector Vote will be allocated such that the Sector Yes Vote(s) and Sector No Vote(s) totals 1.00. The Sector Yes Vote and Sector No Vote for each TAG Sector will then each be weighted by multiplying each of them by 1.00 divided by the number of TAG Sectors participating in the relevant vote. The results will be called "Weighted Sector Yes Vote" and "Weighted Sector No Vote." The winning position will be the larger of the Weighted Sector Yes Vote and Weighted Sector No Vote. Appendix 3 contains an example of the voting process.

2.4.5. Independent Third Party

2.4.5.1 The ITP facilitates the overall NCTPC Process.

2.4.5.2 A list of the ITP's primary responsibilities is found in *Scope - Planning Working Group* and *Scope - Oversight/Steering Committee.*

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

2.4.5.4 The ITP maintains the NCTPC Website.

2.4.5.5 The ITP's role in decision-making varies based on which group s/he is participating as documented in the NCTPC documents posted on the NCTPC Website.

2.5 Participation of State Regulators

State regulators, including state-sanctioned entities representing the public, like other members of the public, may choose to be TAG participants. State public utility regulatory commissions also may seek to receive periodic status updates and the progress reports on the NCTPC Process. State public utility regulatory commissions may be TAG Sector Entities in the General Public Sector.

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

3.1.2 Information about signing up to be a TAG participant and to receive email communications is posted on the NCTPC Website.

3.1.3 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 generally are open to the public, i.e., TAG participants. When necessary, TAG meetings may be restricted by the ITP to TAG participants that are qualified to receive Confidential Information.

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

In order to ensure comparability, customers taking Network Transmission Service are expected to accurately reflect their demand response resources appropriately in their annual load forecast projections. Customers taking Point-to-Point Transmission Service are expected to accurately reflect their demand response resources in submitting their requests for Transmission Service and in submitting information about potential needs for Point-to-Point Transmission Service. Eligible Customers providing information about potential needs for Point-to-Point Transmission Service are expected to accurately reflect their demand response resources in submitting information. To the extent a TAG participant has a demand response resource or a generation resource that the TAG participant desires the NCTPC to specifically consider as an alternative to transmission expansion, or otherwise in conjunction with the NCTPC Process, such TAG participant sponsoring such demand response resource or generation resource shall provide the necessary information (cost, performance, lead time to install, etc.) in order for the NCTPC to consider such demand response resource or generation resource alternatives comparably with other alternatives.

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. Throughout the Reliability Planning Process, TAG participants (including TAG participants representing transmission solutions, generation solutions, and solutions utilizing demand resources) may participate.

4.2 Overview of Enhanced Transmission Access Planning Process

4.2.1 The ETAP Process is the economic planning process that allows the TAG participants 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* on the NCTPC Website.

4.2.2 The ETAP Process begins with the TAG participants 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 participants early in the annual planning cycle. The form is posted on the NCTPC Website. The PWG will determine if it would be efficient to combine and/or cluster any of the proposed scenarios and will also determine if any of the proposed scenarios are of an Inter-Regional nature. The OSC will direct the TAG participants to submit the Inter-Regional study requests to the Southeast Inter-Regional Participation Process since those studies would have to be evaluated within that forum. Throughout the ETAP Process, TAG participants (including TAG participants representing transmission solutions, generation solutions, and solutions utilizing demand resources) may participate.

4.2.3 The OSC will review the PWG analysis, approve the compiled study list, and provide the study list to the TAG. For the study scenarios that impact the NCTPC region, but are not Inter-Regional in nature, the TAG participants will select a maximum of five scenarios that will be studied within the current NCTPC planning cycle. If consensus cannot be reached as to which scenarios to study, the choice will be resolved through the TAG

Sector Voting Process. The TAG participants may request that the five scenarios be combined or clustered.

4.2.4 There will be no charge to the TAG participants for the five studies selected by the TAG participants. However, if a particular TAG participant wants the NCTPC to evaluate a scenario that was not chosen by the TAG participants, then the TAG participant can request to have the NCTPC conduct the study. The NCTPC will evaluate this request and will conduct the study if the study can be reasonably accommodated, however the cost of conducting this additional study will be allocated to that specific TAG participant.

4.2.5 RETPs

4.2.5.1 As part of the ETAP, TAG participants may propose that a particular RETP be studied. 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. A subscriber to an RETP is under no obligation to use the complete RETP, it may resell its rights to portions of the RETP. An RETP ensures that Point-to-Point Transmission Service can be provided over the Duke and/or Progress systems. The costs of the projects necessary to create an RETP will be subject to the "requestor pays" cost allocation methodology described *infra*. A network customer may seek to use an RETP as the firm Point-to-Point Transmission Service necessary to support a designated network resource external to the Control Area in which its load is located.

4.2.5.2 The TAG participants 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.

4.2.5.3 If an Initial RETP Study is performed, it would identify any transmission system problems/limitations related to the Transmission Providers impacted by the RETP 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 TAG participants 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.

4.2.5.4 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 over the RETP.

4.2.5.5 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 provide the structure whereby Duke and Progress will be able to process these RETP Point-to Point Transmission Service requests 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 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.

4.2.5.6 When the Open Season process is initiated by Duke and Progress, the transmission queue positions for these RETP requests will be established.

4.2.5.7 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) and Service Agreements will be executed (or filed on an unexecuted basis).

4.2.5.8 If an RETP encompasses Transmission Providers outside the NCTPC, the impacted Transmission Providers will 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.

4.2.6 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 participants.

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.

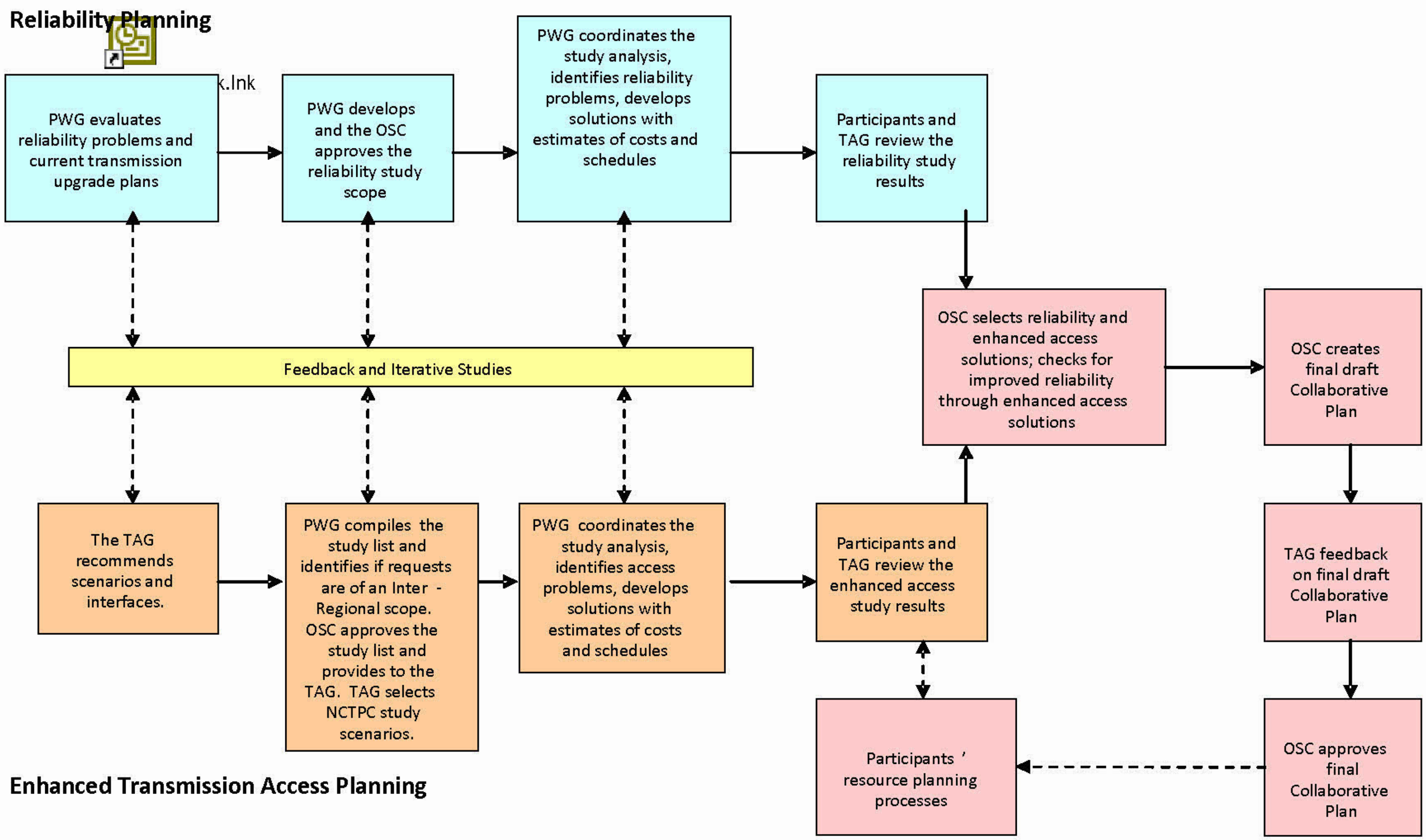
4.3.4 The schedule for all of the activities will be set by the PWG and OSC, but will vary from year to year. The basic order of events is as set forth in Section 5, although the planning process is an iterative one. A list of relevant dates established for the planning cycle will be posted on the NCTPC website.

4.4 Summary Flow Chart of Process

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

Figure 1

North Carolina Transmission Planning Collaborative Process Flowchart



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 participants 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 participants. 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. TAG participants also may, upon request, review the base case models and provide input to the PWG with regard to whether the models 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. TAG participants also may, upon request, request to review the change case models and provide input to the PWG with regard to whether the models 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. TAG participants may review and comment on the planning criteria.

5.2.2 Transmission System planning documents of Duke and Progress will be posted on their respective OASIS sites. Some planning documents may not be posted due to CEII and confidentiality concerns, but will be identified such that they can be requested via the methodology posted on the relevant OASIS.

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. One element of this data collection process will be the annual collection of data from Network Customers required by this Tariff. Any guidelines, data formats, and schedules for any data and information exchanges will be established by the PWG. Aside from the annual submission of data by Network Customers, 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 the TAG participants, and approved by the OSC.

5.3.4 TAG participants 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 their facilities or operations affecting the Transmission Provider's ability to provide service. Network customers may provide revised versions of previously submitted annual data reporting forms.

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 participants.

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 TAG participants to replicate the results of planning studies. A TAG participant seeking data and information that would allow it to replicate the NCTPC planning studies should provide such request to the ITP, who will verify that confidentiality requirements described in Section 9 have been met before providing such information.

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*. TAG participants may review and comment on the study methodology.

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 participants for review and comment.

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 TAG participants are 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 TAG participants will have the opportunity to propose alternative transmission, generation and/or demand response solutions. TAG participants shall provide the necessary information (cost, performance, lead time to install, etc.) for proposed generation and/or demand response alternative solutions so that they may be compared with other alternatives.

5.7.3 All options that satisfactorily resolve an identified reliability problem would be given consideration on a comparable basis.

5.7.4 The Transmission Providers estimate the costs for each of the proposed solutions (e.g., cost, cash flow, present value) and develop a rough schedule estimate to implement the solution. 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 selects the preferred solution by balancing the solutions' costs, benefits, and associated risks. Competing solutions will be evaluated against each other based on a comparison of their relative economics, timing, feasibility, and effectiveness of performance.

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

5.8.3 The PWG provides the OSC and the TAG participants with their recommendations based on this selection process in order to obtain their input.

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 solutions and provides the draft to the OSC for review. The draft Report describes the plan in a manner that is understandable to the TAG participants (*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 solutions including estimates of costs and construction schedules.

5.9.2 The OSC forwards the draft report to the TAG participants 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 participants 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 participants' 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 participants.

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. Others can similarly use this information for their own resource planning purposes.

5.9.5 The Collaborative Transmission Plan, and the associated models, serve as the basis for the models that the Transmission Providers provide as input to the development of the SERC-wide model as described in Section 10.

5.10 Status Reports

5.10.1 As part of the NCTPC Process, the Transmission Providers periodically provide the TAG participants 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 or TAG participant has the right to seek assistance from the North Carolina Utilities Commission (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.

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 South Carolina Public Service Commission 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. Any TAG participant, not just a TAG participant that is a Transmission Customer, may avail itself of the dispute resolution provision of the Tariff, as that process is modified below.

6.4.2 If a TAG participant has completed the negotiation step set forth in Section 12.1 of this Tariff, a TAG participant may ask to have the issue mediated on a non-binding basis before the next step (i.e., arbitration) commences. A request for mediation must be made within thirty days of the agreed-upon conclusion of the negotiation step. If the mediation step is concluded without resolution, the disputing party has thirty days to inform the Transmission Provider that it seeks to commence the arbitration step set forth in Section 12.2. If this mediation option is selected, the parties to the dispute will use the Commission's Dispute Resolution Service as the forum for mediation.

6.4.3 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

With the exception of "Regional Reliability Projects" and "RETPs," nothing in this Attachment is intended to alter the cost allocation policies of the 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 parties 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 *NCTPC Transmission Cost Allocation.*

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 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 As part of the RETP process, a network customer may ensure that power can be delivered from an interface on an RETP to network load. Such network transmission service would not be subject to the requestor pays approach. This transmission cost allocation would be in accordance with OATT provisions for network service.

7.3.4 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.

7.3.5 This RETP concept and cost allocation methodology applies to the NCTPC footprint, which consists of the Duke and Progress Control Areas. Pursuant to Order No. 890, other regions will adopt cost methodologies that apply to the costs of facilities located in their region.

7.4 SIRPP Cost Allocation

The cost allocation for Inter-Regional Economic Upgrade projects described in Appendix 1 will be determined in accordance with the cost allocation principles adopted by each Regional Planning Process in which each portion of the construction of such upgrades (in whole or in part) would occur. Thus, for the portion of an Inter-Regional Economic Upgrade project that is located in the NCTPC footprint, the cost allocation principles set forth in this Tariff and Section 7 would apply.

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 participants 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*.

8.1.5 Pursuant to Section 4, costs associated with economic studies that are outside the scope of the ETAP, will be borne by the study requestor.

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

8.1.7 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, which is one form of Confidential Information.

