FACILITY CONNECTION

REQUIREMENTS

December 22, 2009

Revision History

Revision	Date	Comments	
0	8/24/1999	Original document created to meet the requirements of NERC Planning Standard I.C.S1.M1.	
1	5/1/2001	Revised to include information regarding Dominion's generation interconnection procedures/process	
2	9/7/2005	Revised to reflect transition from old NERC Planning Standards to NERC Reliability Standards, including changing the naming convention of all referenced standards throughout the document.	
3	5/29/2007	Revised to reflect the following: – Updates to NERC Reliability Standards – Dominion's PJM Membership – References to new SERC regional studies processes	
4	12/22/2009	Revised to reflect the following : - PJM Generation Queue Changes Section 4 - General Revisions all sections	
Approval	12/22/2009	James R. Bailey Manager – Electric Transmission Planning	Signature: 

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- SECTION 1 -

INTRODUCTION

Dominion ("Company") has prepared this document for the purpose of complying with NERC's Reliability Standards, specifically standard FAC-001-0. It has been written to individually address the specific connection requirements of generation, transmission, and electricity end-user facilities. These facility connection requirements shall be adhered to by any requesting customer who wishes to establish a connection to the Company's transmission facilities. The Company will also adhere to these same requirements as it constructs additions to its transmission system. These requirements should be evaluated as a whole to determine the actions necessary to develop a complete interconnection request.

Transmission connections covered by this document include all generation resources, ties with transmission facilities owned by others, and customer substations at voltages of 69 kV or greater. It is not practical to include standards for all transmission connections since each connection is governed by the party requesting the connection and the transmission system at the point of customer connection. There are several factors that must be considered when connecting the Company's transmission system to (1) another transmission system, (2) new or additional generation, and (3) new or additional customer load. The evaluation of these factors requires a power system analysis of the transmission network under several different operating conditions:

- Normal operations (both peak and off peak).
- Operations with single contingency outages.
- Operations during periods of power transfers for both import and exports.

All connections must meet the Company's Planning Guidelines as stated in Exhibit A of this document.

- SECTION 2 -

GENERAL REQUIREMENTS

2.1. Interconnection Considerations

The determination of new transmission connection requirements for these uses will, at a minimum, consider the following factors:

2.1.1. Transmission Line Overloading

No single contingency outage on the Company's transmission system should result in loading greater than 94% of the Emergency MVA rating of any transmission facilitity. Should transmission facility loading exceed the 94% rating criterion during single contingency outages, additional transmission facilities may be required.

2.1.2. Transmission Line Voltage

The resultant voltage at any location on the transmission system for the loss of any one transmission circuit should not drop below 0.93 Per Unit (P.U.) on 230 kV and below and 1.01 P.U. on 500 kV System..

2.1.3. First Contingency Incremental Transfer Capability (FCITC)

The transmission system must be capable of importing and exporting power in excess of existing scheduled transfers between utilities. The system must be capable of handling this incremental transfer with any single facility (first contingency) out of service. Any new facilities connected to the transmission system (greater than 20 MW) should not significantly decrement FCITC's for transfers between utilities.

2.1.4. System Stability

System stability must be maintained under various operating conditions including faults and fault clearing conditions. Should transient stability studies indicate system instability, additional facilities beyond those suggested in this guideline may be required.

2.1.5. System Losses

Transmission losses reduce the amount of capacity and energy that is available to serve the customer load. This translates into additional capacity costs and increased fuel costs to make up for the demand and energy losses. These costs must be evaluated particularly if several different sites are being considered for the location of the new generation.

2.2. Reliability

These Facility Connection Requirements are needed to insure due consideration of reliability when developing the electric system. It is not a guarantee of reliable service. The following statement is in the Terms and Conditions of Electric Service on file with the Virginia State Corporation Commission and the North Carolina Utilities Commission:

"The Company will use reasonable efforts to furnish an uninterrupted supply. Therefore, should the supply of electricity fail or be interrupted or become defective through act of God, or the public enemy, or Federal, state, municipal, or other public authority, or because of accident, strikes or labor troubles, or any other cause beyond the reasonable control of the Company, the Company shall not be liable for such failure, interruption or defect."

All fault interrupting devices selected by the customer must be reviewed and approved by Dominion Electric Transmission for each interconnection point. In order to maintain Transmission reliability, each fault-interrupting device must be rated for full fault interrupting capability to satisfy the short circuit level requirements at the point of interconnection. Full fault interrupting capability is per the latest IEEE guidelines. As a

general rule, neither party should depend on the other for the protection of their respective equipment.

2.3. Joint Planning

2.3.1. Utility Interconnections

One of the roles of the Company's Electric Transmission Planning group is to perform short and long range planning studies to ensure delivery of bulk power to a continuously changing customer demand under a wide variety of operating conditions.

Should the Company receive an interconnection request that may impact a neighboring interconnected transmission system, the Company will initiate contact with that neighboring system for the purpose of coordinating those joint interconnection studies required to assess the impact of the interconnection request on the transmission systems of all affected parties.

All studies are performed in accordance with NERC Reliability Standards, which promote and maintain the reliability and security of the interconnected bulk power system. In order to fulfill this role, the Company has entered into various Inter-Area Reliability Agreements with neighboring utilities. The major purpose of these agreements is to further augment reliability and security of each member's bulk power supply system through coordination of planning and operation of their generation and bulk power transmission facilities. The following is a list of groups in which the Company actively participates in performing joint transmission interconnection studies.

- VACAR – Virginia-Carolinas Reliability Agreement
- SERC East-RFC (SER) Studies under the Eastern Interconnection Reliability Assessment Group (ERAG) Agreement
- SERC Intra-Regional Near-Term Studies
- SERC Intra-Regional Long-Term Studies

- ERAG – MMWG

Each of these groups has various Working Groups, Study Groups, Committees, Task Forces etc. that deal with various aspects of power system reliability and security issues. Various studies performed by these groups at the interconnection level include; power flows, stability, transfer capabilities, voltage collapse scenarios, tie-line re-closing angles, etc. The basic purpose of these studies is to measure the ability of the transmission network to transfer power in bulk amount from one area to another under the most limiting contingency assumptions that are judged to be credible. These studies can be used in identifying any deficiencies and the needed corrective actions, either through short term operating procedures or by future system upgrades. Transmission interconnections are planned such that the amount of power that can be transferred between and among the utilities, in addition to firm transactions, will be adequate to withstand the most severe credible generation and transmission contingency.

2.3.2. Wholesale Delivery Points

The Company provides transmission service to wholesale delivery points throughout its service area under Mutual Operating Agreement(s) (MOA). The criteria for serving wholesale customers is the same as that used to serve the Company's other customers and is predicated on "Good Utility Practices" and sound engineering and economic principles without regard for the ownership of the facilities.

Regardless of the generation source of supply to wholesale customers in the company's service area, all supply are delivered over the company's transmission facilities. Therefore, it is essential that wholesale customer load requirements be included in the company's planning process.

The following criteria applies to all joint planning between the Company and its wholesale customers:

- Contractual obligations must be observed.
- Studies must be based on sound engineering and economic principles consistent with long range system plans.
- *All applicable sections of the Company's Planning Guidelines as stated in Exhibit A of this document shall apply to the connection of any wholesale customer to the Company's transmission system*.

Joint Planning should be conducted annually with each wholesale customer. This joint plan includes a review of each company's construction program based on annually updated load forecasts for the general area. The procedure should be similar to the following:

- Load forecasts for each year up to ten years will be prepared by the wholesale customer for their area and by the company for the general area around the customer.
- High load growth areas should be identified as soon as possible.
- The customer and the company will each prepare preliminary studies of their respective systems for meeting the future load requirements identified by the forecasts.
- The customer and the company will exchange study information and, based on joint analysis, prepare a long-range plan.

There will be instances where deviations from the long-range plan will be necessary and where individual requests for delivery points are not covered. In these cases, the Company's Electric Transmission Planning Department shall review all projects for necessity, economics, and considerations of alternatives.

All delivery point requests should include a completed “Customer Request Form” as shown in Exhibit B.”

2.4. Supervisory Control and Data Acquisition

A Remote Terminal Unit ("RTU") may be required by the Company for gathering customer load and equipment status information that will be telemetered back to the Company’s appropriate Operations center. When required, the Company shall own and maintain the SCADA devices. The Customer shall provide at its expense a telecommunication data circuit to the operations center designated by the Company. The communication protocol for this data circuit(s) shall be specified by the Company. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by the Company.

Typical data requirements include the following:

- Status of interrupting devices
- MW flow
- MVAR flow
- Voltage at interconnection point

2.5. Telemetering and Metering

The Company shall specify, own, and maintain all meters and metering devices (including remote terminal units) used to measure the delivery and receipt of energy for payment purposes. Meter accuracy will be maintained within +/- 0.3%. Meters in service may be tested by the Company, the Commission, or any other lawfully constituted authority having jurisdiction over meter accuracy.

A voice telephone extension for the purpose of accessing the Company’s dial-up metering equipment and for communicating with the designated Company operations center shall be provided by the Customer at its expense.

In addition, the Customer shall also provide at its expense an extension of the Company's System Operations Center's PBX system in the control room of the Eligible Customer and equipment for purposes of generation scheduling and/or coordination of switching.

Typical generator and load metering data requirements include the following:

- kW
- kWh
- kVAR, leading and lagging
- kVAR-hour
- kV 2 -hour
- Voltage (to monitor voltage schedule compliance)

All metering instrument transformers installed must be strictly in accordance with the latest version of IEEE Standard C57.13 and, if applicable, ANSI Standard C93.1. The Metering Equipment installed must be capable of providing the minimum data specified by the Company.

