Facility Connection Requirements

NERC Standard/Requirement#: FAC-001 (all requirements)

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Virginia Electric and Power Company - (DP, LSE, TO)
Electric Transmission

(d.b.a. Dominion Virginia Power)

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Level 1 - Public Information
Facility Connection Requirements

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EXHIBIT A - Virginia Power North Carolina Power Transmission Planning Criteria
EXHIBIT B - Customer Request Form
1. PURPOSE AND INTRODUCTION

This Virginia Electric and Power Company Facility Connection Requirements (FCR) document is publically available on the company’s web site “www.dom.com” to provide guidance to Interconnection Customers seeking to connect to its transmission system. It also serves as evidence that Virginia Electric and Power Company documents, maintains, and publishes facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements, as required by NERC Reliability Standard FAC-001.

Virginia Electric and Power Company is commonly referred to in Virginia as Dominion Virginia Power (DVP), and in North Carolina as Dominion North Carolina Power (DNCP). Virginia Electric and Power Company is referred to in this document as “Dominion” or “Company”.

1.1. Generation facilities

This document complies with FAC-001 R1.1 by addressing connection requirements for Generation facilities for each subrequirement of FAC-001 R3. (See Section 3 below for additional explanation)

1.2. Transmission facilities

This document complies with FAC-001 R1.2 by addressing connection requirements for Transmission facilities for each subrequirement of FAC-001 R3. (See Section 3 below for additional explanation)

1.3. End-user facilities

This document complies with FAC-001 R1.3 by addressing connection requirements for End-user facilities for each subrequirement of FAC-001 R3. (See Section 3 below for additional explanation)

The provisions of this document apply to Interconnection Customers seeking to connect to Dominion’s transmission system, except as may be otherwise provided for in applicable tariffs or agreements, or as may be otherwise agreed by Dominion and the Interconnection Customer.

Document structure. To simplify compliance reviews, this document is structured to align with the numbering scheme of NERC Reliability Standard FAC-001.

2. FAC-001 R2

2.1. FAC-001 R2 applies only to Generator Owner registration.
3. CONNECTION REQUIREMENTS PER NERC FAC-001 R3

This section identifies the requirements and subrequirements of NERC Reliability Standard FAC-001 R3. Each numbered item corresponds to the number of the R3 subrequirement. Unless otherwise noted, details under each numbered topic in this section apply globally to Generation facilities, Transmission facilities, and End-user facilities. For topics warranting additional, specific requirements regarding Generation facilities, Transmission facilities, and/or End-user facilities, an associated sub header is clearly provided for the reader.

These Dominion facility connection requirements address, but are not limited to, the following items (FAC-001 R3):

3.1. A written summary of Dominion’s plans to achieve the required system performance to avoid adverse impacts on reliability throughout the planning horizon:

Dominion has prepared this document for the purpose of complying with NERC’s Reliability Standards, specifically standard FAC-001. It has been written to individually address the connection requirements of generation, transmission, and electricity end-user facilities. These facility connection requirements shall be adhered to by any requesting Interconnection 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 when determining 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 Interconnection Customer substations at voltages of 69 kV or greater. It is not practical to include the particular requirements applicable to every possible transmission connection scenario since each connection is specific to the party requesting the connection and the transmission system at the point of customer connection. There are several factors to 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 as described in Exhibit A – Virginia Power North Carolina Power Transmission Planning Criteria.

The standards in this document apply to new facilities and to modification of existing facilities. The standards in effect at the time a facility was constructed or modified shall continue to apply to such facility until it is subsequently modified, or until Dominion or PJM determine the facility must be upgraded to the current standard to avoid unacceptable risk to the reliability or operation of the transmission system, or to the safety of workers or the public.

Typical connections are provided in Exhibit A – Virginia Power North Carolina Power Transmission Planning Criteria.
3.1.1. Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.

Utility Interconnections

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

Should Dominion receive an interconnection request that may impact a neighboring interconnected transmission system, Dominion 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.

Studies are performed in coordination with Dominion's Regional Transmission Organization (PJM Interconnection, L.L.C.), and 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, Dominion 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 with which Dominion engages in joint transmission interconnection activities:

- 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 (Multi-Regional Modeling Working Group)

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 reliably 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.

Wholesale Delivery Points

Dominion provides transmission service to wholesale delivery points throughout its service area under Mutual Operating Agreement(s) (MOA). The criteria for serving wholesale Interconnection Customers is the same as that used to serve Dominion's other customers and is predicated on “Good Utility Practice” 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 supplies are delivered over the company’s transmission facilities. Therefore, it is essential that wholesale Interconnection Customer load requirements be included in the company’s planning process.

The following criteria apply to all joint planning between Dominion and its wholesale Interconnection 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 Dominion’s Transmission Planning Criteria as stated in Exhibit A of this document shall apply to the connection of any wholesale Interconnection Customer to the Dominion’s transmission system.

Joint planning should be conducted periodically with each wholesale Interconnection 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 Interconnection Customer for their area and by the company for the general area around the Interconnection Customer.
- Special emphasis should be given to identify high load growth areas.
- The Interconnection Customer and the company will each prepare preliminary studies of their respective systems for meeting the future load requirements identified by the forecasts.
- The Interconnection 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 joint planning process will be necessary to accommodate third party delivery point requests. In these cases, the Dominion’s Electric Transmission Planning Department and, as needed, entities interconnected with Dominion’s transmission facilities, will expedite review of appropriate elements of the long-range plan in order to address such projects.

All delivery point requests should include a completed “Customer Request Form” as shown in Exhibit B.
3.1.2. Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.

The Interconnection Customer shall notify Dominion of planned additions of new facilities, or modifications to existing electrical facilities which have the potential to impact the reliability of the interconnected transmission systems. Interconnection Customers shall provide such notification as soon as it is feasible for them to do so, even if the information is in a preliminary form. Prompt notification is important so that Dominion can begin any needed coordination with other entities responsible for the reliability of interconnected transmission systems. The “Customer Request Form” as shown in “Exhibit B” shall be completed for initial requests as well as subsequent changes.

The form shall be submitted with sufficient advance notice to allow Dominion to:

- review the proposed addition or modification,
- conduct the necessary studies to assess the impact of the change on Dominion’s transmission system and/or neighboring facility owners,
- respond to the requesting facility owner, and
- complete any necessary modifications to Dominion facilities including ownership demarcation of equipment and/or Protection System(s) elements.