9.2 Identification of Confidential Information

The confidentiality of information is determined in the first instance by a NCTPC Participant or TAG participant providing the information. Examples of Confidential Information, other than CEII, include commercially sensitive information and customer-related information that is proprietary to a particular wholesale or retail customer. The NCTPC Participant or TAG participant providing Confidential Information acknowledges that such Confidential Information may be released to the representatives of TAG participants that have abided by the procedures in Section 9.4.3. If the information is Confidential Information only because it is CEII, the NCTPC Participant or TAG participant should indicate that such information may be released to TAG participants eligible to receive CEII.

9.3 Availability of Confidential Information

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

9.3.2 Confidential Information will be made available, to the extent not prohibited by law or government policy, 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 TAG participants may be provided Confidential Information, in accordance with Section 9.4.3/9.4.4. In cases where the information is Confidential Information only because it is CEII, the TAG participants may be provided such information in accordance with Section 9.4.4.

9.4 Obtaining Confidential Information

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 principles reflected in Order No. 890 as well as any Standards of Conduct or Code of Conduct requirements are being adhered to within the TAG process, to the extent applicable and/or necessary.

9.4.3 If a TAG participant seeks non-CEII Confidential Information, s/he must formally request the data from the ITP and demonstrate that s/he:

9.4.3.1 Is a representative of a TAG Sector Entity that has signed the SERC Confidentiality Agreement or is an Individual that has signed the SERC Confidentiality Agreement.

9.4.3.2 Is listed on Attachment A to a TAG Sector Entity's TAG Confidentiality Agreement as a representative of a TAG Sector Entity or is an Individual that has signed the TAG Confidentiality Agreement.

9.4.4 If a TAG participant seeks CEII, s/he must formally request the data from the ITP and demonstrate that s/he:

9.4.4.1 Is a representative of a TAG Sector Entity that has signed the SERC Confidentiality Agreement or is an Individual that has signed the SERC Confidentiality Agreement.

9.4.4.2 Is listed on Attachment A of a TAG Sector Entity's TAG Confidentiality Agreement as a representative of a TAG Sector Entity or is an Individual that has signed the TAG Confidentiality Agreement.

9.4.5 The NCTPC ITP will process the above requests, approve/deny the request, and if approved, provide the data to a TAG participant.

10. INTER-REGIONAL COORDINATION

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

10.1 Coordination Activities Within SERC

Duke and Progress are members of the SERC Reliability Corporation (SERC) and coordinate with other SERC members registered as Transmission Planners. SERC is the entity responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply systems in the area served by its member systems. SERC membership is open to any entity that is a user, owner, or operator of the Bulk-Power System and is subject to the jurisdiction of FERC for the purpose of complying with Reliability Standards. SERC membership is comprised of investor-owned, municipal, cooperative, state and federal systems, RTOs/ISOs, merchant electricity generators, and power marketers. SERC has in place various committees and subcommittees that perform the identified SERC functions, including the promotion of the reliability and adequacy of the bulk power system as related to the planning and engineering of the electric systems. The SERC committees are identified on SERC's website. The particular activities that are coordinated among the Transmission Planners include the creation of a SERC-wide model and the preparation of a simultaneous feasibility assessment, which are discussed in further detail below.

10.1.1 Regional Reliability Planning by Transmission Planners Located in SERC: A Transmission Planner's 10-year transmission expansion plan is the basis for models used for its own regional reliability planning process, such as the NCTPC, as well as serving as a Transmission Planner's input into the development of the SERC-wide model.

Substantive transmission planning occurs as Transmission Planners develop regional reliability transmission expansions plans through their regional planning process, such as the NCTPC. In this regard, the reliability plan for each region is generally developed by determining the required 10-year transmission expansion plan to satisfy load, resources, and transmission service commitments throughout the 10-year reliability planning horizon. The development of each regional reliability plan is facilitated through the creation of transmission models (base cases) that incorporate the current 10-year transmission expansion plan, load projections, resource assumptions (generation, demand response, and imports), and transmission service commitments within the region. The transmission models also incorporate external regional models (at a minimum the current SERC models) that are developed using similar assumptions.

The transmission models created for use in developing the regional reliability 10-year transmission expansion plan are analyzed to determine if any planning criteria concerns are projected. In the event one or more planning criteria concerns are identified at the regional level, the relevant Transmission Planners will develop solutions for these projected limitations in accordance with the regional process to which they belong. As a part of this study process, the Transmission Planners, in accordance with the regional process to which they belong, will reexamine the current regional reliability 10-year transmission expansion plan (determined through the previous year's regional reliability planning process) to determine if the current plan can be optimized based on the updated assumptions and any new planning criteria concerns identified in the analysis. The optimization process may include the deletion and/or modification of any of the existing reliability transmission enhancements identified in the previous year's reliability planning process.

10.1.2 Coordination by Transmission Planners with Affected Regions: Once a planning criteria concern is identified and the optimization process identifies the potential solution (at the regional level), the Transmission Planner(s), here Duke and Progress, determine if any transmission system in another region is potentially impacted by the projected solution. Potentially impacted regions are then contacted to determine if there is a need for an inter-regional *ad hoc* coordinated study. In the event one or more neighboring regions agrees that they would be impacted by the projected limitation or identifies the potential for a superior inter-regional reliability solution, based on transmission enhancements in their current regional reliability plan, an inter-regional *ad hoc* coordinated study is initiated. In the event that no inter-regional impacts are identified, or if once contacted the potentially impacted regions(s) determine that they will not actually be impacted, the initiating Transmission Planner will move forward to conduct a reliability study to determine the solution for the projected planning criteria concern. In either case, once the study has been completed, the identified reliability transmission enhancements will then be incorporated into the region's(s') 10-year transmission expansion plan as a reliability project.

10.1.3 SERC-Wide Reliability Assessment by Transmission Planners: After the transmission models are developed through the regional planning processes, the Transmission Planners within SERC create a SERC-wide transmission model and conduct a long-term reliability assessment. The intent of the SERC-wide reliability assessment is to determine if the different regional reliability transmission expansion plans are simultaneously feasible and to otherwise ensure that these regional processes are using consistent models and data. Additionally, the reliability assessment measures and reports the transfer capabilities between regions within SERC. The SERC-wide assessment serves as a valuable tool for each of the regions to reassess the need for additional inter-regional reliability joint studies.

10.1.4 Other Coordination Activities Within SERC

10.1.4.1 Transmission Model Development: SERC transmission models are developed by the Transmission Planners in SERC through an annual model development process. Each Transmission Planner in SERC, incorporating input from their regional planning process, develops and submits their 10-year transmission models to a model development databank. The databank then joins the models to create SERC-wide models for use in reliability assessment. Additionally, the SERC-wide models are then used in each regional planning process as an update (if needed) to the current transmission models and as a foundation (along with the MMWG models) for the development of next year's transmission models.

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

10.1.5 Stakeholder Participation in Planning and Coordination Activities:

Since the bulk of the reliability transmission planning occurs at the regional level as a "bottom up" process in the development of the various regions' 10-year transmission expansion plans, stakeholders in the NCTPC footprint may provide input into the coordination activities by participating in the NCTPC process and any other regional planning processes that they choose to participate in. Specifically, the 10-year transmission expansion plan developed in the NCTPC process described in this Attachment is the basis for Duke's and Progress' input into the SERC model development. As discussed in Sections 4 and 5, the TAG participants are provided a number of opportunities to review and comment on and allowed to propose alternatives concerning the development of this transmission expansion plan. The results of inter-regional coordination activities will be shared and discussed with TAG participants. If the results of coordination activities are to be shared at a TAG participant meeting, the meeting notice will indicate that such results will be shared and discussed and will either provide the results or indicate how the results can be obtained if the results include Confidential Information.

10.2 ERAG & SERC-RFC East Coordination 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 VACAR Coordination Activities

10.3.1 The Transmission Providers both participate with Fayetteville, NCEMC, North Carolina Municipal Power Agency #1, North Carolina Eastern Municipal Power Agency, South Carolina Electric & Gas Company, South Carolina Public Service Authority, Southeastern Power Administration, Dominion Virginia Power, and Alcoa Power Generating, Inc. in the VACAR Planning Task Force.

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

10.3.3 Duke and Progress 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 region, although VACAR coordinates with Southern and TVA under existing agreements.

10.4 Bilateral Coordination 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 studies on an as-needed basis.

10.5 Southeast Inter-Regional Participation Process Activities

Duke and Progress have joined with a group of southeast utilities to develop the Southeast Inter-Regional Participation Process. This process provides valid stakeholders the ability to request economic studies that would be evaluated on an inter-regional basis. The framework for this process is provided in a document entitled "Southeast Inter-Regional Participation Process" which is attached as Appendix 1. The purpose of the Southeast

Inter-Regional Participation Process is to facilitate the development of inter-regional economic planning studies.

10.5.1 Stakeholder Participation Through the SIRPP: As shown on the Southeast Inter-Regional Participation Process Diagram contained in Appendix 1, the particular activity that the SIRPP sponsors coordinate is the preparation of the inter-regional Economic Planning Studies addressed in Appendix 1. In addition, the SIRPP sponsors will review with stakeholders the data, assumptions, and assessment that are then being conducted on a SERC-wide basis at the following SIRPP meetings: the 1st Inter-Regional Stakeholder Meeting; the 2nd Inter-Regional Stakeholder Meeting; and the 3rd Inter-Regional Stakeholder Meeting.

10.6 Timelines and Milestones

The general timelines and milestones for the performance of both the reliability planning and coordination activities are provided in Appendix 2.

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 persons who may want to participate in state IRP and siting proceedings.

11.1 North Carolina

The 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 15-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 15-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.

12. LOCAL PLANNING

The Transmission Providers coordinate with their network and native load customers to ensure adequate and reliable electric service to all points of delivery within their control areas. The focus of the NCTPC is planning higher-voltage facilities and transfers of bulk power and thus "local planning" focuses on lower-voltage facilities and the delivery of energy to customer locations. Customer meetings may be held, when necessary, to discuss the respective plans of the customer and the provider and how such plans impact local areas. Any local area plans developed by a Transmission Provider are rolled into the power system models of the transmission providers and these models subsequently roll up to the NCTPC transmission models. The same data and assumptions would be used in local planning as are used in the NCTPC Process.

Appendix 1
Southeast Inter-Regional Participation Process

Introduction:
In an effort to more fully address the regional participation principle outlined in the Order 890 Attachment N Tariff requirements and the related guidance contained in the FERC Transmission Planning Process Staff White Paper (dated August 2, 2007), this Southeast Inter-Regional Participation Process expands upon the existing processes for regional planning in the Southeast. This document outlines an inter-regional process among various Southeastern interconnected transmission owners. The inter-regional process described herein is incorporated into each Participating Transmission Owner's[1] planning process and OATT Attachment N (for those transmission owners that have a regulatory requirement to file an Attachment N).

Purpose:
This inter-regional process complements the regional planning processes developed by the Participating Transmission Owners in the Southeast. For the purpose of this document, the term "Southeast Inter-Regional Participation Process" ("SIRPP") is defined as a new process to more fully address 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 Owner has established within its particular region for Attachment N purposes. Importantly, the Economic Planning Studies discussed herein are hypothetical studies that do not affect the transmission queue for purposes of System Impact Studies, Facilities Studies, or interconnection studies performed under other portions of the OATT.

Current Inter-Regional Planning Process:
Each Southeastern transmission owner 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 Owners collectively conduct inter-regional reliability transmission assessments, which include the sharing of the individual transmission system plans, providing information on the assumptions and data inputs used in the development of those plans and assessing whether the plans are simultaneously feasible.

Participating Transmission Owners:
Due to the additional regional planning coordination principles that have been announced in Order 890 and the associated Transmission Planning White Paper, several transmission owners have agreed to provide additional transmission planning coordination, as further described in this document. The "Participating Transmission Owners" are listed on the SIRPP website (http://www.southeastirpp.com).

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[1] The sponsors of the Southeast Inter-Regional Participation Process are referred to as transmission owners, rather than transmission providers, because not all of the sponsors are "Transmission Providers" for purposes of the *pro forma* OATT.

Southeast Inter-Regional Participation Process:
The Southeast 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 Owners' Attachment Ns 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 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 N processes may also serve as a mechanism to collect requests for inter-regional Economic Planning Studies by a participant's stakeholders group. The Economic Planning Studies requested through each participant's Attachment N process that involve impacts on multiple systems between Regional Planning Processes will be consolidated and evaluated as part of the Southeast Inter-Regional Participation Process. Stakeholders will also be provided the opportunity to submit their requests for inter-regional Economic Planning Studies directly to the Inter-Regional process.

The Participating Transmission Owners 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 Southeast Inter-Regional Participation Process (e.g. Southeastern Regional Planning Process coordinating with FRCC Regional Planning Process, Entergy coordinating with SPP, TVA coordinating with MISO and PJM, and the North Carolina Transmission Planning Collaborative coordinating with PJM). 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 Southeast Inter-Regional Participation Process.

With regard to the development of the stakeholder requested inter-regional Economic Planning Studies, the Participating Transmission Owners 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 Owners and the stakeholders.

With regard to coordinating with stakeholders in the development of the inter-regional Economic Planning Study(ies), in each cycle of the Southeast Inter-Regional Participation Process, the

Participating Transmission Owners will conduct three inter-regional stakeholder meetings. The information to be discussed at such meetings will be made available in final draft form for stakeholder review prior to any such meeting by posting on the SIRPP website and/or e-mails to SIRPP Stakeholder Group ("SIRPPSG") members. The Participating Transmission Owners will use reasonable efforts to make such information available at least 10 calendar days prior to the particular meeting. The Participating Transmission Owners will conduct the "1st Inter-Regional Stakeholder Meeting", as shown in the attached diagram. At this meeting, a review of all of the Economic Planning Study(ies) submitted through the participants' Regional Planning Processes or directly to the Inter-Regional process, along with any additional Economic Planning Study requests that are submitted at this 1st meeting, will be conducted. During this meeting, the stakeholders will select up to five studies that will be evaluated within the planning cycle. 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. 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 Owners 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 finalize its 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 Participating Transmission Owners and stakeholders.