2.6. Communications During Normal and Emergency Conditions

Complete, precise, and timely communication is an essential element for maintaining reliability and security of a power system. Under normal operating conditions, the major link of communication with various interconnects shall be by telephone lines. The Company and its Customer shall maintain communications which shall include, but not be limited to, system paralleling or separation, scheduled or unscheduled shutdowns, equipment clearances, periodic load reports, maintenance schedules, tagging of interconnection interrupting devices, meter tests, relay tests, billing, and other routine communication. In case of emergency or abnormal operating conditions, various communication channels may be used depending on the interconnect category as described in Sections III, IV, and V. Emergency telephone numbers should be agreed upon by both parties prior to the actual connect date. In case of general widespread

area announcements, the Company may also use public announcements through radio and television stations.

2.7. Voltage and Power Factor Control

The resultant voltage at any location on the transmission system for the loss of any one transmission circuit should not drop below 0.93 Per Unit (P.U.) for 230 kV and below.

Internal plant electrical system equipment design (e.g., transformers, tap settings, motors & other loads, generator/exciter, voltage regulator) should not restrict any mode of project operation within the Company's transmission system's allowable voltage range and regulation.

Transmission interconnected equipment should have the tap ranges and self-regulation necessary to operate within the transmission system's voltage range.

2.7.1. Network Schedule Voltage

All generators are expected to maintain the voltage schedule as required by the Transmission System Operator within the reactive capability of the generating units. To satisfy NERC Reliability Standard VAR-002-1, the Company requires all generator owners/operators to keep detailed records of as to when each generating unit does not comply with the Transmission System Operator's voltage schedule. The generator owner/operator shall be responsible for providing detailed reports on voltage deviations from the acceptable voltage ranges for a specified time period when requested by the company, SERC or NERC (within 30 days of a request).

2.7.2. Tap Settings of Generator Step-up and Auxiliary Transformers

Generator step-up and auxiliary transformers shall have their tap settings coordinated with the Company's transmission system voltage requirements.

Anytime the generator plans to replace any of the step-up or auxiliary transformers, the generator shall supply data relating to the transformer (e.g. size and type, available tap settings, impedance data, loss data etc.) to the Company for the purpose of determining the optimum tap setting. When tap changes are necessary, the Company shall provide the generator with a report that justifies the required tap setting changes and technical justification for these changes.

As required by NERC Reliability Standard VAR-002-1, the generator shall maintain detailed records of each generator step-up transformer and auxiliary transformer that shall include type of transformer, rating, nominal voltages, existing and available taps, impedance and loss data. When requested by the Company or Transmission System Operator, SERC or NERC it shall be the responsibility of the generator owner/operator to provide the above information on step-up and auxiliary transformers within five business days.

2.7.3 Design and Operational Requirements

The Company requires that generators meet the following design and operational requirements described in NERC Reliability Standard FAC-001-0 and its SERC Supplement . Design requirements include:

- The internal plant electrical system design (e.g., transformers, tap settings, motors & other loads, generator/exciter, voltage regulator) should not restrict any mode of project operation within the Company's transmission system's allowable voltage range and regulation.
- Transmission interconnected equipment should have the tap ranges and self-regulation necessary to operate within the Company's transmission system's voltage range.
- Voltage regulator load compensation, if required, to control voltage at a point beyond the generator terminals.

- Voltage regulator droop compensation, if required, for generators whose Terminals are directly connected (i.e., cross-compound, hydro)
- Coordination of excitation system settings with the Company.
- Transmission interconnection impact on adjacent areas' voltage or reactive compensation devices.

The following operational requirements must be adhered to:

- Load and/or generation operation to be within the acceptable voltage range and regulation as specified by the Company.
- Generator voltage regulator to be operated in automatic modes.
- Generator to maintain voltage schedules on transmission as specified by system operator
- Any reactive compensation devices to be coordinated with the Company.

2.8. Equipment Ratings

All current carrying equipment and devices shall be designed to carry the maximum loads that are predicted and used in load flow analysis. Loads exceeding “nameplate” or “normal” design capacities are only acceptable when allowed by manufacturers design documentation or standard industry practices.

Equipment BIL levels, shielding, and surge protective device application must meet requirements as determined by lightning and switching surge analysis, the latest IEEE C62 standards and the Company transmission and substation engineering standards. Also, equipment must meet all applicable ANSI/IEEE standards as outlined in the Company transmission and substation equipment specifications. The Company’s Manager Electric Transmission Lines or the Manager Electric Transmission Substations should be contacted for these references.

The Company’s methodology for determining its facility ratings is discussed in Dominion’s “Facility Ratings Methodology” document(FAC-008-0). The Company’s Manager – Electric Transmission should be contacted for these ratings.

2.9. Reactive Power Requirements

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Company pursuant to Good Utility Practices. The details regarding reactive power requirements for Transmission Customer, Generator and End User are covered under each respective section.

2.10. Short Circuit Conditions

All Facilities must equal or exceed the fault duty capability necessary to meet system short circuit requirements as determined through short circuit analyses and should fully comply with the latest ANSI/IEEE C37 standards for circuit breakers, switch gear, substations, and fuses.

The Company requires that generators meet the following design requirements described in NERC Reliability Standard FAC-001-0 and its SERC Supplement:

- Each Party is responsible for the short circuit capabilities of their own current carrying elements.
- Each Party is responsible for the ratings of their own interrupting devices. It is the responsibility of the Customer to coordinate their relays and devices with the Company's transmission system.
- Each Party shall supply the other existing and planned future fault current levels when requested.
- It is the responsibility of the Customer to notify the Company of any changes in their facilities that may cause an increase in fault currents (Generator and Transmission Customers).

2.11. System Protection and Controls

The end user is responsible for providing a protection system that will protect its equipment against disturbances on the Company's system and minimize the effects of disturbances from its facilities on the Company's equipment and transmission system.

The latest IEEE C37 and C57 guides and standards for protective relaying systems should be followed.

NERC Reliability Standards, operating voltage and proximity to a generating unit will be major considerations for establishing the required protection scheme on a transmission line that connects to the Company's transmission grid. *Further modifications of the required protection scheme will be necessary as NERC Standards are finalized and approved.* The following defines the present protection requirements for protecting lines connecting to the Company's transmission grid.

2.11.1 Dual Primary Phase and Ground Schemes

Protection schemes classified as Dual Primary are required for all transmission lines connecting to the Company's transmission grid. This scheme will require two independent high speed, pilot supervised phase and ground fault protection systems designated System 1 and System 2. Together these systems provide a redundant set of all normal primary and backup functions.

2.11.2 Protection System Components

The "protection system" arrangement selected by the customer must be compatible with the protection system used by the Company to protect the transmission grid. Compatibility will include protection philosophy, tripping speed, blocking speed, type of communication and communication (carrier) frequency.

All fault interrupting devices selected by the customer must be reviewed and approved by Dominion for each interconnection point. In order to maintain Transmission reliability, each fault-interrupting device must be rated for full fault interrupting capability to satisfy the short circuit level requirements at the point of interconnection. Full fault interrupting capability is per the latest IEEE guidelines. As a general rule, neither party should depend on the other for the protection of their respective equipment.

2.12. Synchronizing Facilities

Transmission breakers are closed to connect two energized lines only after the phase angle across the breaker is verified. This is accomplished by one of two methods. In the first method, manual closing utilizes a sync permissive switch. The switch must be turned on to allow breaker closing. Turning on the switch energizes a synchroscope, which shows the phase angle between the lines to be tied together. This method requires the Operator to determine that the angle is within limits.

The second method uses automatic reclosing relays, which initiates a close only after a synchro-verifier relay determines that the angle is within limits.

2.13. System Grounding

A bus is considered to be "effectively grounded" when the following relationships are true:

- $X_o/X_1 \leq 3$
- $R_o/X_1 \leq 1$

This relationship assumes $R_1/X_1 = 0$, which is a worst case condition. If one or both of these relationships are not true, the effective grounding should be checked more precisely by referring to the curves found in the “ABB *Transmission and Distribution Reference Book*”. The curves can be found in Chapter 18, page 626. The proper curve to use should be based on the actual R_1/X_1 ratio. Any set of ratios lying below the appropriate curve marked 80% will provide effective grounding for 80% lightning arresters standardly used on the Dominion Virginia/North Carolina Power system.

Facilities must be designed according to IEEE 80 and National Electric Safety Code. Studies must be performed to guarantee step and touch, as well as transferred, Voltages are limited to safe levels. Furthermore, testing must be performed to verify the integrity of the installed system.

The following chart shows the required structure ground resistance on all new Company transmission construction:

Type of Structure	Structure Ground Resistance Ohms		
	115kV	230kV	500kV
Wood (grounded steel crossarms)	25 (30)	25 (30)	20 (24)
Concrete	25 (30)	25 (30)	20 (24)
Steel	25 (30)	25 (30)	20 (24)
The ground resistances indicated above are: __ preferred; ( ) maximum allowable for new installations			

Table 1: Structure Ground Resistance

2.14. Responsibilities During Emergency Conditions

The Company may, consistent with Good Utility Practice, take whatever action or inaction with regard to its Transmission System it deems necessary during an Emergency Condition in order to: (i) preserve public health and safety; (ii) preserve the reliability of the Transmission System; (iii) limit or prevent damage; and (iv) expedite restoration of service. The Company shall use reasonable efforts to minimize the effect of such action or inaction on the Facility.

In case of emergency or abnormal operating conditions, various communication channels may be used depending on the interconnect category as described in Sections III, IV, and V. In case of general widespread area announcements, the Company may also use public announcements through radio and television stations.