Subsequent changes to the approved design basis is interpreted to include, but are not limited to:

- changes to electrical equipment ratings
- changes to primary conductor(s) or connectors
- changes to transformer tap settings
- changes impacting Protection Systems such as:
  - significant source impedance changes at the interconnection point
  - modifications to Protection System communications equipment
  - modifications to Protection System relay settings
  - changes to breaker reclosing times

As modifications are determined to impact other parties, such as power generators, end users, and interconnect parties, Dominion will make appropriate notifications and pursue mutually agreeable resolutions as necessary.

3.1.3. Voltage level and MW and MVAR capacity or demand at point of connection.

Except as may be otherwise provided for in applicable tariffs or agreements, or as may be otherwise agreed by Dominion and the Interconnection Customer, the Interconnection Customer should use the Customer Request Form shown in Exhibit B to provide Dominion with the necessary information regarding the voltage level and MW and MVAR capacity or demand at point of connection. Since voltage and interconnection points are site-and project-specific, Dominion will perform studies and exercise engineering judgment to determine appropriate voltage levels, interconnection points, and system capabilities.
3.1.4. Breaker duty and surge protection.

Electrical circuit breakers shall be designed to meet or exceed the expected load and short circuit currents on the Interconnection Customer’s transmission system. High voltage circuit breakers and other current interrupting devices shall be designed to clear (interrupt) the worst case short circuit fault calculated for the protection zone as determined using fault analysis engineering programs. The calculation shall consider maximum expected system growth for 10 years beyond the project completion date.

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

Circuit breakers shall be designed and tested according to the latest IEEE C37 collection of standards.

Shielding, and surge protective devices shall meet the requirements as determined by lightning and switching surge analysis, and the latest IEEE C62 standards.

Basic Impulse Levels (BIL) for electrical equipment and high voltage substation buses shall meet or exceed Dominion’s standard values listed below.

<table>
<thead>
<tr>
<th>Nominal KV (phase to phase)</th>
<th>Basic Impulse Level (BIL)</th>
</tr>
</thead>
<tbody>
<tr>
<td>115</td>
<td>550</td>
</tr>
<tr>
<td>138</td>
<td>650</td>
</tr>
<tr>
<td>230</td>
<td>900</td>
</tr>
<tr>
<td>500</td>
<td>1550</td>
</tr>
</tbody>
</table>

The generation Interconnection Customer must meet the following design requirements described in NERC Reliability Standard FAC-001 and its SERC Supplement:

- Each party is responsible for designing equipment to meet the short circuit capabilities on their facilities.
- Each party is responsible for the ratings of their own interrupting devices. It is the responsibility of the Interconnection Customer to coordinate their relays and devices with Dominion’s transmission system.
- Parties shall provide existing and future fault current levels when requested.
- It is the responsibility of the Interconnection Customer to notify Dominion of any changes in their facilities that may cause an increase in fault currents (Generator and Transmission Interconnection Customers).
3.1.5. System protection and coordination.

The Interconnection Customer is responsible for providing a properly designed and tested Protection System that will safeguard the general public, protect its equipment against disturbances on Dominion’s system, and minimize the effects of disturbances from its facilities on Dominion’s equipment and transmission system. Protection Systems installed by the Interconnection Customer are expected to follow the latest IEEE C37 and C57 guides and standards for protective relaying systems and adhere to all NERC and PJM standards related to system protection. The Interconnection Customer’s Protection System shall coordinate with the interconnected Protection System owned by Dominion. 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 Dominion’s transmission grid.

Prior to the development of the Protection System, the Interconnection Customer should complete all appropriate studies, including, but not limited to, grounding studies, short circuit studies, stability studies, and power quality studies. These studies should be completed using Good Utility Practice and the results made available to Dominion upon request.

In addition, Dominion performs studies on existing Protection Systems which may require changes to the Interconnection Customer’s Protection System. In such cases, those customers will be notified and consulted regarding the changes required to ensure the reliable operation of Dominion’s transmission facilities.

Protection System Design

The Interconnection Customer shall design the Protection System to minimize the effects of disturbances from its facilities affecting Dominion’s interconnected transmission system or customers. The Protection System shall: be adequately sensitive to detect all abnormal faults and conditions, provide coordination between protection zones, and operate quickly in order to achieve transmission system reliability. In some cases, Dominion may require the Interconnection Customer to install additional equipment as necessary to address issues such as, but not limited to: relay overreach, transformer penetration, and weak source impedance. Dominion shall own and maintain transmission Protection System elements necessary to protect the transmission portion of the interconnection; however, Dominion is not responsible for protection of the Interconnection Customer’s equipment and other electrical assets.

The Protection System shall protect against or minimize the effects of these abnormal conditions: over/under-voltage, overload, short circuits, open circuits, phase imbalance, switching surges, lightning surges, and other harmful electrical conditions. Utility grade protective relays and fault clearing systems are to be provided on the interconnected power system. All protective relays shall meet or exceed ANSI/IEEE Standard C37.90. Mechanical and electrical logic and interlocking mechanisms may be required between interconnected facilities to ensure safe and reliable operation. These include, but are not limited to, breaker and switch auxiliary contacts, synch-check relays, and physical locking devices.

The following defines Dominion’s protection requirements for protecting lines connecting to Dominion’s transmission grid.

Dual Primary Phase and Ground Protection Systems

Protection Systems classified as Dual Primary are required for all transmission lines connecting to Dominion’s transmission grid. This scheme will require two independent
high speed, 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.

**Protection System Components**

The Interconnection Customer's Protection System, including the protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry, must be compatible with Dominion's standard design for common equipment and/or common zones of protection. Compatibility includes protection application, redundancy, operating speed, communication type, and communication medium.

The Protection System must be powered by a DC battery for reliability. The battery shall be sized to power continuous loads for a minimum of 8 hours and power all momentary tripping loads without a charger available. The battery sizing calculation shall be in accordance with IEEE 485. A DC under-voltage alarm must be provided for remote monitoring by the Facilities Owner, who shall take immediate action to restore power to the protective equipment.