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

Southeast Inter-Regional Participation Process Cycle:

The Southeast Inter-Regional Participation Process will be performed annually. Due to the expected scope of the requested studies and size of the geographical region encompassed, the Participating Transmission Owners will perform up to five (5) inter-regional Economic Planning Studies annually, which could encompass both Step 1 and Step 2 evaluations. A Step 1 evaluation will consist of a high level screen of the requested transfer and will be performed during a single year's planning cycle. The high level screen will identify transfer constraints and likely transmission enhancements to resolve the identified constraints. The Participating Transmission Owners will also provide approximate costs and timelines associated with the identified transmission enhancements to facilitate the stakeholders' determination of whether they have sufficient interest to pursue a Step 2 evaluation. Once a Step 1 evaluation has been completed for a particular transfer, the stakeholders have the option to request a Step 2 evaluation for that transfer to be performed during the subsequent year's Inter-Regional Participation Process Cycle. If the stakeholders opt to not pursue Step 2 evaluation for the requested transfer during the subsequent year's Inter-Regional Participation Process Cycle, an Economic Planning Study of that request may be re-evaluated in the future by being submitted for a new Step 1 evaluation. In the event that the stakeholders request a Step 2 evaluation, the Participating Transmission Owners will then perform additional analysis, which may include additional coordination with external processes. The Participating Transmission Owners will then develop detailed cost estimates and timelines associated with the final transmission enhancements. The Step 2 evaluation will ensure that sufficient coordination can occur with stakeholders and among the impacted Participating Transmission Owners. In addition, the Step 2 evaluation will provide sufficient time to ensure that the inter-regional study results are meaningful and meet the needs of the stakeholders.

It is important to note that the Participating Transmission Owners expect that a Step 2 evaluation will be completed prior to interested parties requesting to sponsor transmission enhancements identified in an Economic Planning Study. However, the Participating Transmission Owners will work with stakeholders if a situation develops where interested parties attempt to sponsor projects identified in a Step 1 evaluation and there is a compelling reason (e.g., where time is of the essence).

Inter-Regional Cost Allocation:
The cost allocation for Inter-Regional Economic Upgrade projects will be determined in accordance with the cost allocation principle adopted by each Participating Transmission Owner's Regional Planning Process in which each portion of the construction of such upgrades would occur. The cost allocation principle for each SIRPP Regional Planning Process is posted on the SIRPP website. Typically, since Inter-Regional Economic Upgrade projects will likely consist of improvements that will be physically located in the footprints of multiple Regional Planning Processes, this approach means the cost allocation for each part of the Inter-Regional Economic Upgrade project or each project within a set of projects will be governed by the cost allocation principle adopted by the Regional Planning Process in which that part of the project or set is physically located. For example, should an Inter-Regional Economic Upgrade project consist of a single, 100 mile 500 kV transmission line, with 30 miles physically located in Regional Planning Process "A" and the remaining 70 miles located in Regional Planning Process "B," then the cost allocation for the 30 miles of 500 kV transmission line located in Regional Planning Process "A" would be governed by that Regional Planning Process' cost allocation principle, and the cost allocation for the other 70 miles of 500 kV transmission line would be governed by the cost allocation principle of Regional Planning Process "B." Should an Inter-Regional Economic Upgrade project be physically located entirely within one Regional Transmission Planning process, the costs of the project would be governed by that region's cost allocation principle.

Inter-Regional Coordination of Economic Transmission Project Development:
Once an Economic Planning Study report has been finalized, multiple stakeholders may be interested in jointly participating in the project development. An Inter-Regional process addressing each such economic upgrade request will be developed that will formalize the process of determining if there is sufficient stakeholder interest to pursue economic project development and the coordination that will be required of the impacted Transmission Owners to support this process. The Participating Transmission Owners and the stakeholders will support this process development activity beginning in 2008.

Stakeholder Participation in the Southeast Inter-Regional Participation Process:

Purpose

The purpose of the Southeast SIRPPSG is to provide a structure to facilitate the stakeholders' participation in the Southeast Inter-Regional Participation Process. Importantly, the SIRPPSG shall have the flexibility to change the "Meeting Procedures" section discussed below but cannot change the Purpose, Responsibilities, Membership, or Data and Information Release Protocol sections absent an appropriate filing with (and order by) FERC to amend the OATT.

Responsibilities
In general, the SIRPPSG is responsible for working with the Participating Transmission Owners on Inter-Regional Economic Planning Study requests so as to facilitate the development of such studies that meet the goals of the stakeholders. The specific responsibilities of this group include:

1. Adherence to the intent of the FERC Standards of Conduct requirements in all discussions.
2. Develop the SIRPPSG annual work plan and activity schedule.
3. Propose and select the Economic Planning Study(ies) to be evaluated (five annually).
    a. Step 1 evaluations
    b. Step 2 evaluations
4. The SIRPPSG should consider clustering similar Economic Planning Study requests. In this regard, if two or more of the Economic Planning Study requests are similar in nature and the Participating Transmission Owners conclude that clustering of such requests and studies is appropriate, the Participating Transmission Owners may, following communications with the SIRPPSG, cluster those studies for purposes of the transmission evaluation.
5. Provide timely input on the annual Economic Planning Study(ies) scope elements, including the following:
    a. Study Assumptions, Criteria and Methodology
    b. Case Development and Technical Analysis
    c. Problem Identification, Assessment and Development of Solutions (including proposing alternative solutions for evaluation)
    d. Comparison and Selection of the Preferred Solution Options
    e. Economic Planning Study Results Report.
6. Providing advice and recommendations to the Participating Transmission Owners on the Southeast Inter-Regional Participation Process.

Membership
The SIRPPSG membership is open to any interested party.

Meeting Procedures
The SIRPPSG may change the Meeting Procedures criteria provided below pursuant to the voting structure in place for the SIRPPSG at that time. The currently effective Meeting Procedures for the SIRPPSG shall be provided to the Participating Transmission Owners to be posted on the SIRPP website and shall become effective once posted on that website (http://www.southeastirpp.com), which postings shall be made within a reasonable amount of time upon receipt by the Transmission Owners. Accordingly, the following provisions contained under this Meeting Procedures heading provide a starting-point structure for the SIRPPSG, which the SIRPPSG shall be allowed to change.

Meeting Chair
A stakeholder-elected member of the SIRPPSG will chair the SIRPPSG meetings and serve as a facilitator for the group by working to bring consensus within the group. In addition, the duties of the SIRPPSG chair will include:

1. Developing mechanisms to solicit and obtain the input of all interested stakeholders related to inter-regional Economic Planning Studies.
2. Ensuring that SIRPPSG meeting notes are taken and meeting highlights are posted on the SIRPP website (http://www.southeastirpp.com) for the information of the participants after all SIRPPSG meetings.

Meetings
Meetings of the SIRPPSG shall be open to all SIRPPSG members interested in inter-regional Economic Planning Studies across the respective service territories of the Participating Transmission Owners. There are no restrictions on the number of people attending SIRPPSG meetings from any interested party.

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

Voting
In attempting to resolve any issue, the goal is for the SIRPPSG to develop consensus solutions. However, in the event consensus cannot be reached, voting will be conducted with each SIRPPSG member's organization represented at the meeting (either physically present or participating via phone) receiving one vote. The SIRPPSG chair will provide notices to the SIRPPSG members in advance of the SIRPPSG meeting that specific votes will be taken during the SIRPPSG meeting. Only SIRPPSG members participating in the meeting will be allowed to participate in the voting (either physically present or participating via phone). No proxy votes will be allowed. During each SIRPP cycle, the SIRPPSG members will propose and select the inter-regional Economic Planning Studies that will be performed during that particular SIRPP cycle. The SIRPPSG will annually select up to five (5) inter-regional Economic Planning Studies, including both Step 1 evaluation(s) and any Step 2 evaluations, with any such Step 2 evaluations being performed for the previous years Step 1 studies for the pertinent transfers. Each organization represented by their SIRPPSG members will be able to cast a single vote for up to five Economic Planning Studies that their organization would like to be studied within the SIRPP cycle. If needed, repeat voting will be conducted until there are clear selections for the five Economic Planning Studies to be conducted.

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

Data and Information Release Protocol

SIRPPSG members can request data and information that would facilitate their ability to replicate the SIRPP inter-regional Economic Planning studies while ensuring that CEII and other confidential data is protected.

CEII Data and Information

SIRPPSG members may be certified to obtain CEII data used in the SIRPP by following the confidentiality procedures posted on the SIRPP website (e.g., making a formal request for CEII, authorizing background checks, executing the SIRPP CEII Confidentiality Agreement, etc.). The SIRPP Participating Transmission Owners reserve the discretionary right to waive the certification process, in whole or in part, for anyone that the SIRPP Participating Transmission Owners deem appropriate to receive CEII. The SIRPP Participating Transmission Owners also reserve the discretionary right to reject a request for CEII; upon such rejection, the requestor may pursue the SIRPP dispute resolution procedures set forth below.

Non-CEII Confidential Information

The Participating Transmission Owners will make reasonable efforts to preserve the confidentiality of information that is confidential but not CEII in accordance with the provisions of the Tariff and the requirements of (and/or agreements with), NERC and/or SERC as well as agreements with the other Participating Transmission Owners and any other contractual or legal confidentiality requirements.

Without limiting the applicability of the foregoing, to the extent confidential non-CEII information is provided in the transmission planning process and is needed to participate in the transmission planning process and/or to replicate transmission planning studies, it will be made available to those SIRPPSG members who have executed the SIRPP Non-CEII Confidentiality Agreement, which is posted on the SIRPP website. Importantly, if information should prove to contain both confidential and non-CEII information and CEII, then the requirements of both this section and the previous section would apply.

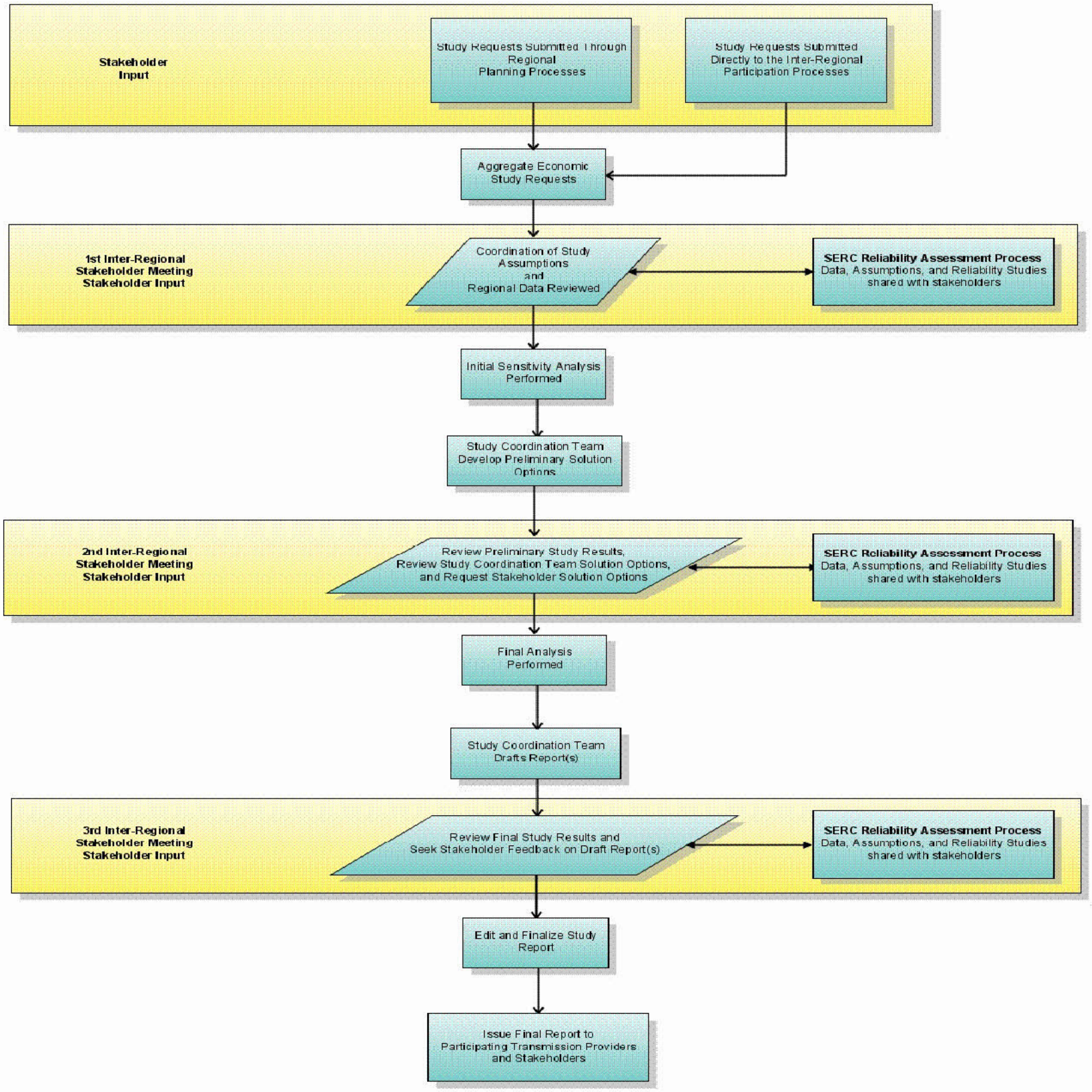
Dispute Resolution

Any procedural or substantive dispute between a stakeholder and a Participating Transmission Owner that arises from the SIRPP will be addressed by the Participating Transmission Owner's dispute resolution procedures in its respective Regional Planning Process. In addition, should the dispute only be between stakeholders with no Participating Transmission Owner involved (other than its ownership and/or control of the underlying facilities), the stakeholders will be encouraged to utilize the Commission's alternative means of dispute resolution.