2.15. Abnormal Frequency and Voltage Operation

The Company requires its Customers to meet the following design requirements described in NERC Reliability Standard FAC-001-0 and its SERC Supplement:

- *Consideration for abnormal voltage conditions*
- *Consideration for abnormal frequency conditions*
- *Relay coordination to maintain stability*
- *Load shedding implementation*

2.16. Inspection Requirements

Each Party shall perform routine inspection and testing of its facilities and equipment, including secondary low voltage control systems, in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Facility with the Company's Transmission System in a safe and reliable manner.

Each Party shall, at its own expense, have the right to observe the testing of any of the other Party's facilities and equipment whose performance may reasonably be expected to affect the reliability of the observing Party's facilities and equipment. Each Party shall notify the other Party in advance of its performance of tests of its facilities and equipment, and the other Party may have a representative attend and be present during such testing. If a Party observes any deficiencies or defects on, or becomes aware of a lack of scheduled maintenance and testing with respect to, the other Party's facilities and equipment that might reasonably be expected to adversely affect the observing Party's facilities and equipment, the observing Party shall provide notice to the other Party that is prompt under the circumstance, and the other Party shall make any corrections required in accordance with Good Utility Practice.

2.17. Power Quality

2.17.1 Flicker Requirements

Flicker will be assessed at the Point of Common Coupling (PCC) using an instrument in compliance with IEC 1000-4-15, except that the weighting curve

used to represent the response of the light bulb shall be based on the 120 volt lamp characteristics as recommended in UIE 96-10.

The flicker measured at the PCC shall be 0.8 or less for the short-term flicker (Pst) and 0.6 or less for the long term Flicker (Plt). The Pst and Plt values measured shall not be exceeded more than 1% of the time based on a probability distribution calculated for a one-week period.

2.17.2 Harmonic and Inter-Harmonic Requirements

Harmonic levels will be assessed at the PCC with an instrument that can take individual samples of voltage and current waveforms and determine the probability distribution of the individual harmonic levels for both the current and the voltage.

Harmonic distortion levels at the PCC shall meet the requirements of IEEE Standard 519-1992 with respect to the harmonic current components. Background harmonic voltage distortion levels at the PCC should be in compliance with the recommendations in IEEE 519-1992.

In addition, the individual inter-harmonic currents shall be limited to 25% of the values in IEEE 519-1992 and the THD calculation shall include the inter-harmonic components. The Inter-harmonics shall be calculated in 10 Hz increments. The current distortion levels specified in IEEE 519-1992 shall not be exceeded by more than 5% of the time based on a probability distribution calculated for a one-week period.

2.18. Maintenance

2.18.1. Maintenance Requirements

The Customer shall be responsible for the design, construction, installation, maintenance, and ownership of all Interconnection Facilities located on its side of the Interconnection Points. The Company shall be responsible for the design,

construction, installation, maintenance, and ownership of all Interconnection Facilities located on the Company's side of the Interconnection Points.

In order to perform certain maintenance, testing, and repair activities, the Company's transmission line(s) must be de-energized. Under this condition, station service power may be interrupted to the Customer. The Company will require periodic transmission line(s) outages to perform protective relay maintenance. The Company will coordinate protective system checks during these outages with the Customer.

The Company's circuit breaker(s) are required to be opened periodically in order to exercise the breaker mechanism. In instances where the breaker has not been operated for an extended period, the Company may manually operate the breaker. The Company will coordinate this and any other circuit breaker maintenance with the Customer.

The Company or the Customer may request, from time to time, routine switching of each other's equipment. In such cases, the Company and the Customer will provide reasonable notice to the other party of any equipment switching that affects electrical service to the other party.

2.18.2. *Maintenance Coordination*

Complete, precise, and timely communication is an essential element for maintaining reliability and security of a power system. Under normal operating conditions, the major link of communication with various interconnects shall be by telephone lines. Dominion Virginia/North Carolina Power and its Customer shall maintain communications which shall include, but not be limited to, system paralleling or separation, scheduled or unscheduled shutdowns, equipment clearances, periodic load reports, maintenance schedules, tagging of interconnection interrupting devices, meter tests, relay tests, billing, and other routine communication.

The Parties shall coordinate inspections, Planned Outages, and maintenance of their respective equipment, facilities and systems so as to minimize the impact on the availability, reliability and security of both Parties' systems and operations.

Each Party shall provide the other with reasonable notification for routine maintenance, operational tests, inspection activities and Revenue Meter tests. For such activities that do not require major equipment or system outages, the Party performing the same shall provide the other Party with at least twenty-four (24) hours prior written notice. For such activities that will require major equipment or system outages, the Party performing the same shall provide the other Party with not less than seventy-two (72) hours prior written notice.

2.19. *Provisions for Future Changes*

Either Party shall notify the other in advance of any changes in their respective facilities, which reasonably can be expected to affect the proper coordination of protective devices of either party.

In no event shall the Company be obligated to pay all or any part of the costs resulting from any relocation or rearrangement of the Interconnection Facilities which is initiated by the Customer. The Company and Customer shall discuss proposed relocation and rearrangement of the Interconnection Facilities prior to the commencement of such relocation or rearrangement. The Customer shall pay for or perform, or shall cause to have paid for or performed, such relocation or rearrangement, provided that nothing herein shall deprive the Customer of any right it has to challenge the necessity of any such relocation or rearrangement prior to commencement.

The Customer shall provide, at its expense, all protective devices required by Dominion to conform with Good Utility Practices.

- SECTION 3 -

TRANSMISSION CONNECTION REQUIREMENTS

3.1. Interconnections with Other Utilities

Transmission interconnections are planned such that the amount of power that can be transferred between and among utilities, over the above firm purchases, sales and transfers, will be adequate to withstand the most severe probable contingency. The minimum power transfer requirement under these emergency conditions will depend upon the number of generation units, their characteristics, and many other factors.

The North American Electric Reliability Corporation (NERC), and the eight (8) regional reliability councils have developed mandatory, enforceable NERC Reliability Standards which must be fully complied with to assure reliable electric service to all areas of the United States. The Company is a member of the SERC Reliability Corporation (SERC) and is guided by the criteria set forth by that council. In addition, the following criteria are used in planning the transmission system. These criteria apply to conditions of expected firm power transfers among the Company and its neighboring power systems and to the official company load forecasts that are based on “normal” weather and projected, prevailing economic conditions.

As with generating capacity, reserve capacity must also be provided in the transmission system to recognize the effects of deviations from normal weather and of load forecast uncertainty and variations in day to day operating conditions. In the application of the following criteria an allowance of 6% should be made in circuit loading.

3.2. Transmission Planning Criteria

The transmission system should be capable of transferring reasonable amounts of power, in excess of firm purchases, sales and transfers, between and among the Company and the neighboring utilities with (i) all transmission facilities in service or (ii)

with one transmission circuit or transformer out of service. Under these conditions, the maximum continuous rating of any remaining transmission facility should not be exceeded. Any new facilities connected to the transmission system should not significantly decrement FCITC's for transfers between utilities. *Any addition of a transmission interconnection to the Company shall meet the Company's Planning standards as stated in Exhibit A of this document.*

3.3. System Stability

A stability study is required for all proposed generating units to be connected with the Company's transmission system. NERC Reliability StandardsTPL-001-0 through TPL-004-0 (System Performance under Normal and Emergency Conditions) describe various requirements and are summarized in Table I included with those standards. Verification of generating unit real and reactive capabilities are covered under NERC Reliability Standards MOD-024-1 and MOD-025-1. The Company has accepted these NERC Reliability Standards, and the follow-up measures defined by SERC, as minimum requirements.

3.4. System Protection – Transmission Lines

Operating voltage and proximity to a generating unit will be major considerations in the selection of the basic type of primary and backup relay units that will be required for protecting a transmission line that connects to the Company's transmission grid. These considerations, in conjunction with the particular stability classification (critical or non-critical) determined during the Facility Tests, will determine the extent to which backup coverage is to be incorporated in a transmission line's protection scheme. Protection requirements for protecting lines classified as critical and non-critical are covered in the General Requirements section of this document.

All fault interrupting devices selected by the customer must be reviewed and approved by Dominion for each interconnection point. In order to maintain Transmission reliability, each fault-interrupting device must be rated for full fault interrupting capability to satisfy the short circuit level requirements at the point of interconnection. Full fault

interrupting capability is per the latest IEEE guidelines. As a general rule, neither party should depend on the other for the protection of their respective equipment.

3.5. Communications - Transmission

PJM is the Transmission Provider and Market Operator for the Dominion zone. Transmission service and energy scheduling are arranged between the customer and PJM by using the PJM eSuite applications.

- SECTION 4 -

GENERATOR CONNECTION REQUIREMENTS

The same factors used to evaluate the connection of (1) another transmission facility and (2) customer load to the Company's transmission system must also be considered when new or additional generation capacity is to be connected to the transmission system. In addition to those operating conditions analyzed for an addition of load to the Company's transmission system as discussed in Section 3, analysis of the transmission system during and after transmission system faults are essential for the addition of generation on the Company's transmission system.

The Company will interconnect new generating facilities and increases in the capacity of existing generation already connected to Dominion's transmission system pursuant to the terms of the PJM Open Access Transmission Tariff and the conditions outlined in PJM Manual 14 Series. The evaluation of these factors also requires a power system analysis of the Dominion Transmission Network under several different operating conditions:

- Normal operations (both peak and off peak)
    - NERC Reliability Criteria also requires that critical system conditions be analyzed. Critical System conditions can include the loss of the largest generating unit in the area being studied and can also include the analysis and impacts associated with local generators operating at their maximum capability (Pmax) in the local area being studied.
- Compliance with NERC Reliability Criteria (TPL-001, 002, 003, 004)
- Operations during periods of power transfers for both import and exports as noted in Exhibit A.

The determination of new transmission interconnection requirements for generation capacity additions must consider the same factors as those considered in the Section 2 and Exhibit A of this document.