**Protection System Misoperations**

The interconnection customer shall investigate all Protection System operations and misoperations, affecting the interconnected facility and will provide Dominion with the findings of the investigations upon request. Likewise, Dominion will cooperate with the Interconnection Customer and will provide any necessary findings related to Protection System operations and misoperations affecting the interconnected facility.

3.1.6. **Metering and telecommunications.**

**Metering**

Dominion approved revenue metering equipment shall be installed for energy accounting and billing purposes. Except as may be otherwise provided for in applicable tariffs or agreements, or as may be otherwise agreed by Dominion and the Interconnection Customer, the Interconnection Customer shall install, own, operate and maintain all revenue metering equipment as set forth below.

Interconnection Customers that will be a PJM market participant shall install metering that shall be of sufficient quality to meet the requirements as defined in PJM Manuals 14A – Generation and Transmission Interconnection Process, 14C – Generation and Transmission Interconnection Facility Construction and 14D – Generator Operational Requirements. Additional requirements may be applicable on a case-by-case basis.

Revenue metering equipment includes, but is not limited to, current transformers, voltage transformers, revenue meters, meter sockets, test switches, communication circuits and associated devices. The revenue metering equipment shall be located at the Interconnection Customer’s facility unless otherwise agreed to by Dominion, PJM, and the Interconnection Customer (referred to collectively in this section as the “Parties”). The revenue metering equipment shall meet or exceed all applicable industry standards (e.g., NERC, PJM, ANSI, IEEE, and NEMA). At least (N-1) metering elements shall be used for the revenue metering, where N is the number of wires in the electrical system associated with the revenue metering.
Three metering elements shall be the standard for revenue metering unless otherwise agreed to by the Parties. The revenue metering installation shall meet all applicable industry standards for phase-to-phase and phase-to-ground electrical clearances.

Dominion will provide the Interconnection Customer with manufacturer's installation information for the current and voltage transformers when these devices will be furnished by Dominion and installed by the Interconnection Customer.

**Revenue Meters**

The revenue meters shall be capable of recording, storing, and transmitting bidirectional megawatt-hour (MWh) data and megavar-hour (MVARh) data. However, if required by the applicable tariffs, or if mutually agreed by the parties, the revenue meters shall instead record bi-directional kilowatt-hour (kWh) data and kilovarhour (kVARh) data. In general, this data shall be recorded in hourly intervals unless other interval lengths are required by the applicable tariffs or agreed upon by the Parties.

The revenue meters shall have an accuracy class of 0.2% standards as defined in ANSI C12.20. In addition, the revenue meter should meet ANSI C12.1 and C12.10 standards. Meters in service may be tested by Dominion, any regulatory agency having jurisdiction over the interconnection, or any other lawfully constituted authority having jurisdiction over meter accuracy.

**Revenue Metering Current Transformers**

The revenue meters shall be connected to current transformers (CTs) having a minimum metering accuracy class of 0.15% (as defined in IEEE C57.13) at a minimum burden designation of B-1.8 from 1% of nameplate to rating factor. CTs with standard accuracy and/or lower burden designations may be allowed by Dominion in special cases, but the secondary burden on the CTs must not exceed the nameplate burden rating. In addition, the CTs should meet the ANSI C12.11 standard. The continuous current on the CTs shall not exceed the primary nameplate rating with the thermal current rating factor (RF) applied. The available fault current must not exceed the mechanical and short time thermal limits of the CTs. The revenue meters shall generally be connected to dedicated metering CT secondary circuits and should not share the same circuits with relays or other devices. In cases where power flow varies significantly (e.g., at wind generation facilities), the Interconnection Customer may be required to provide extended range CTs or additional metering equipment at their own expense.

**Revenue Metering Voltage Transformers**

The revenue meters shall be connected to voltage transformers (VTs) or coupling capacitor voltage transformers (CCVTs) having a minimum metering accuracy class of 0.3% (as defined in IEEE C57.13) with a minimum burden on the VTs or CCVTs that exceeds the circuit burden. In addition, the VTs and CCVTs should meet the ANSI C12.11 standard. The revenue meters shall be connected to dedicated metering VT or CCVT secondary circuits and should not share the same circuits with relays or other devices; however, if the VTs or CCVTs have separate secondary windings used for relays or other devices, the revenue meters may be connected to dedicated secondary windings of such VTs or CCVTs. VTs are preferred for revenue metering. The use of CCVTs for revenue metering shall be limited to facilities connecting to Dominion system voltages 115 kV and higher or where Dominion has determined it is impractical to use VTs for technical reasons.
Revenue Metering Data Communications

The Interconnection Customer shall, at its own expense, install, operate, test, and maintain any communications equipment required by Dominion to remotely retrieve revenue metering data from the Interconnection Customer’s facility on a real-time or periodic basis as specified in the sections below for Wholesale Generation Facilities, Transmission Facilities, and End User Facilities. The communication capability of remote interrogation of the revenue data should be compatible with commonly used billing data systems such as MV-90. The Interconnection Customer shall also be responsible for any high voltage isolation equipment that the local telecommunications company may require at the Interconnection Customer’s facility to protect their communications systems from damaging transient voltages that can occur in electrical substations and generation facilities.

Dominion will provide the Interconnection Customer access to bi-directional kWh and kVARh pulses from the Dominion revenue meters installed at Interconnection Customer facilities. The pulses, which will be provided upon request, shall be used as the source of the revenue metering data where applicable. Alternatively, kWh and kVARh register accumulator data may be provided by other means, e.g. DNP, MODBUS or similar protocol, to the Interconnection Customer facilities, in lieu of, or in addition to, analog kWh and kVARh pulses, if such arrangements are agreed upon by both parties.

Operational Metering Data from Revenue Meters

Operational metering data (e.g., MW and MVAR) is generally not available from Dominion revenue meters that are provided by Dominion at Interconnection Customer facilities. Except as may be otherwise provided for in applicable tariffs or agreements, or may be otherwise agreed by Dominion and the Interconnection Customer, the Interconnection Customer shall, at its own expense, install, operate, test, and maintain any metering and communications equipment necessary to provide operational metering data required from the Interconnection Customer’s facility by one or more of the Parties.