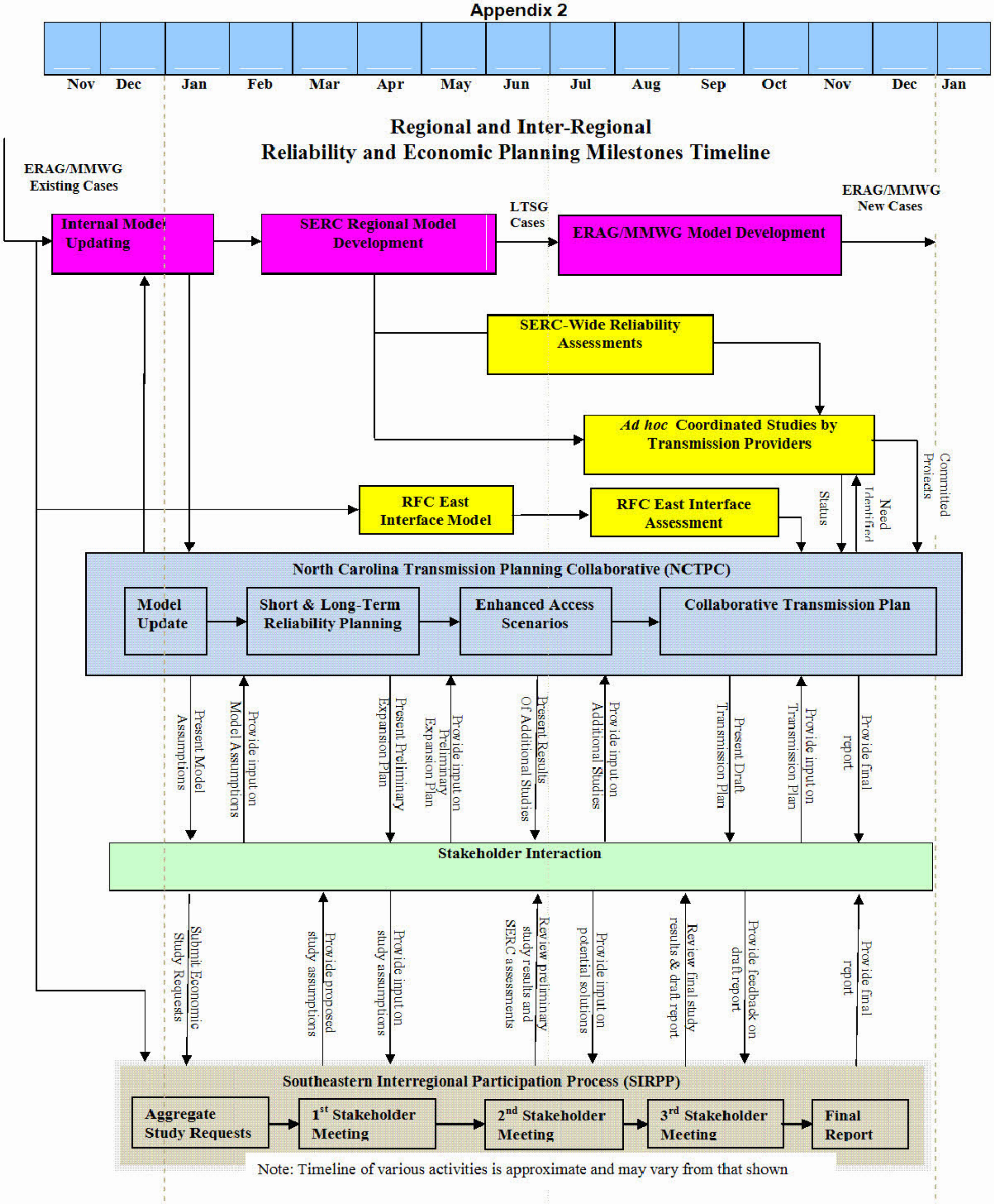
Should dispute resolution proceedings be commenced in multiple Regional Planning Processes involving a single dispute among multiple Participating Transmission Owners, the affected Participating Transmission Owners, in consultation with the affected stakeholders, agree to use reasonable efforts to consolidate the resolution of the dispute such that it will be resolved by the dispute resolution procedures of a single Regional Planning Process in a single proceeding. If such a consensus is reached, the Participating Transmission Owners agree that the dispute will be addressed by the dispute resolution procedures of the selected Regional Transmission Planning Process.

Nothing herein shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

Southeast Inter-Regional Participation Process Diagram:



Appendix 2


Nov
Dec
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Jan
Regional and Inter-Regional
Reliability and Economic Planning Milestones Timeline
ERAG/MMWG Existing Cases
Internal Model Updating
SERC Regional Model Development
LTSG Cases
ERAG/MMWG Model Development
ERAG/MMWG New Cases
SERC-Wide Reliability Assessments
Ad hoc Coordinated Studies by Transmission Providers
Committed Projects
RFC East Interface Model
RFC East Interface Assessment
Status
Need Identified
North Carolina Transmission Planning Collaborative (NCTPC)
Model Update
Short & Long-Term Reliability Planning
Enhanced Access Scenarios
Collaborative Transmission Plan
Present Model Assumptions
Provide input on Model Assumptions
Present Preliminary Expansion Plan
Provide input on Preliminary Expansion Plan
Present Results Of Additional Studies
Provide input on Additional Studies
Present Draft Transmission Plan
Provide input on Transmission Plan
Provide final report
Stakeholder Interaction
Submit Economic Study Requests
Provide proposed study assumptions
Provide input on study assumptions
Review preliminary study results and SERC assessments
Provide input on potential solutions
Review final study results & draft report
Provide feedback on draft report
Provide final report
Southeastern Interregional Participation Process (SIRPP)
Aggregate Study Requests
1st Stakeholder Meeting
2nd Stakeholder Meeting
3rd Stakeholder Meeting
Final Report
Note: Timeline of various activities is approximate and may vary from that shown

Appendix 3

Sector Voting Example

The example below illustrates the TAG Sector Voting Process. For purposes of explaining the example, we assume that the General Public (GP) Sector has 10 Individuals present. In addition to the 10 Individuals, there are 17 other TAG Sector Entities present, spread across four TAG Sectors (Cooperative LSEs (Coop LSE); Municipal LSEs (Muni LSE); Investor-Owned LSEs (IOU LSE); and Transmission Customers (TC)). These 17 TAG Sector Entities may each have several TAG participants present but only one may vote in one sector. Each Individual and TAG Sector Entity casts their vote, which vote is then weighted based on the number of persons/entities voting in the TAG Sector of which they are a member. E.g., since there are six Coop LSEs is present, each Coop LSE's vote is worth 1.00/6 or .166 (*see* Columns 4 and 5 for weighted vote). As the final step, the votes are weighted again, based on the number of TAG Sectors present. With five TAG Sectors present, each Sector Yes Vote and Sector No Vote is multiplied by 1.00/5 = .20. The weighted total is reported in columns 6 and 7. In the example, the No votes have won .53 to .47.

Column	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Sector	**No. of Voters**	**Yes Votes**	**No Votes**	**Sector Yes Vote**	**Sector No Vote**	**Weighted Sector Yes**	**Weighted Sector No Vote**
Coop LSE	6	6	0	1.00	0	.20	0
Muni LSE	8	2	6	.25	.75	.05	.15
IOU LSE	2	1	1	.50	.50	.10	.10
TP/TO	0	0	0	0	0	0	0
TCs	1	0	1	0	1.00	0	.20
GICs	0	0	0	0	0	0	0
ECs	0	0	0	0f	0	0	0
GP	10	6	4	.60	.40	.12	.08
Total Vote						0.47	0.53

ATTACHMENT ~~K~~N-2

Transmission Planning Process
(FPC Zone)

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

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

The Florida Public Service Commission ("FPSC") is an integral part of the planning process by providing input, guidance, regulatory oversight and decision-making under this process. Additionally, the FPSC conducts workshops on an annual basis to review the transmission and generation expansion plans for Florida. The FPSC, under Florida law, has the authority to ensure an adequate and reliable electric system for Florida.

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1 The FRCC provides a page on its website where all of the FRCC documents referenced in this Attachment ~~K~~N-2 are listed along with their URL addresses. The URL address for this FRCC webpage is: https://www.frcc.com/Planning/Shared%20Documents/FRCC_Reference_Documents.pdf. This provides flexibility for the FRCC to change the URL addresses for these individual FRCC documents without requiring the modification of tariff language.

As set forth below, Transmission Provider's Transmission Planning Process is a seamless process that fully integrates both the local and regional transmission planning and is designed to satisfy the following principles, as defined in the FERC Final Rule in Docket No. RM05-25-000: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects. Descriptions of the *FRCC Regional Transmission Planning Process* are contained herein as they relate to Transmission Provider's Transmission Planning Process.

Section I. Coordination

1.1 Transmission Provider consults and interacts directly with its customers in providing transmission service and generator interconnection service as well as with its neighboring transmission providers, on a regular basis. A transmission customer may request and/or schedule a meeting with Transmission Provider to discuss any issue related to the provision of transmission service at any time. Transmission Provider consults and interacts with its customers any time during the study process that either the transmission customer or the Transmission Provider deem necessary and/or at various stages of the planning process (e.g., Scoping Meeting, Feasibility, System Impact and Facilities Studies). An open dialogue between the transmission customer and the Transmission Provider takes place regarding customer needs. This interaction and dialogue between the customer and Transmission Provider are further described under the Local Transmission Network Planning Process as set forth in Appendix 1 to this Attachment ~~K~~N-2. Topics such as load growth projections, planned generation resource additions/deletions, new delivery points and possible transmission alternatives are discussed. This dialogue is intended to provide timely and meaningful input and participation of customers during the early stages of development of the transmission plan. Additionally, the transmission customer shall have an opportunity to comment at any time during the evaluation process and/or when study findings (Feasibility, System Impact and Facilities Studies) are communicated by the Transmission Provider to the customer. Transmission Provider communicates with its neighboring transmission providers on a regular basis, and Transmission Provider facilitates communication and consultation between its customers and its neighboring transmission service providers/owners, specifically, if during the transmission service study process, a neighboring system's facilities are identified as being affected. This coordination process continues in a seamless manner at the local as well as the regional level, leading to each Transmission Provider providing an initial transmission plan which, when consolidated, becomes the initial regional transmission plan. The initial transmission plan submitted to the FRCC by the Transmission Provider, which results from the Local Transmission Network Planning Process as set forth in Appendix 1 to this Attachment ~~K~~N-2, will be posted by the FRCC in accordance with the *FRCC Regional Transmission Planning Process* (reference link to *Initial Plans* on the FRCC website). This initial transmission plan is reviewed by the FRCC as well as all interested transmission customers/users. The Transmission Provider relies on the FRCC Committee process to finalize its initial transmission plan as submitted to the FRCC. In addition to transmission customers/users being provided timely and meaningful input and participation during the planning process with the Transmission Provider, the transmission customers/users are also given an additional opportunity to raise any issues, concerns or minority opinions that they believe have not been adequately addressed by any Transmission Providers' initial transmission plan submittal during the FRCC review process. This FRCC review process normally commences shortly after the submittal of the Ten Year Site Plans to the FPSC on April 1 of each year. Once issues raised by interested stakeholders are addressed, the Planning Committee approves the proposed regional transmission plan and presents it to the FRCC Board for approval. Upon approval by the Board, which is expected in December of each year, the FRCC sends the final regional transmission plan to the FPSC. Unresolved issues may be referred to the FRCC Dispute Resolution Process as described below.

1.2 The *FRCC Regional Transmission Planning Process* is intended to ensure the long-term reliability and economic needs of the bulk power system in the FRCC Region.[2] An objective of the *FRCC Regional Transmission Planning Process* is to ensure coordination of the transmission planning activities within the FRCC Region in order to provide for the development of a reliable and economically robust transmission network in the FRCC Region. The process is intended to develop a regional transmission plan to meet the existing and future requirements of all customers/users, providers, owners, and operators of the transmission system in a coordinated, open and transparent manner.

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

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

FRCC meeting notices, meeting minutes and documents of FRCC Planning Committee and/or FRCC Board meetings in which transmission plans or

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

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

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

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

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

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

Section 2 Openness

2.1 Transmission Provider provides notice and schedules meetings with its transmission customers as deemed necessary by the transmission customer and/or Transmission Provider. Transmission Provider schedules meetings with its customers to interact, exchange perspectives or share findings from studies. Transmission Provider communicates and interacts with its transmission service customers on a regular basis to discuss loads, generation/network resource additions/deletions, new facility additions and upgrades, demand resource information, customer's projections of future needs, and related subjects that have an impact on the provision of transmission service to a customer. Transmission Provider provides a status update to its customers on a regular basis or at any time, if requested by a customer. Additionally, Appendix 1 to this Attachment ~~K~~N-2 describes the customer and Transmission Provider interaction in the flow diagram and outlines the steps of the Local Transmission Network Planning Process.