4.1. Supervisory Control and Data Acquisition - Generation

Prior to any operation of a Generator Facility, a RTU or equivalent data collection and transfer equipment acceptable to both the Customer and the Company shall be installed by the Generator, or the Company at the Generator's expense, to gather accumulated and instantaneous data to be telemetered to a location(s) designated by the Company through use of a dedicated point-to-point data circuit(s). The communication protocol for this data circuit(s) shall be specified by the Company. Instantaneous voltage data plus bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by the Company.

The Generator will provide standard voice and facsimile communications at its Facility control room through use of the public telephone system. The Generator will also provide a 4-wire, full duplex data circuit (or circuits) operating at 1200 baud, or at other baud rates as reasonably specified by the Company. The data circuit(s) shall extend from Generator's Facility to a location(s) specified by the Company.
Typical data requirements include the following:

- Status of interrupting devices
- MW flow
- MVAR flow
- Voltage at interconnection point
- Voltage and MVAR at generator leads

4.2. Telemetering and Metering - Generation

In addition to the General Requirements stated in Section 2.5. of this document, the Generator shall also provide at its expense an extension of the Company's System Operations Center's PBX system in the control room of the Eligible Customer and equipment for purposes of generation scheduling and/or coordination of switching.

4.3. System Protection - Generation

The type, size, and location of the generation will determine the specific requirements. The intent of the requirements is to promote the safe and reliable operation of the Company's electrical system. There are many individual steps required to assess the viability of a given generation interconnection request.

These requirements apply to generation facilities that connect directly to the transmission system through their GSU and/or generator breaker. In addition to the review of the transmission connection, circuit protection requirements will include the interconnect protection scheme and the possibility of transfer trip logic. Since the size and variety of generation interconnections are so varied, each proposed protection scheme will be reviewed under its specific conditions on a case by case basis. *Generator protection will generally follow the requirements of the latest revision of ANSI C37.102.*

The developer will own the Generator Step-up (GSU) transformer and will be responsible for synchronizing its facility to the Company's electrical system.

4.4. Islanding

Should the generator connect to a transmission line having other tapped load, there will be an additional requirement to prevent islanding. For the purpose of this document, islanding is defined as a generator being isolated such that it is the only source of power to a utility customer. This condition will be prevented via the use of an automatic trip (normally a transfer trip via carrier) from the utility to the generator in the event that the generator and the tap load are isolated from the rest of the system.

4.5. Transmission Line Connections

4.5.1 Single Circuit Interconnections to a Transmission Line

A transmission line tap as shown in Figure 6 can generally be used to interconnect a proposed new generating facility of any size located within one mile, or a generating facility of 500 MW or less located at a distance greater than

one mile to the transmission system. With this arrangement, loss of generation does not interrupt flow on the transmission system and loss of a transmission line does not result in loss of generation. Because of the close proximity, customer owned GSU transformer relay protection can potentially be used to direct trip Dominion's feeder breakers for the purpose of clearing a fault on the customer's equipment. Final System Protection requirements and interconnection substation requirements are based on the results of the PJM Interconnection Queue process as defined in PJM Manual 14 Series (http://www.pjm.com/~/media/documents/manuals/m14a.ashx). The customer should reserve property for construction of the Dominion owned interconnect station.

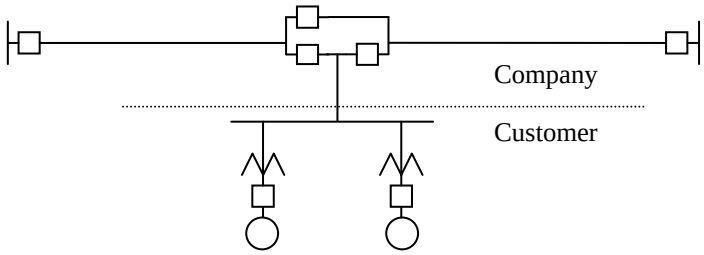

Figure 6: Line Tap – Generation Adjacent to Transmission Line

4.5.2 Transmission Interconnections Located Remote from a Transmission Line

If the proposed Generating Facility is greater than 500 MW and located more than one mile from an existing transmission line then the proposed arrangement shown in Figure 7 or 8 may potentially be used. With this arrangement, loss of generation does not interrupt flow on the transmission system and loss of a transmission line does not result in loss of generation. Final System Protection requirements and interconnection substation requirements are based on the results of the PJM Interconnection Queue process as defined in PJM Manual 14 Series (http://www.pjm.com/~/media/documents/manuals/m14a.ashx). The customer should reserve property for construction of the Dominion owned interconnection station.

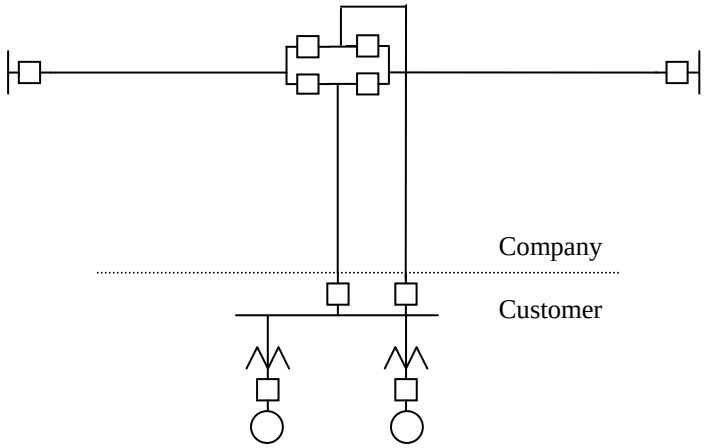

Figure 7: Line Tap – Large Generation located Remote from Transmission Line

As an alternative to constructing a switching station at the tap point, the transmission line can be cut and looped in and out to a switching station located adjacent to the generating station as shown in figure 8. This arrangement can have its advantages since acquiring land and permitting a new station at the tap point would not be required. Other advantages include no requirement for a customer owned interconnect breaker as well as simplifying several protection and communication interface requirements between the plant and the interconnect site. Because of the close proximity, customer owned GSU transformer relay protection can direct trip Dominion's feeder breakers for the purpose of clearing a fault on the customer's equipment. The customer should reserve property for construction of the Dominion owned interconnection station.

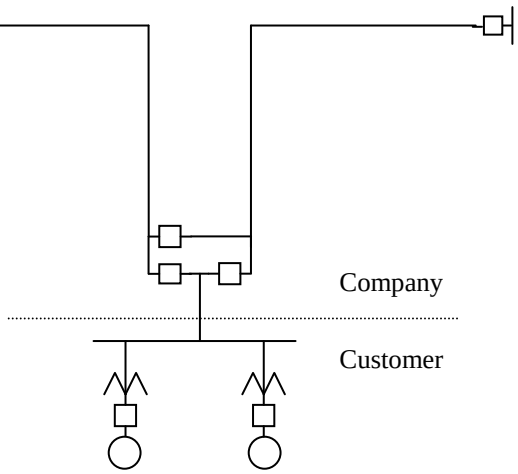

Figure 8: Looped Tap – Large Generation located Remote from Transmission Line

4.5.3. Substation Interconnection Requirements

All generation interconnection substation designs will include all switches and devices required to permit maintenance of all breakers and transmission lines without the loss of the ability to use the generation capacity when required. Small units can be bussed together behind breakers unless reliability studies indicate issues.

4.5.4. Transmission Interconnection Breakers

If new transmission lines are required by the addition of generator capacity at a new or existing power station, the breaker arrangement at the existing substation will determine both the number of breakers and the breaker arrangement required for the interconnection. Line terminations that result in a six breaker or less ring bus are acceptable. If more than a six breaker ring bus is required, a breaker and a half arrangement would be used for reliability considerations.

4.5.5. Generation Interconnection Breakers

A customer owned interconnection breaker is required if the generating station is located remote from the interconnection station (See Figure 7). Small generating units totaling 500 MW or less, or all units of a combined-cycle set can be bused

together behind this breaker as shown in Figure 9 or multiple breakers can be used as in Figure 10.

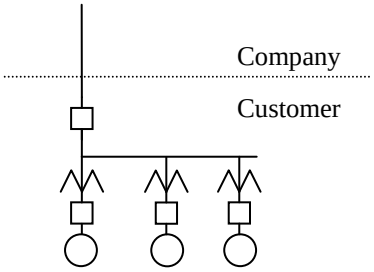

Figure 9

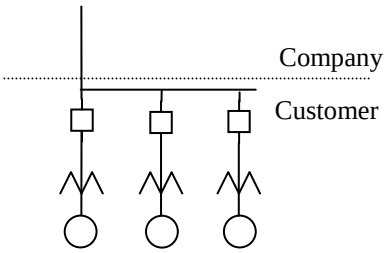

Figure 10

4.6. System Stability

The Generator shall operate its Facility(ies) with the appropriate safeguards and stabilization systems and other protective equipment necessary to protect and prevent damage to the Company's Transmission System, including operating the Facility generator unit with its speed governors and voltage regulators in service at all times. Should automatic functions not be available or should they fail to operate, including any voltage regulator, the Generator shall immediately notify the Company. The Generator shall repair these same systems as quickly as it is reasonably possible to do so, dependent upon the availability of replacement systems or parts and the stability of the Company's Transmission System. The Generator shall accept any operating restrictions necessary during the outage of automatic function of such equipment. The Generator shall be responsible to protect its own facilities against instability resulting from disturbances on The Company's Transmission System.