Revenue meters shall be capable of communicating with data acquisition system (“DAS”) equipment such as Remote Terminal Unit (“RTU”) to provide the following real-time bi-directional power and energy data for operational purposes:

- instantaneous power flows
- per phase and three-phase averaged Root-Mean-Squared (“RMS”) voltages
- per phase and three-phase averaged RMS currents with at least two decimal points

A continuous accumulating record of active and reactive energy flows shall be provided by means of the registers on the meters. The revenue meter(s) shall be capable of providing bi-directional energy data flow in either kyz pulse signals format, or accumulated counters to RTU. Energy data flow accumulator counters may also include register accumulator data delivered to RTU via DNP, MODBUS or similar protocol. All Parties shall share the same data register buffers regardless of the types of employed data communication methods. If the accumulation counter method is used, the owner of the meter shall be responsible for freezing the accumulator buffers and no other Party shall freeze them. The accumulator freezing signals shall be synchronized to Universal Time Coordination (“UTC”) within 1/2 seconds.
The revenue meters’ internal clocks and real-time DAS equipment shall be synchronized with Universal Time Coordination (“UTC”) with 15 seconds resolution.

Revenue Metering Access, Security, and Testing

Where Dominion provides revenue metering equipment, the Interconnection Customer shall grant Dominion employees and authorized agents’ access to the equipment at all reasonable hours and for any reasonable purpose. Regardless of meter ownership, the Interconnection Customer shall not permit unauthorized persons to have access to the revenue metering equipment.

The meters, test switches and any other secondary devices that could have an impact on the performance of the revenue metering shall be sealed at all times and the seals shall be broken by the party responsible for the equipment only when tests, adjustments, and/or repairs are required.

The revenue metering shall be tested for accuracy as specified by the applicable interconnection service agreement, PJM requirements or regulatory commission regulations by the owner of the metering equipment.

Wholesale Generation Facilities

For the interconnection facilities of Wholesale Generators, except as may be otherwise provided for in applicable tariffs or agreements, or as may be otherwise agreed by Dominion and the Interconnection Customer, the revenue metering equipment shall be located at the Interconnection Customer's facility. The revenue metering shall be compensated for losses to the Point of Interconnection (POI) if the metering equipment is not located at the POI.

The revenue metering CTs and VTs shall be installed on the transmission voltage side of the Interconnection Customer’s generator step-up transformer(s) or facility main step-up transformer and/or station service power transformers.

The specific revenue metering requirements for wholesale generation facilities will fall under one of the following categories:

Dominion Revenue Metering Requirements for Generation Facilities Connected 69 kV and Higher:

The Interconnection Customer shall install, own, operate, test, and maintain the revenue metering equipment at the Interconnection Customer’s expense. A redundant revenue meter and real-time Supervisory Control and Data Acquisition (SCADA) data is also required. The SCADA data consists of analog MW and MVAR at all generation, load, and transmission line terminals; analog kV at all buses 69 kV and greater; circuit breaker open/close status for all breakers; other device status points (for example, automatic reclosing on/off). It is preferred that the redundant meter have a different method of telecommunications than the primary meter. Dominion will provide revenue metering for station service power supply at a generation facility if the supply is from the Dominion distribution system.
Dominion Revenue Metering Requirements for Generation Facilities Connected Below 69 kV:
Dominion shall install own, operate, test and maintain the revenue metering at the Interconnection Customer’s expense. A redundant revenue meter is also required. It is preferred that the redundant meter have a different method of telecommunications than the primary meter.

Dominion Revenue Metering Requirements for Behind-The-Meter Generation Facilities Participating in the PJM or Wholesale Energy Markets:
Dominion shall own, operate, test, and maintain the revenue metering equipment at the POI, except as otherwise specified by the applicable retail tariff or interconnection service agreement. The physical arrangements of such facilities are often complex. As such, Dominion will make a case-specific review of each installation and will determine the revenue metering required. Any additional metering equipment or metering data that one or more of the Parties may require for the generation equipment is the responsibility of the Interconnection Customer.

Specific Revenue Metering Requirements for Existing Non-Utility Generator Facilities That Are Ending Power Purchase Agreements with Dominion:
For an existing non-utility generator (NUG) that is ending its power purchase agreements with Dominion and will sell its power in the PJM energy market, Dominion shall continue to own, operate, test, and maintain the existing revenue metering equipment at the Interconnection Customer’s expense, except as otherwise specified by the applicable tariff or service agreement. The Interconnection Customer’s RTU shall provide Dominion access to the operational and revenue metering data specified in Telecommunication Section.

Transmission Owner Facilities
For the interconnection facilities of Transmission Owners, except as may be otherwise provided for in applicable tariffs or agreements, or as may be otherwise agreed by Dominion and the Interconnection Customer, the Interconnection Customer shall install, own, operate, test, and maintain the revenue metering equipment at its facility. The revenue metering shall be compensated for losses to the POI if the metering equipment is not located at the POI.

The revenue metering CTs and VTs shall be installed at the point(s) where the Interconnection Customer’s facility connects to the Dominion transmission system. The exact location of the revenue metering CTs and VTs shall be as determined by agreement between Dominion and the Interconnection Customer.

• The Interconnection Customer shall provide a primary and redundant revenue meters and along with SCADA data. It is preferred that the redundant meter have a different method of telecommunications than the primary meter.

End-User Facilities
Except as may be otherwise provided for in applicable tariffs or agreements, or as may be otherwise agreed by Dominion and the Interconnection Customer, the provisions of this section

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apply to all end user revenue metering whether installed by Dominion or the interconnected end user.

For the interconnected facilities of end users, the revenue metering shall be installed on either the primary side or the secondary side of the Interconnection Customer’s step-down transformer in accordance with the applicable interconnection agreements. Dominion will use its best engineering judgment to determine the appropriate location for the revenue metering equipment if the interconnection agreement provides Dominion the option to choose either the primary side or the secondary side.

If the revenue metering is installed on the primary side of the Interconnection Customer’s step-down transformer, the Dominion CTs and VTs shall be located on the high side of the Interconnection Customer’s step-down transformer. When revenue metering is installed by the Interconnection Customer, the proposed metering installation design must be reviewed and accepted by Dominion prior to installation.

If the revenue metering is installed on the secondary side of the Interconnection Customer’s step-down transformer, it shall be compensated for losses in the transformer. The revenue metering shall also be compensated for losses in any significant length of conductors between the metering point, the step-down transformer and the POI.