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

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

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

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

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

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

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

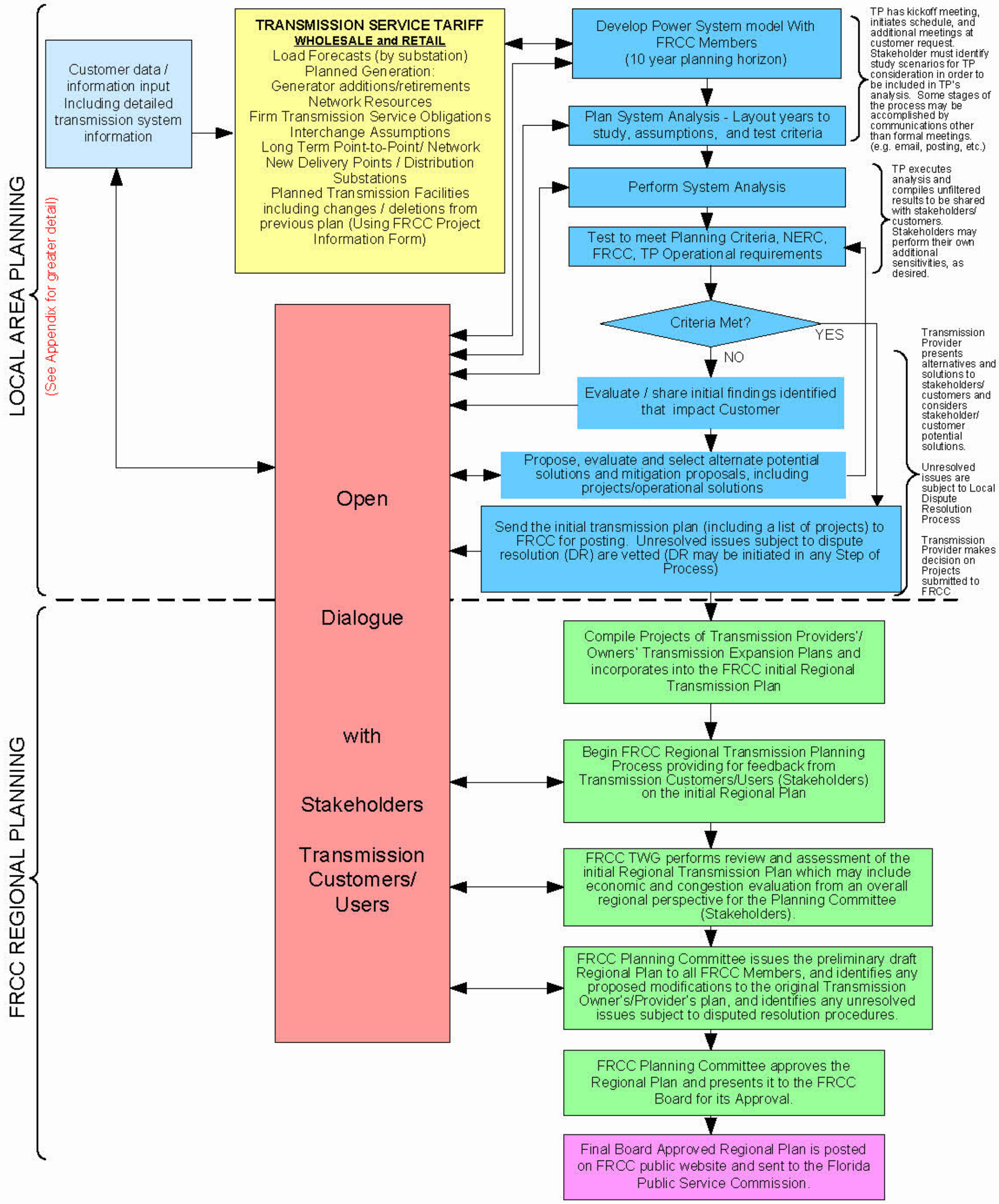
Section 3 Transparency

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

3.2 During the Transmission Provider's local area planning process the Transmission Provider utilizes the FRCC databanks which contain information provided by the Transmission Provider and customers of projected loads as well as all planned and committed transmission and generation projects, including upgrades, new facilities and changes to planned-in-service dates over the planning horizon, as the base case for Transmission Provider's studies. Transmission Provider makes available to a transmission service customer the underlying data, assumptions, criteria and underlying transmission plans utilized in the study process. Transmission Provider provides written descriptions of the basic methodology, criteria and processes used to develop plans. In order to get a better understanding, a transmission customer may inquire about the assumptions, data and/or underlying methods, criteria, etc. and the customer will be provided a response by the Transmission Provider's qualified technical representative. Dialogue during the study process is encouraged. The dialogue during the Transmission Providers local area planning process between the Transmission Provider and customers involves discussions of the initial findings that affect customers, potential alternatives including feasibility of mitigating any adverse findings, and third party impacts. Discussion of initial findings in areas of the system that affect customers is intended to communicate and validate with the customer issues or concerns identified by the Transmission Provider or conversely, issues not specifically identified by the Transmission Provider that may be of concern to the customers. As part of the process of identifying potential alternatives to mitigate any adverse issue or concern, the dialogue with the customer should facilitate the identification of the most effective solution. This dialogue during the different stages of the planning process provides for meaningful input and participation of transmission customers in the development of the transmission plan. The goal of this interaction between the Transmission Provider and customers is to develop a transmission expansion plan that meets the needs of the Transmission Provider and customer in a reliable cost effective manner. This planning process between the Transmission Provider and customers is described in the process flow diagram below and in the more detailed description of the Local Transmission Network Planning Process as set forth in Appendix 1 to this Attachment ~~K~~N-2.

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

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



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

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

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

- The *Regional Load and Resource Plan* contains aggregate data on demand and energy, capacity and reserves, and proposed new generating unit and transmission line additions for Peninsular Florida as well as statewide.
- The *Reliability Assessment* is an aggregate study of generating unit availability, forced outage rates, load forecast methodologies, and gas pipeline availability.
- The *Long Range Transmission Reliability Study* is an assessment of the adequacy of Peninsular Florida's bulk power and transmission system. The study includes both short-term (1-5 years) detailed analysis and long-term (6-10 years) evaluation of developing trends that would require transmission additions or

other corrective action. Updates on regional areas of interest and/or constraints (e.g., Central Florida) are also addressed.

Section 4 Information Exchange

4.1 Transmission Provider participates in information exchange on a regular and ongoing basis with the FRCC, neighboring utilities, and customers. Transmission customers are required to submit data for the planning process described in this Attachment ~~K~~N-2 to the Transmission Provider in order for the Transmission Provider to plan for the needs of network and point-to-point customers. This data/information shall be provided by the transmission customer by no later than January 1 of each year. Such data/information includes load growth projections, planned generation resource additions/upgrades (including network resources), any demand response resources, new delivery points, new or continuation of long-term firm point-to-point transactions with specific receipt (i.e., source or electrical location of generation resources) and delivery points, (i.e., the electrical location of load or sink where the power will be delivered to), and planned transmission facilities. This data/information shall be provided over the 10 year planning horizon to the extent such information is known. Additionally, the transmission customer shall provide timely written notice of any material changes to this data/information as soon as practicable due to the possible effect on the transmission plan or the ability of the Transmission Provider to provide service.

4.2 The Transmission Provider utilizes the information provided in modeling and assessing the performance of its system in order to develop a transmission plan that meets the needs of all customers of the transmission system. The Transmission Provider exchanges information with a transmission customer to provide an opportunity for the transmission customer to evaluate the initial study findings or to propose potential alternative transmission solutions for consideration by the Transmission Provider. If the Transmission Provider and transmission customer agree that the transmission customer's recommended solution is the best over-all transmission solution then such solution will be incorporated in the Transmission Provider's plan. Through this information exchange process the transmission customer has an integral role in the development of the transmission plan. This process is described in greater detail in Appendix 1 to this Attachment ~~K~~N-2. Consistent with the Transmission Provider's obligation under federal and state law, and under NERC and FRCC reliability standards, the Transmission Provider is ultimately responsible for the transmission plan.

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

For power flow models:

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

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

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

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

- Zero and negative sequence impedances;

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

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

Section 5 Comparability

5.1 This comparability principle is applied in all aspects of the transmission planning process including each of the respective principles in this Attachment ~~K~~N-2. Transmission Provider incorporates into its transmission plans on a comparable basis all firm transmission obligations, both retail and wholesale. The retail obligations consist of load growth, interconnection and integration of new network resources, firm power purchases and new distribution substations. Transmission Provider wholesale obligations are existing firm wholesale power sales, existing long-term firm transmission service including firm point-to-point and network (interconnection and integration of network resources), projected network load, generator interconnections, and new delivery points.

5.2 Transmission Provider plans for forecasted load, generation additions/upgrades which include network resources and new distribution substations associated with retail service obligations. A network transmission customer provides corresponding data as part of the provision of service, such as load forecast data, generation additions/upgrades including network resource forecast, new delivery points, and other information needed by the Transmission Provider to plan for the needs of the customer. Both Transmission Provider and the transmission customers reflect their demand response resources within the information that is input within this planning process. The data required for planning the transmission system for both retail and wholesale customers is comparable. Transmission customers/users (retail and wholesale) accurately reflect their demand response resources appropriately in their load forecast projections. To the extent a customer/stakeholder has a demand response resource or a generation resource that is not incorporated into its submitted plans and such customer/stakeholder desires the Transmission Provider to specifically consider on a comparable basis such demand response resource or generation resource as an alternative to transmission expansion, or in conjunction with the Transmission Provider's transmission expansion plan, such customer/stakeholder sponsoring such demand response resource or generation resource shall provide the necessary information (cost, performance, lead time to install, etc.) in order for the Transmission Provider to consider such demand response resource or generation resource alternatives comparably with other alternatives. Any customer/stakeholder sponsoring a demand response resource or generation alternative should participate in the planning process. The Transmission Provider shall treat customer/stakeholder resources and its own resources on a comparable basis for transmission planning purposes. This comparability principle is also further described under the Local Transmission Planning Process as set forth in Appendix 1 to this Attachment ~~K~~N-2. The data/information is also provided to the FRCC for their use in databank development and analysis under the *FRCC Regional Transmission Planning Process*. These data requirements are generally communicated by OASIS, email, letter or combination thereof.

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

Section 6 Dispute Resolution

6.1 If a dispute arises between a transmission customer and the Transmission Provider under the local transmission planning process set forth in Appendix 1 to this Attachment ~~K~~N-2 or involving Transmission Service under the Tariff, the senior representatives of the Transmission Provider and the customer shall attempt to resolve the dispute and may mutually agree to utilize a mediation service for that purpose. However, if such dispute is not resolved, then the Dispute Resolution Procedures set forth in Article 12 of the Tariff shall govern. If a dispute arises among or between Transmission Provider and another transmission owner(s) involving a cost allocation issue regarding the Cost Allocation Methodology and Principles, then the dispute resolution process set forth below under the cost allocation principle of this Attachment ~~K~~N-2 shall govern. If a dispute arises among or between Transmission Provider and another transmission provider/owner(s), regarding the *FRCC Regional Transmission Planning Process*, then the dispute resolution procedures that are contained in the *FRCC Regional Transmission Planning Process* as set forth below in this Attachment ~~K~~N-2 shall govern.

6.2 The *FRCC Regional Transmission Planning Process* has two alternative dispute resolution processes. Any party raising an unresolved issue may request the Mediator Dispute Resolution Process, which involves a mediator being selected jointly by the disputing parties. If the Mediator Dispute Resolution Process is completed, and the issue is still unresolved, by mutual agreement between the parties, the Independent Evaluator Dispute Resolution Process may be utilized. The Independent Evaluator is selected by the FRCC Board of Directors. If the issue is unresolved by either of the dispute resolution processes, the transmission owners, affected parties, or the FRCC may request that the FPSC address such unresolved dispute. Notwithstanding the foregoing, any unresolved issue(s) may be submitted to any regulatory or judicial body having jurisdiction.

Described below are the two alternative dispute resolution processes:

6.2.1 Alternative 1 - Mediator Dispute Resolution Process (Non-Binding) The Mediator Process shall be completed within 60 days of commencement. A mediator shall be selected jointly by the disputing parties. The mediator shall: (1) be knowledgeable in the subject matter of the dispute, and (2) have no official, financial, or personal conflict of interest with respect to the issues in controversy, unless the interest is fully disclosed in writing to all participants and all participants waive in writing any objection to the interest. The disputing parties shall attempt in good faith to resolve the dispute in accordance with the procedures and timetable established by the mediator. In furtherance of the mediation efforts, the mediator may:

- Require the parties to meet for face-to-face discussions, with or without the mediator;
- Act as an intermediary between the disputing parties;
- Require the disputing parties to submit written statements of issues and positions; and
- If requested by the disputing parties, provide a written recommendation on resolution of the dispute.

If a resolution of the dispute is not reached by the 30th day after the appointment of the mediator or such later date as may be agreed to by the parties, the mediator shall promptly provide the disputing parties with a written, confidential, non-binding recommendation on resolution of the dispute, including the mediator's assessment of the merits of the principal positions being advanced by each of the disputing parties. At a time and place specified by the mediator after delivery of the foregoing recommendation, but no later than 15 days after issuance of the mediator's recommendation, the disputing parties shall meet in a good faith attempt to resolve the dispute in light of the mediator's recommendation. Each disputing party shall be represented at the meeting by a person with authority to settle the dispute, along with such other persons as each disputing party shall deem appropriate. If the disputing parties are unable to resolve the dispute at or in connection with this meeting, then: (1) any disputing party may commence such arbitral, judicial, regulatory or other proceedings as may be appropriate; and (2) the recommendation of the mediator shall have no further force or effect, and shall not be admissible for any purpose, in any subsequent arbitral, administrative, judicial, or other proceeding.

The costs of the time, expenses, and other charges of the mediator and of the mediation process shall be borne by the parties to the dispute, with each side in a mediated matter bearing one-half of such costs. Each party shall bear its own costs and attorney's fees incurred in connection with any mediation.

6.2.2 Alternative 2 - Independent Evaluator Dispute Resolution Process (Non-Binding).

The Independent Evaluator Dispute Resolution Process shall be completed within 90 days.

An assessment of the unresolved issue(s) shall be performed by an Independent Evaluator that will be selected by the FRCC Board. The Independent Evaluator shall evaluate the disputed issue(s) utilizing the same criteria that the Planning Committee is held to, that is, "the applicable reliability criteria of FRCC and NERC, and the individual transmission owner's/provider's specific design, operating and planning criteria."

The Independent Evaluator shall be a recognized independent expert with substantial experience in the field of transmission planning with no past business relationship to any of the affected parties within the past two years from the date the Dispute Resolution Process is started.

The Board shall retain an Independent Evaluator within 15 days of the request to utilize the Independent Evaluator Dispute Resolution Process.

The Independent Evaluator shall prepare a report of its findings, with recommendations on the unresolved issue(s), to the Board and the Planning Committee within 45 days from the date the Board selected the Independent Evaluator. The Independent Evaluator's findings and recommendations shall not be binding. The Board, with the assistance of the Planning Committee and the Independent Evaluator's report, shall attempt to resolve the unresolved issue(s) within 30 days from receipt of the Independent Evaluator's report. If the Board fails to resolve the issue(s) to the satisfaction of all parties, any disputing party may commence such arbitral, judicial, regulatory or other proceedings as may be appropriate.

The costs of the Independent Evaluator shall be borne by the parties to the dispute with each party bearing an equal share of such costs. The FRCC shall be one of the parties. Each party shall bear its own costs and attorney fees incurred in connection with the dispute resolution.

Section 7 Regional Participation

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

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

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

7.4 Southern, PowerSouth Energy Cooperative (formally known as Alabama Electric Cooperative), Dalton Utilities, Georgia Transmission, MEAG Power, and South Mississippi Electric Power Association also sponsor the Southeastern Regional

Transmission Planning ("SERTP") forum. These SERTP sponsors are located within the Southeastern Subregion of SERC. The FRCC and the SERTP have established their respective links to transmission providers and FRCC/SERTP websites as applicable that contain study methodologies, joint transmission studies, inter-regional transmission service and generator interconnection service related studies, and the FRCC/SERTP process for requesting inter-regional economic studies. The FRCC website link that contains this type of information can be found under the *Florida-SERC Inter-Regional Transmission Information* folder. In this folder please refer to a document entitled *FRCC Inter-regional Coordination Process* that describes how information, modeling data and expansion plans are shared. The SERTP website link is http://www.southeasternrtp.com. Transmission providers within the FRCC and SERTP coordinate with each other as necessary in the performance of economic studies. The *FRCC SE Region Economic Study Request* document posted under the *Florida-SERC Inter- Regional Transmission Information* folder on the FRCC website describes the process and procedures for requesting inter-regional economic studies. FRCC and SERTP transmission providers plan to attend transmission planning forums when study findings are presented to stakeholders that impact their respective transmission systems.

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

Section 8 Economic Planning Studies

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

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

Section 9 Cost Allocation

[9.1 – 9.3 refers to third party impacts resulting from the FRCC Regional Planning Process; 9.4 refers to economic transmission improvements. The Cost Allocation provisions contained in the Section relate to cost allocation procedures for specific circumstances as described herein. All other transmission cost allocation not specifically described below is provided in accordance with OATT provisions for generation interconnection, network and point-to-point service.]