A stability analysis is required for all proposed generating units to be connected with the Company's transmission system as well as for an increase in the existing units' capability. Such requests must be submitted to PJM according to their Generation Interconnection (GI) process (details at www.pjm.com). The data requirements for generation equipment (generator, excitation system, turbine-governor, power system stabilizer, etc.) are specified in NERC Reliability Standards MOD-010-0 through MOD-

015-0. PJM can provide the detailed data sheets as part of their GI process. The NERC Reliability Standards TPL-001-0 through TPL-004-0 (System Performance under Normal and Emergency Conditions) describe various requirements and are summarized in Table I included with those standards. Verification of generating unit real and reactive capabilities are covered under NERC Reliability Standards MOD-024-1 and MOD-025-1. The Company has accepted these NERC Reliability Standards, and the follow-up measures defined by SERC, as minimum requirements.

Dominion may require a generator owner to install a Power System Stabilizer (PSS) on the generating unit(s) if stability studies or actual operating experience show a need anytime during the life of the facility. It is the Interconnecting Customer's responsibility, at their expense, to install, tune and commission the PSS. Dominion shall have the right to revise settings proposed by the generator if necessary.

It is the generator owners responsibility to perform required tests to verify various generating equipment models an data as required by NERC Reliability Standards.

The requirement for reactive power and generation equipment data are described in detail in PJM's Open Access Transmission Tariff (OATT) filed with the Energy Regulatory Commission (FERC).

4.7. Generation Controls

All generators connected to the Company system operate in automatic voltage regulation; power factor control is not a requirement on the Company system. A generator voltage regulator is required to be in service and in automatic mode whenever the generator is synchronized to the system. Unless otherwise directed by the Company's Operations center, the automatic voltage regulator shall control the voltage output within the reactive capabilities of the generator to maintain the nominal voltage of the connected transmission system.

To satisfy NERC Reliability Standard VAR-002-1, the Company requires all generator owners/operators to keep detailed records as to when each on-line generating unit does not operate in the automatic voltage control mode. The generator owner/operator shall be responsible for providing detailed reports and summary report for a specified time period when requested by Dominion Virginia Power, the respective NERC region or NERC (within 30 business days of the request).

A speed governor system is required on all generators to regulate the output of the generator as a function of the system frequency. The speed governor system must respond to system frequency changes to help maintain the stability of the power system. The speed governor system shall have a speed regulation (droop) characteristic settable between three and seven percent and typically set to five percent.

The Company shall have the right to temporarily disconnect, without notice, the Interconnection Facilities from the Company system if, in the Company's opinion, a hazardous condition exists and such disconnection appears reasonably necessary to protect the Company's customers, employees, agents, or property. The Company shall use its best efforts to reconnect with the Interconnection Facilities as soon as reasonably possible after it has determined that the hazardous condition no longer exists.

The Company, with reasonable notice to the Customer, shall not be obligated to accept, and may require the Customer to temporarily curtail, interrupt, or reduce deliveries of Net Electrical Output, or Net Electrical Output and Dependable Capacity when it is necessary for the Company to construct, install, maintain, repair, replace, remove, investigate, inspect, or test any part of the Interconnection Facilities or any of the Company's Interconnection Facilities, equipment, or any other relevant part of the Company's system. The Parties will coordinate such activities to limit the adverse impact on each other.

Generator's interconnecting with the Company's transmission system are required to meet all applicable NERC Reliability Standards that apply to generation owners.

4.8. Communications – Generators

At the Generator's expense, the Generator shall maintain satisfactory operating communications with the Company's system operator or representative, as designated by the Company. The Generator shall provide standard voice line, dedicated voice line and facsimile communications at its Facility control room through use of the public telephone system. The Generator shall also provide the dedicated data circuit(s) necessary to provide necessary generator data to the Company. The data circuit(s) shall extend from the Generator Facility to a location(s) specified by the Company. Any required maintenance of such communications equipment shall be performed at Generator's expense, but may be performed by Generator or by the Company.

4.9. Obligation to Supply Reactive Power

Generator facilities connecting directly to the Transmission System at 69 kV or higher voltages will comply with NERC Reliability Standard VAR-002-1 with regard to voltage support and supply of reactive power to the Transmission System. All generator facilities connecting to the Transmission System at 69 kV or higher voltages shall operate in automatic voltage regulation. A generator voltage regulator is required to be in service and in automatic mode whenever the generator is synchronized to the Company's Transmission System. Unless otherwise directed by the Company, the automatic voltage regulator shall, within the reactive capabilities of the generator, control the voltage output pursuant to the voltage schedule prescribed by the Company. The Company shall have the right to alter the voltage schedule as the system operating conditions may require from time to time. Also Generator Facilities have requirements to supply reactive power which are based on the PJM Tariff which is defined in PJM Manual 14 Series (http://www.pjm.com/~/media/documents/manuals/m14a.ashx)

When the Company declares an Emergency Condition on its Transmission System or on an adjacent transmission system, the Company shall have the authority to direct the

Generator to increase or decrease real power production (measured in MW) and/or reactive power production (measured in MVAR), within the design and operational limitations of the Facility equipment in service at the time, in order to maintain Transmission System security. In the event of a declaration of an Emergency Condition, a determination: (i) that the Transmission System security is in jeopardy, and (ii) that there is a need to increase or decrease reactive power production, even if real power production is adversely affected, will be made solely by the Company. The Facility operator will honor the Company's orders and directives concerning Facility real power and/or reactive power output within the design limitations of the Facility's equipment in service at the time, such that the security of the Company's Transmission System is maintained. The Company shall restore Transmission System conditions to normal as quickly as possible to alleviate any such Emergency Condition. The Company will take all reasonable steps to allocate among all generating units and other reactive power supply resources the responsibility to provide reactive power support to the Company's Transmission System.

4.9.1. Reactive Power – Generation

Generator shall supply reactive power to the Company's Transmission System or absorb reactive power from the Transmission System in accordance with Good Utility Practice, applicable operational and/or reliability criteria, protocols, and directives, including those of the Applicable Reliability Council and Applicable Laws and Regulations and this Agreement. Generator shall respond to requests from the Company to increase or decrease generator reactive power output in a manner consistent with Generator's obligation to operate and control the Facility. The Generator Facility shall supply or absorb such reactive power in accordance with the voltage schedule or reactive levels prescribed by the Company but not in excess of the amount available from the Facility's equipment in operation at the time and within the manufacturer's design limitations of the Facility. The Company's Transmission System Operator shall provide the voltage schedule to the generator owner/operator.

The Company requires the generators to meet the following design and operational requirements described in NERC Reliability Standard VAR-002-1 and its SERC Supplement :

Design requirements include:

- Internal plant systems design (e.g., transformer rating/taps/impedance, cooling systems, generator/exciter rating) should not limit continuous reactive capability.
- Transmission interconnected equipment should have the tap ranges and self-regulation necessary to accommodate the transmission system's reactive power flow requirements.
- Transmission interconnections should not have an impact on adjacent areas' reactive power flow requirements

Operational requirements include:

- Testing to verify reactive support capability per NERC Reliability Standards
- Generator step-up transformer (GSU) tap changes as necessary to meet voltage schedule and reactive support requirements

4.9.2. Network Schedule Voltage

All generators are expected to maintain the voltage schedule as required by the Company's Transmission System Operator within the reactive capability of the generating units. To satisfy NERC Reliability Standard VAR-002-1, the Company requires all generator owners/operators to keep detailed records of as to when each generating unit does not comply with the Transmission System Operator's schedule. The generator owner/operator shall be responsible for providing detailed reports on voltage deviations from the acceptable voltage ranges for a specified time period when requested by the Company, SERC or NERC (within 30 days of a request).

4.10. Maintenance - Generation

The Company shall have the right, but shall have no obligation or responsibility to

(i) observe Generator's tests and/or inspection of any of Generator's System Protection Facilities and other protective equipment,

(ii) review the settings of Generator's System Protection Facilities and other protective equipment, and

(iii) review Generator's maintenance records relative to the Facility, Generator Interconnection Facilities, and/or Generator's System Protection Facilities and other protective equipment.

The Company shall maintain its facilities and equipment, to the extent they might reasonably be expected to have an impact on the operation of the Facility(ies) in a safe and reliable manner, in accordance with Good Utility Practice and in accordance with the provisions of this document. The Generator shall maintain its facilities and equipment, to the extent they might reasonably be expected to have an impact on the operation of the Transmission System and the Company's other systems in a safe and reliable manner, in accordance with Good Utility Practice and in accordance with the provisions of this Agreement.

Maintenance requirements are also covered in the General Requirements section of this document.

4.11. Metering – Generation

At Generator's expense, the Company shall, in accordance with Good Utility Practice, specify, install, own, operate, and maintain all Metering Equipment for the Interconnection Points that measure energy flows on an hour-by-hour basis, or such shorter intervals as may be required by the Company. The Metering Equipment specified shall also allow the Company to have the capability to properly monitor generator imbalance conditions. The related equipment shall include instrument

transformers and any of the associated communications links needed. The information provided by the metering facilities shall meet the reasonable needs and approvals of all Parties, consistent with Good Utility Practice.

All Revenue Meters shall be of advanced meter design such that they have an internal recorder and communications capability that the Company can utilize to retrieve diagnostic messages, the recorded transfer of energy between the Parties, and any other information deemed necessary by the Company.

Metering Equipment shall be as follows:

- Each Facility connected to the Company‘s Transmission System, including Distribution Facilities, shall have Metering Equipment installed to provide direct readings of the Facility’s net bi-directional real and reactive power and energy output. The metering instrument transformers used to measure the Facility’s net output shall be installed on or compensated to the high side (transmission voltage side) of the generator step-up transformer, unless otherwise agreed by the Parties.

- All plant auxiliary power transformers (non-generator step-down transformers) and lines directly connected to the Company’s Transmission System, including Distribution Facilities, shall have Metering Equipment installed to provide bi-directional real and reactive power and energy flow. Metering instrument transformers shall be connected to or compensated to the high side (transmission voltage side) of the power transformer, unless otherwise agreed to by the Parties.