If Interconnection Customer owned revenue metering is compensated, the Interconnection Customer shall provide Dominion with the following information:

- Certified manufacturer test data for the step-down transformer including nameplate ratings, no-load losses, load losses, exciting current, and impedance.
- Primary side voltage tap setting planned for the step-down transformer if equipped with a no-load tap changer. The transformer test data specified above shall be provided for all available taps.
- Information regarding the conductors on the primary side of the Interconnection Customer's step-down transformer, if applicable, and the secondary side including conductor type, number of conductors per phase, length, resistance and reactance (in Ohms per conductor per 1000 feet or per mile).
- If Dominion specifies compensated revenue metering on the secondary side of a step-down transformer, the Interconnection Customer may install the CTs and VTs in any one of the following configurations after Dominion review and acceptance of the proposed design:
  - An outdoor overhead metering structure with a visible break switches or disconnects on both the incoming and load sides.
  - Pad mounted metering enclosure with dead-front disconnecting elbows on both the incoming and load sides.
  - Switchgear metering compartment with a visible break switch or disconnect on both the incoming and load sides. The compartment must be sealable with doors on the front and back. The CTs and VTs can be picked up from the closest Dominion office to the interconnecting site. The Interconnection Customer must provide Dominion with detailed metering compartment drawings (front, side, and rear views) that show the orientation of the CTs on the bus work and indicate electrical clearances. There must be adequate working clearances around the CTs.
and VT secondary terminal boxes for Dominion meter personnel to install the secondary wires.

For end-user Interconnection Customer’s facility with behind-the-meter generation, Dominion may require the Interconnection Customer to install, own, operate, test, and maintain additional revenue metering at the output of the generation equipment, which shall meet any requirement specified in the applicable tariffs or interconnection agreements. If Interconnection Customer owned metering is installed, the Interconnection Customer shall also provide Dominion with the generation revenue metering data if required.

When the end user has non-conforming load, a primary revenue meter along with SCADA data is required. Non-conforming load is load of more than 50 MW that exhibits one of more of the following characteristics:

- Expected load swings of approximately 50 MW or more and ramp rates of approximately 10 MW or more per minute
- Loads with expected daily reactive power ramp rates of 50 MVAR or more per minute
- Loads known to create voltage flicker exceeding the limits set out in the Institute of Electrical and Electronics Engineers (IEEE) Standard 1453
- Loads known to create harmonic current distortions exceeding the limits set out in IEEE Standard 519

**Telecommunications**

In recognition that the coordination of the system operations by the Parties may be facilitated by the sharing of power flow and other real-time information from meters and other equipment at the Interconnection Points, the Parties may agree to cooperate on the installation and operation of data acquisition system (“DAS”) equipment including, but not limited to, remote terminal units (“RTU”), meters, MW/MVAR and Volt transducers, telecommunication devices, lease lines, and any related equipment at points which shall from time to time be mutually agreed upon.

If a backup telemetry system or data is required by one Party for their own use, the requesting Party shall be responsible for installing and/or maintaining the field devices and associated telecommunication system at their cost.

At a minimum, the following real-time data shall be provided to all Parties: three phase bi-directional energy flows (e.g., MWh, MVARh), three phase instantaneous power flows (e.g. MW, MVAR), per phase RMS voltages, and per phase RMS currents with at least two decimal points resolution shall be provided. In addition to the real-time data, the status of all switching devices associated with the interconnection circuit(s) shall be provided. The real-time data requirements defined in the PJM manuals, including PJM Manual 01 – Control Center and Data Exchange Requirements and PJM Manual 03 – Transmission Operations, shall be provided to PJM to fulfill its roles as Reliability Coordinator (RC), Balancing Authority (BA), and Transmission Operator (TOP).

Metering, Data, and Communications requirements between a generation facility and PJM will be resolved in the kickoff meeting between the PJM client manager and the generation owner, as described in §4.2.2 of PJM Manual 14D – Generator Operational Requirements.
3.1.7. Grounding and safety issues.

All electrical equipment, electrical components, fences, metal buildings, protective controls, and structures shall be properly grounded and bonded. A safe grounding design must accomplish two basic functions:

1. **Personnel safety**: Ensure that facility personnel, their contractors and the public are not exposed to harmful step-and-touch potentials.

2. **Current path to earth**: Provide a path for electric currents into the earth under normal and fault conditions. Under normal conditions currents will not exceed any operating and equipment limits. Under fault conditions the currents will not adversely affect the continuity of service.

Accordingly, each electrical facility must have a grounding system or grid that solidly grounds all metallic structures and equipment in accordance with standards outlined in the latest revisions of IEEE 80, IEEE Guide for Safety in AC Substation Grounding, and IEEE C2, National Electrical Safety Code (NESC).

Designs must ensure that step and touch potentials and transferred voltages are limited to safe levels. Furthermore, testing must be performed to verify the integrity of the installed grounding system and ensure safe step and touch potential parameters have been met in accordance with the latest revision of IEEE 80.

When various switching devices are opened on an energized circuit, its ground reference may be lost if all sources are not effectively grounded. This situation may cause over voltages that can affect personnel safety and damage equipment. This is especially true when one phase becomes short-circuited to ground. Therefore, the interconnected transmission power system is to be effectively grounded from all sources. This is defined as:

\[
\frac{X_o}{X_1} \leq 3 \\
\frac{R_o}{X_1} \leq 1
\]

This relationship assumes \( R_1/X_1 = 0 \), which is a worst case condition.

Interconnected generators should provide for effective system grounding of the high-side transmission equipment by means of a grounded high-voltage generation step-up transformer.

Shield wires should be considered, where applicable, to protect conductors and equipment from lightning strikes. A recommendation for maximum resistance values for all new stand-alone (not connected to a ground grid) structures carrying shield wires are as follows: 25 Ohms for structures supporting facilities at or below 230kV, and 20 Ohms for structures supporting facilities from above 230kV to 500kV.

Safety is of utmost importance. Any work carried out within a facility shall be performed in accordance with all applicable laws, rules, and regulations and in compliance with Occupational Safety and Health Administration (OSHA), NESC, and good utility practice. Automatic and manual disconnect devices are to be provided as a means of removing all sources of current to any particular element of the power system. Only trained operators are to perform switching functions within a facility under the direction of the responsible dispatcher or designated person as outlined in the NESC. The Interconnection Customer and Dominion must agree to switching and Lock Out/Tag Out procedures that will be adhered to at all times.
for the safety of all personnel. Dominion will follow its own standard operating practices and grounding procedures for safety of personnel.