9.1 If a transmission expansion is identified as needed under the FRCC Regional Transmission Planning Process and such transmission expansion results in a material adverse system impact upon a third party transmission owner, the third party transmission owner may choose to utilize the FRCC Principles for Sharing of Certain Transmission Expansion Costs as outlined below in this Attachment ~~K~~N-2. The FPSC is involved in this process and provides oversight, guidance and may exercise its statutory authority as appropriate. A more detailed description of the FRCC Principles for Sharing of Certain Transmission Expansion Costs can be found on the FRCC website.

9.2 The FRCC Principles for Sharing of Certain Transmission Expansion Costs: (i) sets forth certain principles regarding the provision of financial funding to Transmission Owners[3] that undertake remedial upgrades to, or expansions of, their systems resulting from upgrades, expansions, or provisions of services on the systems of *other* Transmission Owners, and (ii) procedures for attempting to resolve disputes among Transmission Owners and other parties regarding the application of such principles. These principles shall not apply to transmission upgrades or expansions if, and to the extent that, the costs thereof are subject to recovery by a Transmission Owner pursuant to FERC Order 2003 or Order 2006.

9.3 Principles

9.3.1 Each Transmission Owner in the FRCC Region shall be responsible for upgrading or expanding its transmission system in accordance with the FRCC Regional Transmission Planning Process consistent with applicable NERC and FRCC Reliability Standards and shall participate, directly or indirectly (as the member of a participating Transmission Owner, e.g., Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency), in the FRCC Regional Transmission Planning Process in planning all upgrades and expansions to its system.

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

[3] For this purpose, "Transmission Owner" means an electric utility owning transmission facilities in the FRCC Region.

service on another Transmission Owner's system that may result in the need for a Remedial Upgrade on the Affected Transmission Owner's system for which Financial Assistance is to be provided hereunder include the following Precipitating Events:

- A new generating unit(s) to serve incremental load
- A new or increased long-term sale(s)/purchase(s) to or by others (different uses)
- A new or modified long-term designation of Network Resource(s)
- A new or increased long-term, firm reservation for point-to-point transmission service Specific non-Precipitating Events are as follows: 1) Transmission requests that have already been confirmed prior to adoption of these principles; 2) Qualifying rollover agreements that are subsequently rolled over; 3) Redirected transmission service for sources to the extent the redirected service does not meet the Threshold Criteria described in paragraph 9.3.5.1. Existing flows would not be considered "incremental."; and 4) Repowered generation if the MW output of the facility is not increased, regardless of whether the repowered unit is used more/less hours of the year.

9.3.3 Except to the extent that an Affected Transmission Owner is entitled to Financial Assistance from other parties as provided herein, each Transmission Owner shall be responsible for all costs of upgrades to, and expansions of, its transmission system; provided, however, that nothing herein is intended to affect the right of any Transmission Owner or another party from obtaining remuneration from other parties to the extent allowed by contract or otherwise pursuant to applicable law or regulation (including, for example, through rates to a Transmission Owner's customers).

9.3.4 Each Transmission Owner shall be solely responsible for the execution, or acquisition, of all engineering, permitting, rights-of-way, materials, and equipment, and for the construction of facilities comprising upgrades or expansions, including Remedial Upgrades, of its transmission system; provided, however, that nothing herein is intended to preclude a Transmission Owner from seeking to require another party to undertake some or all of such responsibilities to the extent allowed by contract or otherwise pursuant to applicable law.

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

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

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

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

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

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

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

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

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

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

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

- Transmission facilities in a zone are substantially electrically independent of other zones.
- Zones represent electrical demarcation areas in the FRCC transmission grid that can be supported from a technical perspective.

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

9.3.8 Implementation and Dispute Resolution Process:

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

9.3.8.2 In the event the parties identified in the foregoing paragraph are unable to reach agreement on the determination or assignment of cost responsibility within a sixty (60) day period, the dispute shall be referred to the parties' designated senior representatives, who have been previously identified, for resolution as promptly as practicable and written notice shall be provided to the Florida Public Service Commission.

9.3.8.3 In the event the senior designated representatives are unable to resolve the dispute within sixty (60) days by mutual agreement, such dispute may be submitted to any bodies having jurisdiction over the matter.

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

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

9.4 **Costs of** economic transmission facility improvements that are specifically related to economic projects that were evaluated in the economic planning study process (versus transmission facility improvements undertaken, for example, pursuant to a transmission service request or to resolve reliability issues) will be subject to the following cost allocation methodology. The costs of the economic transmission projects will be allocated proportionally to the project participant(s) (based on the MW requested by a participant(s)) which elect to proceed with the installation of such transmission improvements. The project participant(s) which commit to the transmission improvements will receive firm transmission service. The project participant(s) which take firm transmission service will be entitled to a monthly credit against its transmission service bill. If after twenty years of taking transmission service the project participant(s) has not fully offset the initial investment with transmission service credits, such participant(s) shall receive the balance of the outstanding credits for the initial transmission investment. The Transmission Provider may seek approval from appropriate state and federal regulatory bodies to incorporate, at the appropriate times, the credits that are provided to the project participant(s) in taking transmission service into retail and wholesale rates respectively.

Section 10 Recovery of Planning Costs

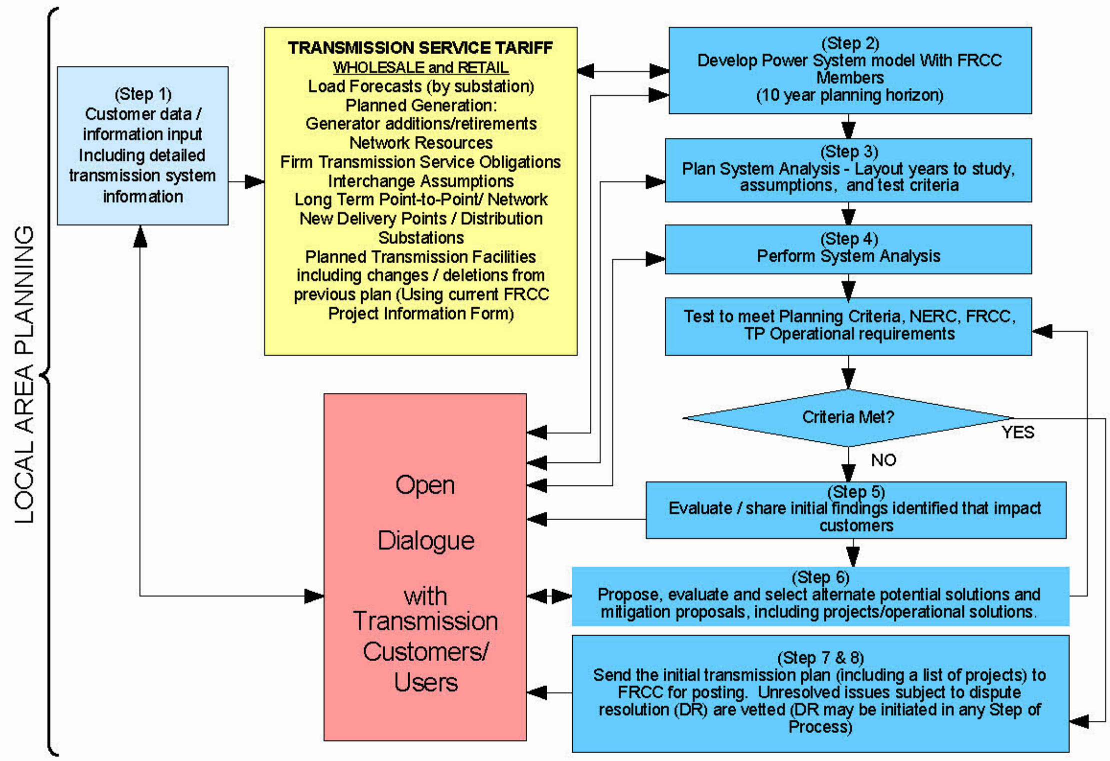
10.1 Planning study costs incurred by the Transmission Provider in the performance of studies requested by a customer/stakeholder associated with transmission service or generator interconnection service are separately addressed in this tariff under provisions that require the customer/stakeholder to pay the cost of such studies. Planning study costs incurred by the Transmission Provider in the performance of the first five economic planning studies will be absorbed by the Transmission Provider in its normal course of business of performing its obligations under this Attachment ~~K~~N-2. The cost of the sixth and additional economic planning studies in a calendar year will be assessed to the requesting entity as set forth in Section 8.1. Other general transmission planning costs not associated with the above studies are routine cost-of-service items that would be reflected in both wholesale and retail transmission rates as appropriate.

Appendix 1 to Attachment ~~K~~N-2

Local Transmission Network Planning Process – Process Description

The Local Transmission Network Planning Process ("Local Process") is performed annually with the Transmission Provider's plan being finalized on or about April 1st of each calendar year. The times shown (in months) for each of the steps contained in the Local Process are target dates that recognize some potential overlapping of the various activities. The Transmission Provider may develop a different timeline where warranted with the concurrence of the Transmission Provider's Customers/Stakeholders. The timelines and dates in this Appendix 1 to Attachment ~~K~~N-2 are to be used as guidelines subject to modification (modified or expedited) as warranted. It is also recognized and understood that under the Transmission Provider's OATT, there are certain FERC mandated timelines that are applied to Transmission Service Requests ("TSRs") and Generator Interconnection Service Requests ("GISRs") that may conflict and be of higher priority than the Local Process. Therefore, Transmission Provider's receipt of TSRs and/or GISRs may require the modification, from time to time, of the timelines described below.

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



Local Transmission Network Planning Process – Process Description Overview:

- The Transmission Provider, which is ultimately responsible for the development of the Transmission Provider's annual 10 Year Expansion Plan, will lead the Local Process on a coordinated basis with the Customers/Stakeholders. This Local Transmission Planning Process will be implemented in such a manner as to ensure the development of the Local Transmission Plan in a timely manner. The Transmission Provider will facilitate each meeting throughout the process. The Transmission Provider will encourage an open dialogue and the sharing of information with Customers/Stakeholders (subject to confidentiality requirements and FERC Standards of Conduct[4]) in the development of the Local Transmission Plan.
- Customers/Stakeholders are invited to participate in the Transmission Provider's Local Process.
- The Local Process will comply with the FERC nine principles as well as the provisions below.

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[4] The provision for handling of information also applies to all steps of the Local Process.

- All annual initial kick-off meetings will be open to all Customers/Stakeholders and noticed by the Transmission Provider to all Customers/Stakeholders with sufficient time to arrange for travel planning and attendance (two week minimum). The annual initial kick-off meeting will be a face-to-face meeting; otherwise, with the consent of the Customers/Stakeholders, meetings may be organized as face-to-face meetings, conference calls, web-ex events, etc., wherein the dialogue and communications will be open, direct, detailed, and consistent with the FERC Standards of Conduct and confidentiality requirements.
- The Customers/Stakeholders may initiate the dispute resolution process at any point in the Local Process where agreement between the Transmission Provider and Customer(s)/Stakeholder(s) cannot be reached.
- The entities generally responsible for undertaking the tasks described below are designated as the TP (Transmission Provider) and/or the S (Customers/Stakeholders).

The study process will include the following steps:

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

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

- Load forecasts, if appropriate:
  - Coincident and non-coincident Peak load forecasts will be provided for the subsequent 11 years, for each summer and winter peak season, with real power and reactive power values for each load serving substation (reflected to the transformer high-side) or delivery Point, as applicable.
- Transmission Delivery Points, if appropriate:
  - Delivery Point additions and/or Delivery Point modifications that have not previously been noticed to the Transmission Provider will be communicated by the Customer/Stakeholder to the Transmission Provider via the standard Delivery Point Request letter process.

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

- Network Resource Forecast, if appropriate:

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

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

- If hardcopy, the Transmission Provider will provide the mailing address;

- If faxed, the Transmission Provider will provide the fax number;

- If e-mailed, the Transmission Provider will provide the e-mail address;

- If delivered to a password protected FTP site or e-vault, the Transmission Provider will provide the folder for the data, the contact person to be notified of the data delivery, etc. consistent with confidentially requirements and FERC Standards of Conduct. The Transmission Provider will provide the name and contact details for the Transmission Provider point of contact for data submittal questions.

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

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

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

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

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

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

- The Transmission Provider will, approximately two (2) weeks prior to the second quarter initial kick-off meeting (or other date, if Transmission Provider and Customers/Stakeholders agree), communicate via e-mail with all Customers/Stakeholders the schedule/coordination details of the Transmission Provider's Local Process kick-off meeting(s). Customer/Stakeholder shall provide to Transmission Provider a confirmation of their intent to participate in the initial kick-off meeting at least three (3) days prior to such meeting. (TP)
- The Transmission Provider will, in advance of the Kick-off meeting(s), with sufficient time for Customer/Stakeholder review, provide to the Customers/Stakeholders a proposed study schedule, the NERC and FRCC Reliability Standards that will apply to the study, and/or guidelines that will apply to the study and Transmission Provider developed criteria that will apply to the study. (TP)
- The initial Kick-off meeting in the second quarter of the calendar year will begin the Transmission Provider's Local Process. The Transmission Provider will review and validate the input data assumptions received from each Customer/Stakeholder, discuss the proposed study schedule, and discuss the study requirements, which will include, but not be limited to, the following:

- The methodologies that will be used to carry out the study (TP/S)
- The specific software programs that will be utilized to perform the analysis (TP)
- The Years to study (TP/S)

- The load levels to be studied (e.g., peak, shoulder and light loads) (TP/S)
- The criteria for determining transmission contingencies for the analysis (i.e. methods, areas, zones, voltages, generators, etc.) (TP/S)
- The Individual company criteria (i.e., thermal, voltage, stability and short circuit) by which the study results will be measured (TP/S)
- The NERC reliability standards by which the study results will be measured (TP/S)
- The FRCC reliability standards and requirements by which the study results will be measured (TP/S)
- Customer/Stakeholder proposed study scenarios for Transmission Provider consideration in the analysis (TP/S)

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

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

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

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

- The Transmission Provider will perform the study analyses (verification that thermal, voltage, stability and short circuit values meet all planning criteria) and produce the initial unfiltered, un-processed input data, output data, and files. (TP).