All Metering Equipment installed pursuant to this document shall be routinely tested by the Company in accordance with Good Utility Practice, and such results reported to Generator Owner. The Company, at the expense of the Generator, will test all Revenue Meters and analog equipment at least once every two years. The Generator may request any number of additional meter tests and will compensate The Company for the actual cost incurred to test such meters. If the Metering Equipment is found to be

inaccurate by more than one-third of one percent (0.3%) of full meter registration or are otherwise defective, they shall be repaired, adjusted, or replaced by The Company at the expense of the Generator. No adjustment shall be made for meter readings made prior to the point in time halfway between the time of the last test that showed the Revenue Meters and analog equipment in question to be functioning accurately and the time the subsequent inaccuracy is corrected, except by agreement of the Parties. In any case, all Revenue Meters and analog equipment shall be tested at least once every two (2) years.

Unless otherwise mutually agreed, all meters shall be sealed, and the seals shall be broken only by the Company upon occasions when the meters are to be inspected, tested, adjusted or re-calibrated in accordance with Good Utility Practice.

Metering requirements are also covered in the General Requirements section of this document.

4.12. Responsibilities During Emergency Situation – Generation

Each Party agrees to comply with RTO, NERC and SERC Emergency Condition procedures and the Company and Generator Owner Emergency Condition procedures, as applicable, with respect to Emergency Conditions.

The Company shall provide the Generator with notification that is prompt under the circumstances of an Emergency Condition that may reasonably be expected to affect the Generator's operation of the Facility, to the extent the Company is aware of the Emergency Condition. The Generator shall provide the Company with notification that is prompt under the circumstances of an Emergency Condition which may reasonably be expected to affect the Company’s Transmission System, to the extent the Generator is aware of the Emergency Condition. To the extent the Party becoming aware of an Emergency Condition is aware of the facts of the Emergency Condition, such notification shall describe the Emergency Condition, the extent of the damage or

deficiency, its anticipated duration, and the corrective action taken and/or to be taken, and shall be followed as soon as practicable with written notice.

In the event of an Emergency Condition, the Party becoming aware of the Emergency Condition may, in accordance with Good Utility Practice and using its reasonable judgment, take such action as is reasonable and necessary to prevent, avoid, or mitigate injury, danger, and loss. In the event the Generator has identified an Emergency Condition involving the Company's Transmission System, the Generator shall obtain the consent of the Company personnel prior to manually performing any switching operations unless, in the Generator's reasonable judgment, immediate action is required.

Facility may be called upon by the Company during a potential or actual Emergency Condition to mitigate such Emergency Condition by, but not limited to, requesting the Facility to start-up, shutdown, increase or decrease the output of the Facility.

Responsibilities during emergency situations are also covered in the General Requirements section of this document.

4.13. Inspection Requirements – Generation

The Generator shall grant the Company right of access to their facility for purposes of conducting inspections, observing tests, and auditing records required by NERC standards and established reporting procedures. Inspection requirements are also covered in the General Requirements section of this document.

Each Party shall perform routine inspection and testing of its facilities and equipment, including secondary low voltage control systems, in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Facility with the Company's Transmission System in a safe and reliable manner. Each Party shall, at its own expense, have the right to observe the testing of any of the other Party's facilities and equipment whose performance may reasonably be expected to

affect the reliability of the observing Party's facilities and equipment. Each Party shall notify the other Party in advance of its performance of tests of its facilities and equipment, and the other Party may have a representative attend and be present during such testing.

If a Party observes any deficiencies or defects on, or becomes aware of a lack of scheduled maintenance and testing with respect to, the other Party's facilities and equipment that might reasonably be expected to adversely affect the observing Party's facilities and equipment, the observing Party shall provide notice to the other Party that is prompt under the circumstance, and the other Party shall make any corrections required in accordance with Good Utility Practice.

- SECTION 5 -

ELECTRICITY END-USER CONNECTION REQUIREMENTS

5.1. Load Guidelines

Transmission facilities may be used for providing service to commercial, industrial, municipal, cooperative and cogeneration customers when the use of distribution feeders is not practicable. Generally, the use of transmission facilities should be considered for the following conditions:

- All loads and generation over 20 MVA
- Locations remote from distribution facilities
- Remote locations where distribution facilities are not adequate
- Loads with nonstandard voltage requirements
- Loads having large surge requirements

The feasibility of serving customers direct from transmission requires a comprehensive study and coordination. Factors to be considered prior to agreeing on a customer connection is as follows:

- Economics of alternates
- Customer parallel generation
- Transmission line tap or loop length
- Customer transformer characteristics
- Customer switching
- Effect on protective relaying at remote terminals
- Problems of large through power on looped lines
- Extent of customer facilities

The following diagrams indicate the facilities arrangement for normal service 100 kV and above.

5.1.1. Tapping Line Below 100 MW Demand

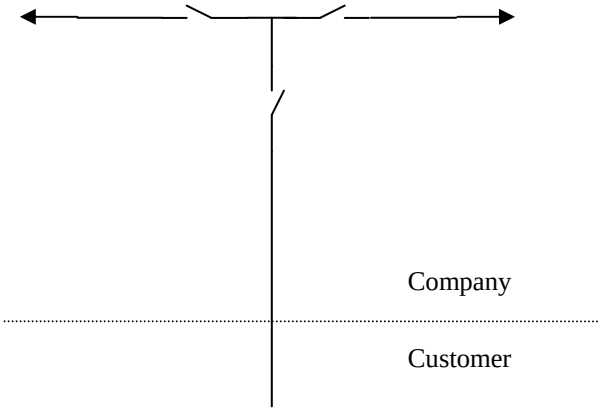

Figure 11: Tapping Line Below 100 MW Demand

In general, a tap line in excess of a mile will require a circuit breaker for protection. If the tap line is long enough to require a circuit breaker, a single breaker with an airbreak switch bypass will be considered for 138 kV or below. Above 138 kV, two breakers in parallel or a three-breaker ring will be used. If a breaker is required at the customer's facilities, the customer provides the breaker. The company will not allow a bypass switch on transformer highside interrupting devices connecting directly to the transmission line.

Where two circuits are available, a preferred-alternate scheme may be applied. The Company will conduct a review and determine the need for equipping switches with vacuum attachments for breaking parallel or line charging currents. In general, all 230 kV switches require vacuum attachments to perform these

functions and 115 kV and 138 kV switches are judged on a case by case basis depending on load and recovery voltage.

The following are preferred minimum demands for tapping existing transmission lines:

500 kV – Reserved for bulk power transfers
230 kV – 30 MW
138 kV – 20 MW
115 kV – 20 MW

5.1.2. Tapping Line 100 MW Demand and Above

The addition of customer load in access of 100 MW's should be connected to the Company's transmission system as shown in Figure 12 below.

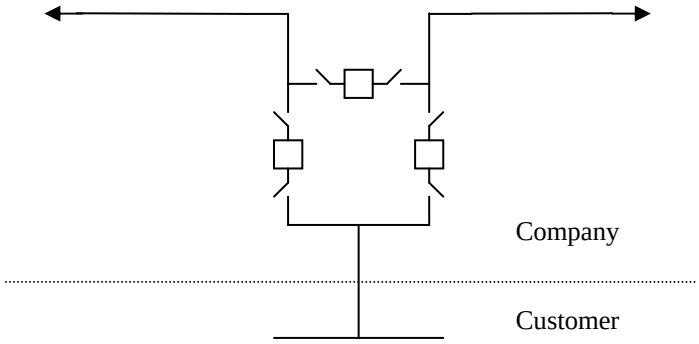

Figure 12: Tapping Line 100 MW Demand and Above

5.1.3. Tapping Company's Bus

In those cases where it may be practicable to tap an existing transmission substation bus to serve a customer, the following diagrams indicate the facilities arrangement for normal service:

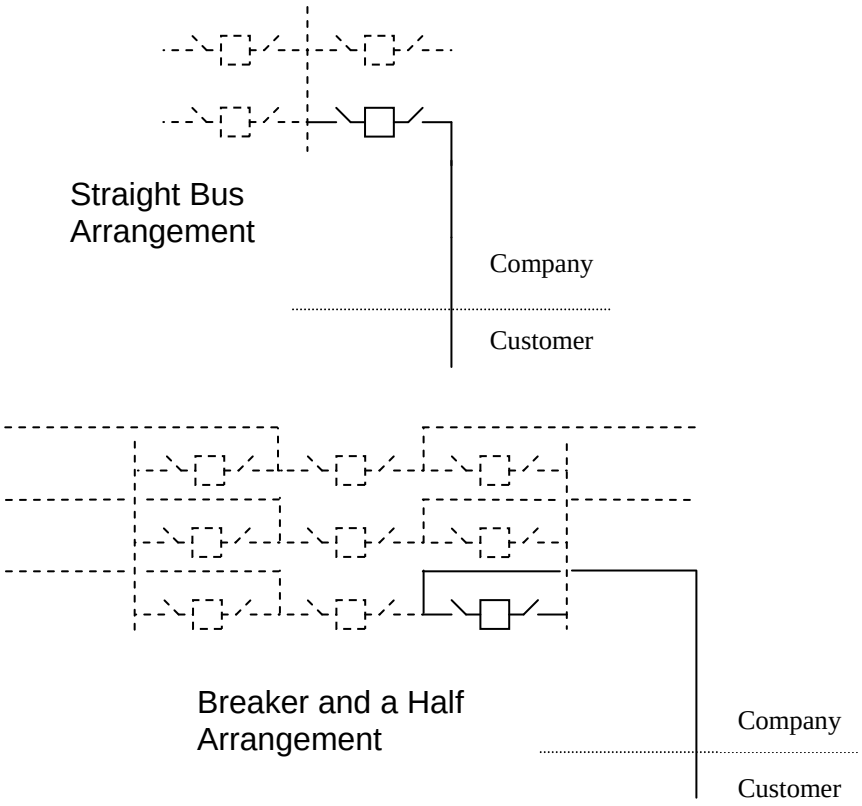

Figure 13: Tapping Existing Substation Bus
Below 100 MW Demand

The following are preferred minimum demands for tapping existing substation busses:

230 kV – 75 MW

138 kV – 50 MW

115 kV – 50 MW

For situations where demands are less than the above, but a circuit breaker is required due to a long Company transmission line to the delivery point, a breaker may be connected to the substation bus instead of the line. Existing substation busses may be tapped at two places with two breakers provided by the Company for 100 MW Demand or more.