3.1.8. Insulation and insulation coordination.

Insulation coordination is defined by IEEE 62.22 as “the selection of insulation strength consistent with expected over-voltages to obtain an acceptable risk of failure”. Insulation coordination must be designed properly both for personnel safety and in order to protect the electrical equipment from the harmful over-voltages resulting from faults, lightning or switching transients. An insulation design must accomplish two basic functions:

- Electrical isolation: Electrically isolate the maximum anticipated voltage of energized parts from supporting structures or ground.
- Mechanical support: Mechanically support energized parts as intended.

Surge arresters and static wires are used to safeguard the electric power equipment against harmful over-voltages. Basic Impulse Levels (BIL) for electrical equipment and high voltage substation buses shall meet or exceed Dominion’s standard listed below.

<table>
<thead>
<tr>
<th>Nominal KV (phase to phase)</th>
<th>Basic Impulse Level (BIL)</th>
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<tbody>
<tr>
<td>115</td>
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<td>1550</td>
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</table>

Equipment BIL shielding and surge protection shall be designed as determined by lightning and switching surge analysis to meet all applicable ANSI/IEEE standards and Dominion transmission and substation engineering standards.

Dominion Specifications for Transmission Line Insulators include:

- TE VEP 1115 – Suspension Insulators
- TE VEP 1117 – Suspension Type Non Ceramic Insulators
- TE VEP 1118 – Polymer Post Insulators/Non-Ceramic Insulators

ANSI/IEEE standards include, but are not limited to:

- ANSI C29 collection of standards – Insulators for Electric Power Lines

Interconnection facilities to be constructed in areas with salt spray contamination or other types of contamination shall be properly designed to meet or exceed the performance of facilities in a non-contaminated area. Typically this involves more insulation, higher leakage distances and/or non-standard insulating components and materials.

The following shall be submitted, as applicable, with the Customer Request Form (Exhibit B) for evaluation as part of the interconnection plan:

- Surge arrester ratings
- Basic switching surge levels
- Surge arrester, conductor spacing and gap application

Level 1 - Public Information
3.1.9. Voltage, Reactive Power, and power factor control.

Generation Facilities

PJM is responsible for ensuring the stability and reliability of its electric transmission system. In turn, all generation Interconnection Customers are responsible for operating their units in a stable manner while those units are connected to Dominion’s facilities. Generator excitation and prime mover controls are key elements in ensuring electric system stability and reliability. To meet its responsibility, PJM must have the ability to establish voltage and governor control requirements for all generators connected to its system, including units connected through Dominion’s facilities. These requirements may vary depending on the location, size, and type of generation installed.

Generator Interconnection Customers are required, with oversight by PJM, to follow the current NERC and SERC standards and guides for generator operation, protection, and control.

- All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in automatic voltage control mode unless approved otherwise by PJM. PJM and Dominion shall be notified any time a generator control system is removed from service or its logic is modified. These control systems may include but are not limited to: voltage regulators, power system stabilizers, governor and prime mover controls.
- Generators shall maintain a network voltage or reactive power output as required by Dominion, with governance by PJM, within the reactive capability of the units. Generator step-up and auxiliary transformer shall have their tap settings coordinated with electric system voltage requirements.
- Temporary excursions in voltage, frequency, and real and reactive power output that a generator shall be able to sustain shall be defined and coordinated on a regional basis.
- Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator’s short duration capabilities and protective relays.
- Prime mover controls (governors) shall operate with appropriate speed/load characteristics to regulate frequency.

All interconnected generation must adhere to power factor requirements for new generator interconnection requests and increase to existing generators as documented in PJM Manual 14A – Generation and Transmission Interconnection Process, Section 5: Additional Generator Requirements. Asynchronous generators connected to the transmission systems shall be studied in the PJM System Impact Study to determine the reactive power compensation required. All interconnected generation must meet the following criteria:
Facility Connection Requirements

NERC Standard/Requirement#: FAC-001 (all requirements)

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- All synchronous and asynchronous generators connected to the interconnected transmission systems shall maintain a power factor of at least 0.95 leading to 0.95 lagging measured at the Point of Interconnection.

- All new intermittent, asynchronous generators interconnecting to the transmission system that cannot provide control of real power output (wind, solar) will be studied for reactive power capabilities in a manner that considers the variability of the entire intermittent generation fleet within the Dominion footprint; Dominion will provide input and support these studies if deemed necessary, following these requirements.

- Voltages at the Point of Interconnection of any generating station should not vary more than 1.0% for expected changes in generation output caused by fluctuations in the prime mover output.

- The System Impact Study for asynchronous, intermittent generation will consider the generator under study as well as variability of the entire intermittent generation fleet when determining if the voltage fluctuation criteria is met.

- New variable generation resources that cannot meet the 1% voltage deviation criteria will provide dynamic reactive compensation as specified in the PJM System Impact Study, with Dominion support and studies incorporated.

Specific requirements for voltage regulators, power system stabilizers, governor controls, and remote control and telemetry of such devices will be determined during the System Impact Study. The specific requirements for a generator will become part of the Interconnection Service Agreement. (PJM Manual 14A, Section 2: Generation and Transmission Interconnection Planning Process).

Transmission Facilities

The transmission system must be capable of moving electric power from areas of generation to areas of load under a wide variety of expected system conditions. Adequate reactive power supplies are of paramount importance to the capability of the transmission system to reliably support a wide variety of transfers. Transmission facilities must be designed to minimize excessively high voltages during light transmission loading conditions, yet have adequate reactive supplies to support system voltage during heavy transmission loading conditions.

End-User Facilities

The voltage variation limitations for interconnections with End-User facilities are as stated in the applicable tariff or agreement. End-User facilities connected directly to the transmission system should plan and design their systems to operate at close to unity power factor to minimize the reactive power burden on the transmission system.
3.1.10. Power quality impacts.

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.

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 should meet the requirements contained in the latest revision of IEEE Standard 519.

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

3.1.11. Equipment Ratings.

Electrical equipment and associated interconnected facilities shall be capable of safely interrupting the worst case short circuit faults calculated for the protection zone.