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

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

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

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

- The Transmission Provider will identify potential solutions / mitigation proposals to address problems / issues. (TP)
- The Transmission Provider will document, electronically post, and provide notice to the Customers/Stakeholders of the posting of the identified potential solutions / mitigation proposals to address problems / issues related to the impacted Customer(s)/Stakeholder(s).
- The Customers/Stakeholders may provide alternative potential solutions / mitigation proposals for the Transmission Provider to consider. Such information shall be provided in IDEV format and posted. (TP/S)
- The Transmission Provider will determine the effectiveness of the potential solutions through additional studies (thermal, voltage, stability and short circuit). The Transmission Provider may modify the potential solutions, as necessary, such that required study criteria are met. (TP)
- The Transmission Provider will identify feasibility, timing and cost-effectiveness of proposed solutions that meet the study criteria. (TP/S)

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

- The Transmission Provider, in consultation with the Customers/Stakeholders, will compare the alternatives and select the preferred solution / mitigation alternatives based on feasibility, timing and cost effectiveness that provide a reliable and cost-effective transmission solution, taking into account neighboring transmission providers' transmission plans. (TP/S)
- In case of Transmission Provider and Customer/Stakeholder dispute, the dispute resolution process described in Section 6.1 will be utilized. (TP/S)

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

- The Transmission Provider will submit the Transmission Provider's proposed local transmission network plan results (the Transmission Provider's 10 Year

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

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

Appendix 2 to Attachment ~~K~~N-2

FRCC Quorum and Voting Sectors

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

A Quorum

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

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

B. Voting

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

Sector Votes

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

ATTACHMENT ~~L~~O

~~**Creditworthiness Procedures**~~

CREDITWORTHINESS PROCEDURES

1. CP&L Zone and FPC Zone

1.1 Credit Review:

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. The credit review procedures shall consist of an evaluation of the Transmission Customer's ability to meet the creditworthiness criteria set out in Section 1.2. A credit review shall be conducted for each Transmission Customer not less than annually, or upon reasonable request by the Transmission Customer.

1.2 Creditworthiness:

A Transmission Customer that meets the following requirements shall not be required to provide any form of security against the risk of nonpayment for any type of service, including deposits that otherwise would be required pursuant to Sections 17.3, 29.2 and 37.4:

(i) The Transmission Customer is not in default of its payment obligations under Section 7.3 of this Tariff; and

(ii) It meets one of the following criteria:

a. The Transmission Customer has been in business at least one year and has a credit rating of at least Baa2 (Moody's) or BBB (Standard & Poors); or

b. The Transmission Customer has been in business at least one year, and provides its most recent financial statement to the Transmission Provider which demonstrates that the Transmission Customer meets standards that are at least equivalent to the standards underlying credit ratings of Baa2 (Moody's) or BBB (Standard and Poors), provided that if the Transmission Customer is found to be not creditworthy pursuant to this paragraph b, the Transmission Provider will inform the Transmission Customer of the reasons for that determination; or

c. The Transmission Customer is a borrower from the Rural Utilities Service ("RUS") and has a Times Interest Earned Ratio of 1.05 or better and a Debt Service Coverage Ratio of 1.00 or better in the most recent calendar year, or is maintaining the Times Interest Earned Ratio and Debt Service Coverage Ratio as established in the Transmission Customer's RUS Mortgage; or

d. The Transmission Customer is a municipality or a rural electric cooperative that has taken transmission service from the Transmission Provider for at least one year; or

e. The Transmission Customer's parent company meets the criteria set out in (i) and (ii)(a), (b), (c) or (d)) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of transmission service.

1.3 Requirements for Non-Creditworthy Customers:

A Transmission Customer that does not meet the creditworthiness criteria set out in Section 1.2 above shall comply with one of the following:

(i) Not less than five days prior to the commencement of service, the Transmission Customer shall provide an unconditional and irrevocable letter of credit or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that is equal to the lesser of the total charge for service or the charge for 90 days of service; or

(ii) For service for one month or less, the Transmission Customer shall pay the total charge for service by the later of five business days prior to the commencement of service or the time when it makes the request for transmission service; or

(iii) for service of greater than one month, the Transmission Customer shall pay for each month's service not less than five business days prior to the beginning of the month. For Network Integration Transmission Service customers, the advance payment for each month shall be based on a reasonable estimate by the Transmission Provider of the charge for that month.

The Transmission Provider shall pay interest on any prepayments made pursuant to this Section 1.3 at the rates established pursuant to 18 C.F.R. § 35.19a(a)(2)(iii). The deposits provided for in Sections 17.3, 29.2 and 37.4 shall not be required.

1.4 <u>Changes in Creditworthiness Status</u>:

If a Transmission Customer that originally meets the requirements of Section 1.2 subsequently fails to meet tho*se requirements at any time after it requests transmission service but before the termination of that service, it shall within five business days of notification in writing by the Transmission Provider either prepay for the next 30 days of transmission service or provide an unconditional and irrevocable letter of credit or alternative form of security acceptable to the Transmission Provider in an amount equal to the charge for the next 30 days of transmission service; and within 30 days of such notification shall meet the requirements of Section 1.3. The Transmission Customer has 5 days from the notification date to challenge the credit findings of the Transmission Provider.

1.5 Suspension of Service:

The Transmission Provider may suspend service to a Transmission Customer who does not meet the creditworthiness standards of Section 1.2 under the following circumstances;

(i) If the Transmission Customer qualifies for service pursuant to Section 1.3 as a result of providing a letter or credit or alternative form of security, it does not pay its bill within 20 days of receipt as required by Section 7.1, and it has not initiated a billing dispute in accord with Section 7.3, the Transmission Provider may suspend service 30 days after written notice to the Transmission Customer and the Commission that the service will be suspended unless the Transmission Customer pay its bills.

(ii) If the Transmission Customer qualifies for service as a result of committing to prepay for service pursuant to Section 1.3(ii) or Section 1.3(iii) above, and it fails to prepay for service as provided in such section, the Transmission Provider may suspend service immediately upon written notice to the Transmission Customer and the Commission.

(iii) If the Transmission Customer loses its creditworthy status as a result of circumstances other than a default of its payment obligations and it fails to meet the credit security requirements of Section 1.4, but it either pays its bills within the time period provided in Section 7.1 or initiates a billing dispute in accord with Section

7.3, the Transmission Provider may suspend service 30 days after written notice to the Transmission Customer and the Commission that the service will be suspended unless the Transmission Customer meets the credit security requirements of Section 1.3.

(iv) If the Transmission Customer loses its creditworthy status because it is in default of its payment obligations under Section 7.3 and it fails to meet the requirements of Section 1.4, the Transmission Provider may suspend service five business days after written notice to the Transmission Customer and the Commission that service will be suspended if the Transmission Customer does not meet the requirements of Section 1.4.

The suspension of service shall continue only for as long as the circumstances that entitle the Transmission Provider to suspend service continue. A Transmission Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

2. DEC Zone

2.1 Credit Review:

A Transmission Credit Limit will be established for each Transmission Customer pursuant to Section 2.2. For the purpose of determining the creditworthiness of a Transmission Customer, the Transmission Provider will conduct a credit review to evaluate the Transmission Customer's ability to meet the creditworthiness standard set out in Section 2.3 of this document. A credit review will be conducted at the time that a new Transmission Customer submits a Completed Application or an existing Transmission Customer seeks to increase its established Transmission Credit Limit. In addition, the Transmission Provider may perform credit reviews on a periodic basis to ensure continuing compliance.

2.2 Transmission Credit Limit:

(i) A Transmission Credit Limit will be established for each Transmission Customer based on a reasonable estimate of the maximum amount of transmission service that the Transmission Customer expects it will use over any five consecutive month period during the duration of its Service Agreement.

(ii) A Transmission Customer may seek to establish a new Transmission Credit Limit based on changed circumstances regarding the estimated maximum amount of transmission service that the Transmission Customer expects it will use over any given five consecutive month period, as long as it meets the creditworthiness standard set forth in Section 2.3.

2.3 Creditworthiness Standard:

In order to be found creditworthy, the Transmission Customer must meet the following standard:

(i) The Transmission Customer is not in default of its payment obligations, if any, under Part I, Section 7.3 of the Tariff; and

(ii) The Transmission Customer meets one of the following four criteria:

a. The Transmission Customer has been in business at least one year and has a credit rating on senior unsecured debt of at least Baa3 (Moody's) or BBB- (Standard & Poors) where, if rated by both agencies, the lower of the two ratings controls (*see* Appendix A for credit rating scales); or

b. The Transmission Customer is a borrower from the Rural Utilities Service ("RUS") and demonstrates to the Transmission Provider that it is maintaining the times interest earned ratio and debt service coverage ratio as established in the Transmission Customer's RUS Mortgage (or if not specified in the Mortgage, has a times interest earned ratio of 1.10x or better and a debt service coverage ratio of 1.10x or better in the most recent calendar year); or

c. The Transmission Customer's parent company meets the criteria set out in (i) and (ii)(a) or (b) above, and the parent company provides a written guarantee (in a form acceptable to the Transmission Provider), that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of transmission service; or

d. The Transmission Customer:

1. Has been in business at least one year;

2. Provides reasonably current audited annual financial statements (and current quarterly financial statements if available) to the Transmission Provider; and

3 Demonstrates to the Transmission Provider's satisfaction that it meets standards that are at least equivalent to the standards underlying the credit ratings of Baa3 (Moody's) or BBB- (Standard and Poors) on senior unsecured debt. For purposes of making this determination, the Transmission Provider will provide the audited financial statements and other relevant information concerning the Transmission Customer to the Credit Risk Management group, which will assign the Customer an "Internal Risk Rating" as further described in Appendix A. Based on the overall information garnered by the Transmission Provider, including but not limited to the Internal Risk Rating and information provided by the Transmission Customer, the Transmission Provider will determine the creditworthiness of the Transmission Customer.

If a Transmission Customer is determined to not meet the creditworthiness standard, the Transmission Provider will inform the Transmission Customer of the reasons for that determination and the Transmission Customer may dispute this finding pursuant to Section 2.6.

2.4 Security Requirements:

A Transmission Customer that does not meet one of the creditworthiness standards set out in Section 2.3 above shall comply with one of the following:

(i) Not less than five days prior to the commencement of service, the Transmission Customer shall provide in a form acceptable to the Transmission Provider, an unconditional and irrevocable letter of credit issued by a financial institution rated at least A- by S&P (for senior unsecured debt) with greater than $10 billion in assets or an alternative form of security that is equal to the lesser of the total charge for service or the charge for five months of service; or

(ii) For service of one month or less, the Transmission Customer shall pay the total charge for service by the later of five business days prior to the commencement of service or the time when it makes the request for transmission service; or

(iii) For service of greater than one month, the Transmission Customer shall pay for each month's service not less than five business days prior to the beginning of the month. For Network Integration Transmission Service customers, the advance payment for each month shall be based on a reasonable estimate by the Transmission Provider of the charge for that month.

2.5 Changes in Creditworthiness Status:

(i) If a Transmission Customer that originally meets the creditworthiness standard of Section 2.3 subsequently fails to meet those requirements at any time after it submits a Completed Application but before the termination of service, it shall within five business days of notification by the Transmission Provider either prepay for the next 30 days of transmission service or provide an unconditional and irrevocable letter of credit meeting the standards noted in 2.4(i) above or an alternative form of security acceptable to the Transmission Provider in an amount equal to the charge for the next 30 days of transmission service; and within 30 days of such notification shall meet the requirements of Section 2.4.

(ii) If requested by the Transmission Customer, the Transmission Provider, within three business days, must provide a written explanation detailing the justification for a change in the Transmission Customer's creditworthiness status.

2.6 Procedures for Contesting Determination of Creditworthiness Status:

Within 5 business days of receiving notice of the need for security, or if a finding is made that the Transmission Customer does not satisfy the creditworthiness standard of Section 2.3, a Transmission Customer may, in good faith, contest this determination by providing additional information addressing the Transmission Provider's concerns. If after reviewing the additional information submitted by the Transmission Customer, the Transmission Provider continues to require security and the Transmission Customer contests this determination, the Transmission Customer must provide the required security and the matter shall be referred to dispute resolution pursuant to Section 12 of the Tariff.

Appendix A

The following table shows the credit rating scales of the major rating agencies.

Credit Rating Scales*	S&P	Moody's
Investment Grade	AAA	Aaa
	AA+	Aa1
	AA	Aa2
	AA-	Aa3
	A+	A1
	A	A2
	A-	A3
	BBB+	Baa1
	BBB	Baa2
	BBB-	Baa3
Below Investment Grade	BB+	Ba1
	BB	Ba2
	BB-	Ba3
	etc	etc

* For purposes of establishing a Transmission Credit Limit, the rating referenced will be the rating for senior unsecured obligations (or the overall issuer rating if senior unsecured rating is not available), rather than that assigned to secured indebtedness. Debt ratings based on the acquisition by the issuer of insurance on the underlying debt shall not be considered as reflective of the creditworthiness of the issuer.

Internal Risk Ratings will be developed by the Duke Energy Corporation Credit Risk Management group based on an entity's audited financial statements and other available relevant information. Factors likely to have an impact on the Internal Risk Rating assigned to a customer include the following:

- Strength of balance sheet, as indicated by degree of financial leverage, interest coverage ratios, etc.;
- Strength of earnings and cash flow indicators;
- Market structure within which the entity operates, and its competitive positioning within that structure;
- Impact of regulation, including overall regulatory environment;
- Ability to establish and/or maintain adequate levels of customer rates;
- Overall size of entity relative to expected credit requirements;

- Adequacy of access to capital given capital expenditure requirements and/or other financing needs (including debt refunding);
- Volatility of earnings, cash flow, interest, and overall performance;
- Degree of exposure to adverse business, financial, or economic conditions;
- Susceptibility to business concentration risk; and
- Indications of potential bankruptcy, payment default, or other signs of financial distress.

ATTACHMENT ~~T~~P

METHODOLOGY FOR CLUSTERING TRANSMISSION STUDIES

1. CP&L Zone and FPC Zone

Cluster Study Determination

The Transmission Provider may decide, either on its own initiative or in response to a request from an Eligible Customer, to perform a System Impact Study and/or a Facilities Study of multiple requests for transmission service in a single study to determine what transmission facilities are necessary to provide the requested service (a "Cluster Study") if the following criteria are met: (1) the Transmission Provider has received more than one request for Long-Term Firm Point-to-Point Transmission Service and/or Network Integration Transmission Service that will require a System Impact Study; (2) the requests are for overlapping time periods of service; and (3) the requested service will be limited by some of the same facilities. The Transmission Provider will not include in a Cluster Study any request for service as to which the Transmission Provider has already provided to the Eligible Customer the first draft of a System Impact Study with respect to that request. If the Transmission Provider determines that it will not perform a Cluster Study that has been requested by an Eligible Customer, it will post on the OASIS a brief statement explaining the reasons that it cannot accommodate an Eligible Customer's request.