5.2. Power Quality – End User

Power Quality requirements for end-user customers are covered in the General Requirements section of this document.

5.3. Reactive Power Requirements – End User

Unless otherwise agreed, the Transmission Load Customer is required to maintain a power factor within the same range as the Company pursuant to Good Utility Practices. The transmission customer shall maintain a minimum power factor of 97.3% (lagging) at transmission level delivery points or as specified in the Service Agreement where applicable. Details regarding reactive power for generators are included in the Generator Connection Requirements section of this document.

5.4. Stability Studies

If an industrial customer has internal generation a stability study may be required. The customer must supply a detailed description of the customer's load characteristics, internal distribution system representation, generating equipment models and data, etc. The customer will reimburse any and all expenses incurred by the Company in performing such a study.

5.5. System Protection and Other Controls

The end user is responsible for providing a protection system that will protect its equipment against disturbances on the Company's system and minimize the effects of disturbances from its facilities on the Company's equipment and transmission system.

The latest IEEE C37 and C57 guides and standards for protective relaying systems should be followed.

All fault interrupting devices selected by the customer must be reviewed and approved by Dominion for each interconnection point. In order to maintain Transmission reliability, each fault-interrupting device must be rated for full fault interrupting capability to satisfy the short circuit level requirements at the point of interconnection. Full fault interrupting capability is per the latest IEEE guidelines. As a general rule, neither party should depend on the other for the protection of their respective equipment.

5.6. Communications - End-User

The Company has established a Key Customer Accounts department for its major end-use customers. The Key Customer Accounts Department shall closely monitor local sources for incoming information and will communicate to key customers. The Account Managers in the Key Customer Accounts maintain communication with major end-use customers during normal situations by mail, telephones, e-mails, seminars, brochures, etc. as appropriate. The Company's Customer Service Centers are available 24 hours a day to all customers via toll free numbers. In an emergency situation, the Company's System Operation Center will initiate communications with internal operating entities, Key Customer Accounts, Customer Service Centers, Corporate Communications and the Security Control Center. The Security Control Center shall call representatives of the various Company groups to alert them of the emergency and have them report for duty. Corporate Communications shall supply news releases to the media for general broadcast. The Customer Service Centers will call specific Key Customers to inform them of the situation and ask them for assistance as needed. The Key Customer Accounts department provides to the Customer Service Center a list of Key Customers to be called. Also, the Key Customer Accounts group is available for customers on the list to contact them for additional information.

EXHIBIT A

PLANNING GUIDELINES

GENERAL CRITERIA

The Company endeavors to maintain a high degree of reliability in electric service that satisfies the average customer's service requirements at a reasonable cost.

The North American Electric Reliability Corporation (NERC), and the eight (8) regional reliability councils, have developed mandatory, enforceable NERC Reliability Standards which must be complied with to assure reliable service to all areas of the United States. Additional criteria may be needed within an operating system to satisfy requirements specific to that area.

The Company is a member of the SERC Reliability Corporation (SERC) and is guided by the criteria set forth by that council. In addition, the following criteria are used in planning the Company's transmission system. These criteria apply to conditions of expected firm power transfers among the Company and its neighboring power systems and to the official company load forecasts, which are based on "normal" weather and projected, prevailing economic conditions.

As with generating capacity, reserve capacity must also be provided in the transmission system to recognize the effects of deviations from normal weather, load forecast uncertainty and variations in day to day operating conditions. In the application of the following criteria an allowance of 6% should be made in transmission facility loading (lines and transformers).

- Under normal loading conditions (All transmission facilities in service) no transmission facility should be loaded greater than its normal rating.

- The loss of any one transmission circuit should not cause the emergency rating(8 hour) to be exceeded on any of the remaining transmission facilities nor should it cause the loss of any load, other than the load connected to that circuit, and the resultant voltage at any location on the 115 kV and 138 kV transmission system should not drop below 0.93 P.U. after transformer load tap changing equipment has readjusted nor should it drop below 0.93 P.U. on the 230 kV system and 1.01 P.U. on the 500 kV system.

- The loss of any two transmission circuits on a common right-of-way should not result in cascading outages or loss of load, other than that connected to the two circuits, and the resultant voltage at any location on the transmission system should not drop below 0.92 P.U. after transformer load tap changing equipment has readjusted nor should any overhead transmission facility be loaded to more than 30% above its emergency rating(8 hour) during the period required to make prompt power supply adjustments to reduce overload to less than or equal to its emergency rating. Power supply adjustments can include loss of load (consequential and non-consequential) provided it does not exceed 300 MW.

- The transmission system should be capable of supplying peak loads without exceeding the emergency rating(8 hour rating) on any facility for the following:

    1. The outage of the two largest generators in any generating station when all transmission facilities are in service.
    2. Critical System Conditions (The outage of the largest generator in any generating station which has the greatest effect on the transmission facilities being studied.) and the loss of any transmission facility.

During the above generation outages, other Company generating sources would be adjusted to make up the deficiency to the limit of available capacity.

- Stability requirements described in Table I of NERC Reliability Standards TPL-001-0 through TPL-004-0 must be met, at a minimum.

- The loss of three or more transmission circuits on a common right-of-way should not result in cascading outages beyond the load area immediately involved. The overall supply system to a major load area should be able to withstand the loss of all circuits on a common right-of-way and still supply most of the load in the area with tolerable voltage (at least 90% of nominal). A major load area would be an area similar to the Norfolk/Virginia Beach area or the Northern Virginia area.

- The loss of all generation at a generating station should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than 30% above its emergency rating(8 hour) during the period required to make prompt power supply adjustments to reduce overloads to less than or equal to its emergency rating. Power supply adjustments can include loss of load (consequential and non-consequential) provided it does not exceed 300 MW.

- The loss of a generating station substation, switching station or load substation should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than 30% above its emergency rating(8 hour) during the period required to make prompt power supply adjustments to reduce overloads to less than or equal to its emergency rating. Power supply adjustments can include loss of load (consequential and non-consequential) provided it does not exceed 300 MW.

- The outage of a critical transmission facility, which occurs while another critical transmission facility is already out of service, should not result in cascading outages or intolerably low voltage (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than 30% above its emergency rating(8 hour) during the period required to make prompt power supply adjustments

to reduce overloads to less than or equal to its emergency rating. Power supply adjustments can include loss of load (consequential and non-consequential) provided it does not exceed 300 MW.

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- The transmission system should be capable of transferring reasonable amounts of power, in excess of firm purchases, sales and transfers, between and among the Company and the neighboring utilities with all transmission facilities in service or with one transmission circuit or transformer out of service and not exceed the maximum continuous rating of any remaining transmission facility. Any new facilities connected to the transmission system (greater than 20 MW) should not significantly decrement (greater than 5%) FCITC's for transfers between utilities.

- Combustion turbine generators should not be used for more than seven days to provide adequate service during the outage of a line or transformer. The assumed availability of combustion turbine generator units at any one time shall be in accordance with the following guide:

Number of Units At The Location	Number Available At Any One Time
2	1
3	2 smallest
4	3 smallest
5	3 smallest
6	4 smallest
Above 6	70% of Total Capacity

- Load on transmission radial lines without alternate supply should be limited to approximately 100 MW. A key factor in evaluating the load limitation on a radial transmission line is the distribution load that can be switched to circuits served from other sources. Unlike load served from a networked transmission line where a downed conductor or structure can be sectionalized allowing the remainder of the line to be reenergized before repairs are completed, load served from a radial transmission line can not be reenergized until all repairs to the line are completed.

Other factors include being able to perform maintenance on the radial line, outage history of line, load density and type, tie capability, etc.

- The transmission system must be examined frequently to assure that an effectively grounded system is maintained. A bus is considered to be "effectively grounded" when the following relationships are true:
  - $X_o/X_1 \leq 3$
  - $R_o/X_1 \leq 1$

This relationship assumes $R_1/X_1 = 0$, which is a worst case condition. If one or both of these relationships are not true, the effective grounding should be checked more precisely by referring to the curves found in the "*ABB Electrical Transmission and Distribution Reference Book*". The curves can be found in Chapter 18, page 626. The proper curve to use should be based on the actual R_1/X_1 ratio. Any set of ratios lying below the appropriate curve marked 80% will provide effective grounding for 80% lightning arresters standardly used on the Dominion system.

Customer Request Form

Exhibit B

REQUEST/NOTIFICATION FOR CHANGES IMPACTING DOMINION'S FACILITIES

Customer shall initiate requests to install, modify, or remove Dominion Facilities, or to modify the capacity or characteristics required at a Delivery Point, or to discontinue the delivery of electricity to a Delivery Point, in writing using the Request/Notification for Changes Impacting Dominion Facilities form included in this Appendix A (the "Request Form"). Customer shall also submit a Request Form when making changes to Customer's Facilities that are reasonably anticipated to (i) lead to a modification to Dominion's Facilities or (ii) impact the operation of Dominion's Facilities.

The Request Form shall be submitted by Customer as soon as useful information is available. As additional or updated information becomes available, Customer shall make timely submission of a revised Request Form. For Request Forms submitted with notations of "(E)" or "TBD by *[date]*" as described below, the Parties shall determine a schedule for the provision of complete and final information.