All current-carrying equipment and devices shall be designed to carry the maximum loads that are predicted and used in load flow analysis, tested against all applicable NERC standards, PJM Transmission Planning Criteria and Dominion Transmission Planning Criteria. Loads exceeding nameplate or normal design capacities are acceptable only when allowed by manufacturers’ design documentation or standard industry practice or by Dominion’s Facility Rating Methodology (FRM).

Circuit breakers and disconnect switches shall be designed and tested according to the latest IEEE C37 collection of standards. Power transformer and Instrument transformers shall be designed and tested according of IEEE C57 standards. Rigid bus structures shall be designed to meet the latest revision to IEEE 605. Current carrying conductors and tubing shall be braced and supported for the expected worst case, short circuit currents, ice loading and wind loading. For overhead line facilities, ground clearance shall be maintained according to the latest IEEE C2, National Electrical Safety Code (NESC). All facilities at voltages greater than 230kV should be considered Extra High Voltage (EHV) and designed accordingly.

Equipment BILs, shielding, and surge protective device application must meet requirements as determined by the latest IEEE C62 standards. Dominion will provide the BIL for the system in the interconnection area. Also, equipment must meet all applicable ANSI/IEEE standards and specifications communicated by PJM and Dominion. Basic Impulse Levels (BIL) for electrical equipment and high voltage substation buses shall meet or exceed Dominion’s standard listed below.

Level 1 - Public Information
3.1.12. Synchronizing of facilities.

Synchronizing equipment consisting of potential devices and associated protective relay and controls is required on facilities where energy can be sourced on both sides of an interconnection circuit breaker. The Interconnection Customer shall not synchronize with the transmission system prior to obtaining approval from Dominion.

The following explains the various synchronizing options.

**Generation Facilities**

Live line, dead bus (LLDB) control is used in the interconnection circuit breaker reclosing scheme when generation facilities are connected to Dominion. The circuit breaker cannot be closed unless the generation side has zero voltage. The interconnection circuit breaker shall not be used to synchronize a generator to the transmission system. Instead, the generation facilities shall have their own synchronizing facilities. In the event a generation Interconnection Customer’s facility becomes disconnected from Dominion’s system, it shall remain disconnected until system voltage and frequency are within an established range. In all scenarios, Dominion shall retain operational control of the interconnection breaker.

**Interconnected and Separate Systems for Generators**

The Interconnection Customer may elect to run its generator in parallel (interconnected) with Dominion or as a separate system with the capability of nonparallel load transfer between the two independent systems. The two methods of operation are outlined as follows:

**Parallel system**

A parallel system is one in which the Interconnection Customer’s generation equipment can be connected to Dominion’s system resulting in a transfer of power between the two systems. A consequence of such parallel operation is that the parallel generator becomes an electrical part of the Dominion system, which must be considered in the operation and protection of Dominion’s facilities. The general and specific requirements for parallel generation installations are discussed in this document.

Synchronizing equipment consisting of potential transformers and associated protective relaying/controls is required on facilities where energy can be sourced on both sides of an interconnection circuit breaker. This equipment serves the following purposes:

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### Table: Nominal KV (phase to phase) vs. Basic Impulse Level (BIL)

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- Verifies the voltages on both sides of a circuit breaker fall within set tolerances, which must meet Dominion's approval, as to the magnitude and phase angle established by system conditions.
- Supervises the closing and automatic reclosing of the circuit breaker.
- Prevents the closing of the circuit breaker when the two systems are out of sync.

Voltage magnitudes, phase angles, and frequency constraints shall be determined on a case-by-case basis.

**Separate system with nonparallel load transfer capability**

A separate system is one in which there is no possibility of delivering energy to the Dominion system from the Interconnection Customer’s equipment. The Interconnection Customer may maintain the capability of transferring load between the two systems, but such transfer must be accomplished in an open-transition or nonparallel mode. This can be accomplished by either an electrically or mechanically interlocked switching arrangement that precludes both the switch connecting the load to Dominion’s system and the switch connecting the load to the Interconnection Customer’s generation being in the closed position simultaneously. If the Interconnection Customer has a separate system, the Interconnection Customer shall not operate the generation until Dominion has verified that the transfer scheme meets the nonparallel requirements. This verification will be accomplished by review and approval of drawings and equipment specifications by Dominion and, if Dominion so elects, by field inspection of the transfer scheme. Dominion will not be responsible for approving the Interconnection Customer’s generation equipment and assumes no responsibility for its design or operation.

**Testing**
Dominion requires interconnecting entities with protection systems which coordinate with Dominion’s transmission network protection systems to have a documented maintenance program for those systems in accordance with NERC PRC-005 requirements. Documentation of the maintenance program shall be supplied to Dominion upon request. Additionally, the interconnecting entity, on maintenance intervals identified within their documented program and following any apparent malfunction of the protection equipment, shall perform and document both calibration and functional trip tests of its protection equipment as outlined within its maintenance program. Customer shall maintain evidence of such activities and make them available to Dominion upon request.

**Coordination**
Dominion may remove its lines and associated equipment from service for testing of relays and maintenance of lines or substations in accordance with its maintenance program. The Interconnection Customer, Dominion and PJM will coordinate for these planned outages.

The interconnection parties agree to confer regularly to coordinate the planning, scheduling and performance of preventative and corrective maintenance on the Interconnection Customer’s facility, the Interconnection Facilities and associated facilities owned by Dominion. The Interconnection Customer must coordinate its approach and schedule for maintenance and testing with Dominion to ensure the reliability of the bulk electric system.

**Generator Interconnection**
On occasion, the generation Interconnection Customer may not be allowed to operate in parallel with the Dominion Transmission or Distribution system. A generator Interconnection Customer with multiple interconnection points may be permitted to operate only in parallel with specific lines so Dominion can perform “Liveline Maintenance” on the facilities serving the generator Interconnection Customer. The generator Interconnection Customer, Dominion and, as needed, PJM, will coordinate with these conditions and requests.

PJM is the Transmission Operator for Dominion transmission system. The interconnection will be operated consistent with PJM requirements and procedures. Specific transmission conditions and procedures for operation of Transmission Facilities within PJM are found in Manual 3 – Transmission Operations on the PJM website (www.pjm.com).