Procedures for Clustered System Impact Studies and Facilities Studies

If the Transmission Provider decides to perform a Cluster Study, it will notify each affected Eligible Customer, provide a brief explanation of the reasons why it has decided to perform a Cluster Study, and tender a System Impact Study Agreement or a Facilities Study Agreement, as appropriate, that states that the Eligible Customer's request for service will be part of a Cluster Study. The procedures of Sections 19 and 32 of the Tariff shall apply to Cluster Study Agreements and Cluster Studies, except that the 60-day periods for the completion of System Impact Studies and Facilities Studies established in Sections 19.3, 19.4, 32.3 and 32.4 shall be computed based on the last date on which an Eligible Customer whose request for service is studied in the Cluster Study must either execute and return a System Impact Study Agreement or a Facilities Study Agreement, as applicable.

The costs of the Cluster Study shall be shared equally among the Eligible Customers whose requests for service are included in the Cluster Study. If the Transmission Provider includes in a Cluster Study a request for service as to which it has already commenced a System Impact Study, the Eligible Customer must pay: (1) the Eligible Customer's share of the cost of the Cluster Study; and (2) if the Eligible Customer requested inclusion in the Cluster Study, the cost that the Transmission Provider has incurred with respect to the System Impact Study.

If an Eligible Customer whose request for service is studied in a Cluster System Impact Study does not execute a Facilities Study Agreement, execute a Service Agreement or request the filing of an unexecuted Service Agreement within the time established in Sections 19.3, 19.4, 32.3 or 32.4, as applicable; or an Eligible Customer whose request for service is studied in a Cluster Facilities Study does not execute a Service Agreement or request the filing of an unexecuted Service Agreement within the time established in Sections 19.4 or 32.4, as applicable, that Eligible Customer's Application shall be deemed terminated and withdrawn. In such event, the Transmission Provider shall re-study the requests for service for the remaining Eligible Customers in the Cluster Study. The remaining Eligible Customers shall bear equal shares of the costs of the re-study.

Transmission Service Cost Determination

The Transmission Provider will determine whether the facilities to be constructed are Network Upgrades or Direct Assignment Facilities based on the Commission policies. Transmission Customers shall be responsible for paying for transmission service based on the terms of Sections 27 and 34 of the Tariff.

Network Upgrades: Each Transmission Customer whose request for service has been studied in the Cluster Study and whose request for service contributes to the need for Network Upgrade(s) shall be deemed to be responsible for a pro rata share of the cost of those Network Upgrade(s) based on the amount of MW of service that it has requested. The Transmission Provider shall determine whether the Transmission Customer pays for transmission service at the embedded cost of service or at the incremental cost of the Network Upgrades based on the Commission's transmission pricing policies for Network Upgrades.

Direct Assignment Facilities: In the event a Direct Assignment Facility is identified and assigned to specific Transmission Customers whose requests for service are included in the Facilities Study, the cost of such Direct Assignment Facilities shall be borne by the specific Transmission Customers in accord with the Commission's transmission pricing policies for Direct Assignment Facilities.

2. DEC Zone

An Eligible Customer may request that the Transmission Provider cluster specific long-term transmission requests provided that the requests are in sequential order. Prior to submitting a cluster request to the Transmission Provider, the Eligible Customer must contact all of the Eligible Customers whose requests it proposes to be clustered and obtain their written consent that they are willing to have their request clustered with the other identified requests. The Transmission Provider will determine whether to cluster the requests of the Eligible Customers that have provided consent to a proposed cluster. In determining whether to cluster, the Transmission Provider will offer clustering if the Transmission Provider determines that there are potential economic benefits in clustering because the potential transmission upgrades are large enough that the upgrades can accommodate more than one transmission service request, but the overall cost of upgrades may otherwise be prohibitive for only one or two customers. The Eligible Customers in the cluster will execute a single System Impact Study Agreement and will be given a single queue date (the date of the last Completed Application in the cluster). The cost of the System Impact Study will be shared equally among the Eligible Customers in the cluster.

If the Transmission Provider determines to cluster the identified requests, it will perform a single System Impact Study for the clustered requests. After the results of the System Impact Study have been provided, an Eligible Customer may opt out of the cluster prior to signing a Facilities Study Agreement and its Application will be deemed terminated and withdrawn. The Eligible Customer opting out must pay for any revised System Impact Study caused by its decision to opt out. If the System Impact Study determines that transmission system additions are required, the remaining clustered Eligible Customers will execute a single Facilities Study Agreement. The cost of the Facility Study will be shared equally among the Eligible Customers in the cluster. After the results of the Facilities Study have been provided, an Eligible Customer may opt out of the cluster prior to signing a Service Agreement and its Application will be deemed terminated and withdrawn. The Eligible Customer opting out must pay for any revised System Impact Study and revised Facilities Study caused by its decision to opt out after the Facilities Study is completed.

Those Transmission Customers that have not opted out must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27 (Point-to-Point Customers) or Section 34 (Network Customers) of the Tariff. For purposes of compensation, all requests that are clustered are treated as simultaneous transmission service requests and cost responsibility allocated pro rata based on the amount of MW requested. Nothing in this Attachment impacts the "higher of" pricing policy applicable to service under the Tariff.

~~ATTACHMENT Q~~

~~Reserved for future use~~

ATTACHMENT ~~M~~Q
Procedures For Changing The Real Power Loss Factor
[FPC Zone Only]

The Real Power Loss Factors applicable to delivery at transmission voltages and delivery at distribution voltages are set out in Sections 15.7, 28.5 and 36.11 of the Tariff. The Transmission Provider shall separately state the losses related to Generation Step-Up Transformers. The procedures for the modification of the Real Power Loss Factors are as follows:

1. Not later than March 15 of each year, the Transmission Provider shall provide existing Transmission Customers and intervenors in the most recent transmission rate proceeding the loss rate that the Transmission Provider proposes to place in effect beginning May 1 of that year, based on data for the prior calendar year, plus all data required to support and validate that proposed loss factor. The Transmission Provider shall respond to all reasonable requests from such Transmission Customers and intervenors for additional data.

2. Unless otherwise agreed, the Transmission Provider shall tender the previously provided loss factors for filing not later than April 30 of each year and shall request that the loss factors go into effect on May 1 of that year. All such filings shall be treated as Section 205 rate changes, regardless of whether the proposed loss factor is an increase, a decrease or is unchanged from the loss factor then in effect, and the Transmission Provider shall bear the burden of proof. The Transmission Customers and intervenors reserve all of their rights under Sections 205 and 206 of

The remaining page to Attachment Q
contains no changes of substance and is not included.

ATTACHMENT R

FORM OF SERVICE AGREEMENT FOR NETWORK CONTRACT DEMAND TRANSMISSION SERVICE

~~**Form of Service Agreement For Network Contract Demand Transmission Service**~~

1.0 This Service Agreement, dated as of _______________, is entered into, by and between ~~Carolina Power & Light Company/~~Florida Power Corporation ("Transmission Provider"), and ____________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Network Contract Demand Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 37.4 of the Tariff or has met the creditworthiness standards of Attachment ~~L~~O of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Network Contract Demand Transmission Service in accordance with the provisions of Part IV of the Tariff and this Service Agreement.

5.1 The Transmission Customer is responsible for replacing Real Power Losses associated with all transmission service in accordance with Section 36.11 of the Tariff. The Transmission Customer must identify the party responsible for supplying Real Power Losses before the transaction.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Transmission Customer:

~~7.0 [CP&L Zone: When load is being served by the Transmission Customer in the CP&L Zone, the Transmission Customer shall maintain a power factor of 100% to 90% lagging at each point of delivery determined on the basis of the 60-minute metered or computed reactive demand (kVar) for each hour of the month and the corresponding 60-minute metered or computed kilowatt demand for that hour. In addition, the Transmission Customer shall maintain a power factor of 100% to 95% lagging at each point of delivery, determined on the basis of the 60-minute metered or computed kilowatt demand at the time of CP&L's monthly transmission system peak and the corresponding 60-minute reactive demand (kVar) for that hour. To the extent the Transmission Customer owns or operates reactive devices which could cause reactive power to flow onto the CP&L system, CP&L and the Customer will develop procedures governing the Customer's delivery of reactive power to the CP&L system. In the event that the Transmission Customer does not satisfy the power factor requirements outlined above or the Parties cannot agree on the procedures governing the customer's delivery of reactive power, CP&L reserves the right to make a unilateral filing with FERC under Section 205 of the Federal Power Act seeking authorization to either (i) assess appropriate charges to the Transmission Customer for reactive power supplied to the Transmission Customer by CP&L up to the level of minimum power factor requirement, or (ii) install power factor correction equipment sufficient to bring the Transmission Customer's power factor into compliance with the power factor requirements, and to assess the Transmission Customer the reasonable cost of such equipment.]~~

~~[FPC Zone: The Transmission Customer shall maintain a minimum aggregate power factor for transmission Points of Delivery (voltages 69 kV and above) of 95% lagging at the time of the Transmission Provider's system peak for the months of June through September of each year. This aggregate power factor standard shall be applied to the Transmission Customer's delivery points located within each of the Transmission Provider's twelve distribution operating areas. The Transmission Customer's power factor for distribution Points of Delivery (voltages below 69 kV) will be adjusted down by 2% to convert to the transmission voltage level so they can be included in the aggregate power factor calculation described above. The Transmission Provider's twelve (12) distribution operating areas will also comply with the above aggregate power factor standard on a comparable individual basis. For the months of October through May of the year, the Transmission Customer will comply with mutually agreed power factor standards developed by the Network Operating Committee that will be applied on a comparable basis between the Transmission Provider's Native Load and the Transmission Customer's Network Load. By December 31 of every year, the Transmission Provider will review the actual aggregate power factor of the Transmission Customer's delivery points in each of the Transmission Provider's distribution operating areas and the Transmission Provider's actual power factor in each distribution operating area to determine compliance with the~~

~~above standard. For any areas of non-compliance, the Transmission Customer and the Transmission Provider will rectify the non-compliance within one year. If the Transmission Customer does not comply with the power factor standard within one year after written notice of non-compliance, the Transmission provider will have the right to unilaterally install the required amount of reactive equipment on the Transmission System to correct the deficiency and bill the Transmission Customer on a lump sum or monthly basis for the cost of such equipment]~~

7.0 FPC Zone: The Transmission Customer shall comply with the power factor requirements set forth in OATT Attachment V.

8.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:______________________ ________________ _______________
Name Title Date

Transmission Customer:

By:______________________ ________________ _______________
Name Title Date

Specifications For Long-Term Network Contract Demand
Transmission Service

1.0 Term of Transaction: ____________________________________

Start Date: ____

Termination Date: _______________________________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt:_____________________________________

Delivering Party:_______________________________________

4.0 Point(s) of Delivery:____________________________________

Receiving Party:____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity):_____________________________________

6.0 Designation of party(ies) subject to reciprocal service obligation:____

____

7.0 Name(s) of any Intervening Systems providing transmission service:____

____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:________________________________

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge: ____________________

____

8.4 Ancillary Services Charges: __________________________

____

____

____

____

____

____

ATTACHMENT S

~~**Index Of Network Contract Demand Transmission Customers**~~

INDEX OF NETWORK CONTRACT DEMAND TRANSMISSION CUSTOMERS

See Transmission Provider's Electric Quarterly Report at the following Internet address: http://www.ferc.gov/docs-filing/eqr/data/spreadsheet.asp

ATTACHMENT T

~~METHODOLOGY FOR CLUSTERING TRANSMISSION STUDIES~~

[RESERVED]

[FPC Previous Attachment T is Attachment P in the Joint OATT]

~~OATT~~ ATTACHMENT U

FPC's RATE TREATMENT OF NEW TRANSMISSION RADIALS

a) <u>Transmission radial facilities commencing service after May 31, 2010 ("new transmission radials"):</u>

i. The costs of Transmission Provider's new transmission radials that serve its retail customers' loads and that are not considered part of the integrated grid under FERC guidelines and the cost of any upgrades to these new transmission radials will be excluded from the base rates for transmission services under the Transmission Provider's Formula Rate. OATT Attachment U.1 describes the changes to the Transmission Provider's Formula Rate to exclude the costs of these facilities. If some or all of the new transmission radial is later converted to an integrated transmission facility, the Transmission Provider's cost to integrate its previously non-integrated radial facility and the unrecovered cost of the previously non-integrated radial facility, or such portion that becomes integrated with the bulk transmission grid, would be recovered in Transmission Provider's Formula Rate.

ii. The costs of Transmission Provider's new transmission radials that serve Transmission Customer loads (including a wholesale customer load not served under the OATT) and that are not considered part of the integrated grid under FERC guidelines and the cost of any upgrades to these new transmission radials will be excluded from the base rates for transmission services under the Transmission Provider's Formula Rate. If and to the extent that the Transmission Provider constructs and owns a new

The remaining pages to Attachment U and Attachments U.1 and U.2 contain no changes of substance and are not included.

ATTACHMENT V
POWER FACTOR REQUIREMENTS

[FPC ZONE]

Transmission Provider and Transmission Customer shall each have in place in the shortest practicable time, but under no circumstances later than forty-two (42) months after the Transmission Customer's service commences under the Tariff (referred to as the "Initial Compliance Period"), sufficient reactive compensation and control necessary to meet the power factor standard set forth herein. In the event that the Transmission Customer does not meet the power factor standard by the end of the Initial Compliance Period, Transmission Provider shall provide Transmission Customer with written notice of any alleged non-compliance (along with the data upon which such assertion is based), and, unless within sixty (60) days of receipt of such notice the Transmission Customer has initiated Dispute Resolution Procedures under Tariff Section 12 to determine whether it has met the power factor standards set forth herein, then Transmission Provider shall have the right to install such necessary equipment to meet the standard; provided, however, that the exercise of such right must be on a comparable basis as to all power factor aggregation zones of all other Transmission Customers and the Transmission Provider itself. Transmission Provider shall have the right to seek to recover such expenses from the Transmission Customer, consistent with the Dispute Resolution Procedures of the Tariff, based upon a showing, among other things, that Transmission Provider and all other Transmission Customers have met the power factor standard.

Each month, the Transmission Provider shall provide to the Transmission Customer a report of the power factor information as measured at the Point of Delivery for each Point of Delivery and by power factor aggregation zones for the Transmission Provider's Monthly Transmission System Peak for both the Transmission Provider and all Transmission Customers.

The remaining pages to Attachment V
contain no changes of substance and are not included.