1. Customer shall, in accordance with the following requirements, provide, on a timely basis, information that is complete and accurate. On every Request Form submitted, each blank (including items such as "Additional Comments" and "Other Milestones") shall contain one of the following entries:

    1.1. The firm (e.g., final) information.
    1.2. If no information is appropriate for a given item, the entry "N/A."
    1.3. An entry as further described below:
        1.3.1. In Sections II, III, and IV, an entry initially marked as "(E)." Such entries shall be revised with firm information as soon as it is available. If the "Requested Date to Energize" in Section IV is initially marked as (E), then the firm date ultimately supplied for "Requested Date to Energize" shall be on or after the estimated date unless an earlier firm date for "Requested Date to Energize" is mutually agreed-upon prior to submission of a revised request form.
        1.3.2. In Section III, an entry may be "TBD by *[date].*" Additionally, each of the Required Attachments of Section III shall be provided, or shall be substituted by a page bearing the attachment description and the date by which the attachment shall be provided.

2. Upon receiving a request, Dominion shall evaluate such request within its ordinary course of business and consistent with the PJM Requirements. The evaluation may include the investigation of alternate solutions to accommodating Customer's needs. Customer to reasonably assist Dominion's evaluation, including, without limitation, the provision of additional information and participation in a cooperative review and exploration of the request and its alternatives. Dominion shall not be required to complete such evaluation until a reasonable time after the Customer has supplied all information as firm information.

3. Upon concluding its evaluation, Dominion shall provide a written response approving the request, approving the request with modifications, or denying the request. Any modification or denial shall not be unreasonable and shall be accompanied by the reasoning for such determination. In the event of approval or modified approval, the response shall describe, consistent with the Agreement, any required construction or modifications by the Parties, any estimated Project costs, cost responsibilities between the Parties, and other actions the Parties must take to implement the request in its approved form.

REQUEST/NOTIFICATION FOR
CHANGES IMPACTING DOMINION FACILITIES

SECTION I – GENERAL Date: / / 20 Revision No.:

Requestor Name: _____

Requestor Address: _____

_____

Name of Contact Person: _____

Contact's Phone: - - ext. _____ Contact's Cell: - - _____

Contact's Fax: - - _____ Contact's Email: _____

Signature below authorizes Dominion to proceed with design, engineering, and estimation of Project cost as appropriate for Dominion to evaluate and respond to this request. This authorization is pursuant and subject to all terms and conditions of the Agreement of which this Appendix is a part.

Authorizing Signature: _____ Auth. Date: / / 20

Printed Name: _____ Phone: - -

Title: _____

SECTION II – DESCRIPTION OF REQUEST

Name of Delivery Point: _____

Brief Description of Request:
(attach detail) _____

Brief Reasoning for Request:
(attach detail) _____

Delivery Point Location:
(attach detail if DP is new) _____

Noteworthy Load Characteristics:
(large motors, large fluctuating loads, large harmonic-producing loads, etc.) _____

PRESENT DELIVERY POINT DATA:

Present Delivery Point Voltage: _____

Present Maximum kVA Capacity of Delivery Point Facilities: _____

Present Summer Peak kW Demand: _____ Present Summer Peak kVAR Demand: _____

Present Winter Peak kW Demand: _____ Present Winter Peak kVAR Demand: _____

ANTICIPATED NEW DELIVERY POINT FACILITES DATA:

New Delivery Point Voltage: _____

New Peak kVA Capacity of Delivery Point Facilities: _____

Peak kW and rkVA During First Three Years Following Implementation and Highest Peak Within Ten Years:

	Initial Year:	Second Year:	Third Year:	Highest in First Ten Years:
Enter Year ➔				
Summer Peak kW:				
Summer Peak rkVA:				
Winter Peak kW:				
Winter Peak rkVA:				

Delivery Point Facilities Route:
(attach detail if new line extension is involved) _____

Additional Comments: _____

SECTION III – CUSTOMER'S EQUIPMENT

Transformer Primary Voltage: _____ Transformer Secondary Voltage: _____

Transformer Nameplate Capacity: _____ Temperature Rise: _____

Transformer Taps: _____

Connection (e.g. Wye-Wye): _____

Transformer Impedance: _____

Isolation Device Type and Rating: _____

Protection Device Type and Rating: _____

Required Attachments: [1] One-line diagram [2] Transformer test report [3] Transformer loss curve
[4] Operating procedures description [5] Protection scheme functional diagram
[6] Protection Device information (including device types, serial and model numbers, relay settings, etc.)

SECTION IV – TIMING

Request included in Customer's planning documents submitted to Dominion on:

Most Recent Submission: / / 20 Second Most Recent Submission: / / 20

Expected Date Customer's Construction to Commence: / / 20

Expected Completion Date of Customer Work: / / 20

Date Requested for Dominion Construction to Commence: / / 20

Requested Completion Date of Dominion Work (De-energized): / / 20

Requested Date to Energize: **(See Note)** / / 20

Other Milestones: _____

NOTE: If the "Requested Date to Energize" is marked as (E), then the firm date ultimately supplied must be on or after the estimated date, unless an earlier firm date is mutually agreed-upon prior to submission of the revised request form.

(E) = Estimated

N/A = Not Available

TBD = To Be Determined

EXHIBIT C

DEFINITIONS and ABBREVIATIONS

C.1. Definitions

Wherever used in this document with initial capitalization, the following terms shall have the meanings as specified below. Terms used in this document with initial capitalization not defined shall have the meanings specified in The Company's Open Access Transmission Tariff.

Capacity

The seasonal maximum generating capability of the Facility, measured in megawatts.

Distribution Facilities

The facilities rated at less than 69 kV which are owned and operated by The Company and which are necessary to connect the Facility to the Transmission System.

Emergency Condition(s)

A condition or situation (i) that in the judgment of either Party is imminently likely to endanger life or property; (ii) that in the sole judgment of The Company is imminently likely to affect adversely or impair the Transmission System or imminently will affect or impair the transmission systems of others to which the Transmission System is directly or indirectly connected; or (iii) that in the sole judgment of the Generator Owner is imminently likely to adversely affect or impair the Facility. Such

a condition or situation includes, but is not limited to, overloading, or potential overloading of, excessive voltage drop, or other unusual operating conditions on the Transmission System or the Generator Owner's Facility such that the output of the Facility must be shutdown or curtailed to avoid damaging the Facility or the Transmission System.

Facility(ies)

The generator unit(s) and the equipment related to the operation of the unit(s) and the Interconnection Facilities on the Generator Owner's side of the Interconnection Point.

Good Utility Practice

Any of the applicable practices, methods, standards, guides or acts: required by any Governmental Authority, regional or national reliability council, or national trade organization, including NERC, SERC, or the successor of any of them, as they may be amended from time to time whether or not the Party whose conduct is at issue is a member thereof; otherwise engaged in or approved by a significant portion of the electric utility industry during the relevant time period which in the exercise of reasonable judgment in light of the facts known or that should have been known at the time a decision was made, could have been expected to accomplish the desired result in a manner consistent with law, regulation, good business practices, generation, transmission and distribution reliability, safety, environmental protection, economy and expediency. Good Utility Practice is intended to be acceptable practices, methods, or acts generally accepted in the region, or any other acts or practices as are reasonably necessary to maintain the reliability of the Transmission System, or of the Facility, and is not intended to be limited to the optimum practices, methods, or acts to the exclusion of all others.

Governmental Authority

Any federal, state, local or other governmental, regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, arbitrating body, or other governmental authority.

Interconnection Facilities

All structures, facilities, equipment, devices and apparatus owned or leased by, or under contract to either Party presently in place or proposed to be installed, which facilities are necessary to interconnect and deliver energy from the Facility(ies) to the Transmission System pursuant to the terms and conditions of a Generator Interconnection & Operating Agreement.

Interconnection Point

The point at which the Facilities are physically connected to the Transmission System (including any Distribution Facilities required to facilitate the interconnection).

Metering Equipment

All metering equipment currently installed at the Facility and/or any other metering equipment to be installed at the metering points designated in the Interconnection Facilities, including Revenue Meters.

RTO

A Regional Transmission Organization or any successor thereof which becomes responsible for operating the Company transmission system to which the Facility is connected.

Transmission System

The facilities owned, controlled and operated by Dominion Virginia Power/North Carolina Power that are used to provide transmission service, including any Distribution Facilities required to provide Wholesale Distribution Service, under the PJM OATT.

Wholesale Distribution Service

The provision of distribution service to wholesale customers, including generator facilities, over Distribution Facilities as necessary to effectuate transmission service under the PJM OATT or Interconnection Service under this Agreement.

C.2. Abbreviations

Wherever used in this document with initial capitalization, the following terms shall have the meanings as specified below. Terms used in this document with initial capitalization not defined shall have the meanings specified in the PJM Open Access Transmission Tariff.

AEP	American Electric and Power
ANSI	American National Standards Institute
ATC	Available Transfer Capability

EHV	Extra High Voltage
ERAG	Eastern Interconnection Reliability Assessment Group
FCITC	First Contingency Incremental Transfer Capability
GSU	Generator Step-up Transformer
IOC	Independent Operating Center
IEEE	Institute of Electrical and Electronic Engineers
MMWG	Multi-Regional Modeling Working Group
NERC	North American Electric Reliability Corporation
OATT	PJM Open Access Transmission Tariff
PCC	Point of Common Coupling
PSS	Power System Stabilizer
PSS/E	Power System Simulator for Engineers
PTI	Power Technologies, Inc.
RFC	Reliability First Corporation
SERC	SERC Reliability Corporation
SER	SERC East-RFC

THD	Total Harmonic Distortion
VACAR	Virginia-Carolina Sub-Region of SERC