Generator Interconnection

The Transmission System is designed to automatically activate a load-shed program as required by SERC in the event of an under-frequency system disturbance. A generation Interconnection Customer shall implement under-frequency and over-frequency relay set points for the generation Interconnection Customer as required by SERC to ensure ‘ride through’ capability of the Transmission System. The generation Interconnection Customer facility is to stay connected to and synchronized with the transmission system during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice. The response of a generation Interconnection Customer’s facility to frequency deviations of predetermined magnitudes; both under-frequency and over-frequency deviations are studied and coordinated with PJM in accordance with Good Utility Practice. Additional information is found in PJM Manual 14D – Generator Operational Requirements.

3.1.15. Inspection requirements for existing or new facilities.

Dominion has established inspections as a component of its maintenance program for Dominion owned assets. Dominion may require right of access to the Interconnection Customer’s facility for purposes of conducting inspections: to include observing tests, visual inspections, and auditing records as required by NERC PRC-005.

Additionally, Dominion may require right of access to conduct initial (pre-operational) inspection and/or require copies of pre-operational procedures and test reports.

Each party shall, at its own expense, have the right to observe the testing of any of the other party’s metering equipment whose performance may reasonably be expected to affect the accuracy of the observing party’s telemetry and revenue. If requested, each party shall notify the other in advance of metering or other equipment testing and maintenance, and may have a representative attend and be present during such testing.

If Dominion identifies any deficiencies, defects, or inconsistencies of the Interconnection Customer’s facility that may adversely affect the reliability of the bulk power system and/or potentially constitute a compliance concern for Dominion, then Dominion shall provide notice to the Interconnection Customer outlining the concern and the suggested corrective action. Customer shall provide Dominion with a corrective action plan resolving identified concern(s).

If Customer observes any deficiencies, defects, or inconsistencies of its Interconnection facility that may adversely affect the reliability of the bulk power system and/or potentially constitute a compliance concern for Dominion, then the Customer shall provide notice to Dominion outlining the identified concern and the corrective actions that will be taken to resolve the concern.
3.1.16. Communications and procedures during normal and emergency operating 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. Dominion and the Interconnection Customer shall maintain communications which shall include, but not be limited to exchanging up-to-date information regarding:

- contact information for maintenance personnel
- maintenance schedules
- meter tests
- relay tests
- system paralleling or separation
- scheduled or unscheduled shutdowns
- equipment clearances
- periodic load reports
- tagging of interconnection interrupting devices
- billing
- other routine communication

In case of emergency or abnormal operating conditions, various communication channels may be used depending on the interconnect category. Emergency telephone numbers should be agreed upon by both parties prior to the date of initial interconnection. Each Interconnection Party shall notify the other parties promptly when it becomes aware of an emergency condition that may reasonably be expected to affect operation of the Interconnection Customer’s facility, the Interconnection Facilities, the Dominion Interconnection Facilities, or the transmission system.

Generation and Transmission Interconnection Customer Obligations

Generation and Transmission Interconnection Customers shall install and maintain satisfactory operating communications with PJM's system dispatcher or its other designated representative and with Dominion system dispatcher. Generation and Transmission Interconnection Customers shall provide standard voice line, dedicated voice line, and facsimile communications at their facility control room through use of the public telephone system. Generation and Transmission Interconnection Customers also shall provide and maintain backup communication links as specified by both PJM and Dominion for use during abnormal conditions. Satellite phones compatible with PJM and Dominion equipment should be available for emergency communications. Generation and Transmission Interconnection Customers further shall provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to PJM and Dominion as necessary to conform to applicable technical requirements and standards.
4. DOCUMENT MAINTENANCE AND AVAILABILITY PER NERC FAC-001 R4

NERC FAC-001 R4 states:

“The Transmission Owner shall maintain and update its Facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Entity, and ERO on request (five business days).”

The Company reviews this Facility Connection Requirements document and makes changes as needed, or when the FAC-001 standard changes. These revisions are tracked in the Revision History section below.

Dominion’s most recently approved Facility Connection Requirements document is publically and instantly available on the Company’s web site ‘www.dom.com’.

5. APPLICABILITY

NERC Reliability Standard FAC-001 applies to Virginia Electric and Power Company - (DP, LSE, TO) as a registered TO with NERC.
6. DEFINITIONS

6.1. Definitions

Wherever used in this document with initial capitalization, the following terms shall have the meanings as specified below.

- **Capacity**—The seasonal maximum generating capability of the generation Interconnection Customer's 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 Interconnection Customer’s 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 generation Interconnection Customer 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 generation Interconnection Customer’s facility such that the output of the facility must be shutdown or curtailed to avoid damaging the facility or the Transmission System.
- **Good Utility Practice**—Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region.
- **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, equipment, devices and apparatus owned or leased by, or under contract to each party presently in place or proposed to be installed, which are necessary to connect the Interconnection Customer’s facility(ies) to the Dominion Transmission System.
- **Interconnection Customer**—A transmission, generation, or end user connected to, or seeking to connect to, the Dominion transmission system.
- **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 Interconnection Customer’s 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 Interconnection Customer’s facility is connected. PJM Interconnection, L.L.C. is Dominion’s RTO.
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- **Transmission System**—The facilities owned 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.

6.2. 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.

- **ANSI**—American National Standards Institute
- **IEEE**—Institute of Electrical and Electronic Engineers
- **NERC**—North American Electric Reliability Corporation
- **OATT**—PJM Open Access Transmission Tariff
- **PCC**—Point of Common Coupling
- **SERC**—SERC Reliability Corporation

Level 1 - Public Information
7. REVISION HISTORY

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<td>See Details for Revision 10.0 below</td>
<td>William F. Bigdely</td>
<td>01/15/2015</td>
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</tbody>
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Details for Revision 1.0

- Revised to include information regarding Dominion’s generation interconnection procedures/process.

Details for Revision 2.0

- 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.

Details for Revision 3.0

Revised to reflect the following:
- Updates to NERC Reliability Standards
- Dominion’s PJM Membership
- References to new SERC regional studies processes

Details for Revision 4.0

Revised to reflect the following:
- PJM Generation Queue Changes Section 4
- General Revisions all sections

Details for Revision 5.0

Revised the following:
- Section 2.12: Clarified content regarding synchronizing of facilities.
- Exhibit A: Changed loading criteria to not exceed emergency rating of transmission facility.
- Various errata changes.
Details for Revision 6.0
- Comprehensive overhaul to better align with the numerical flow of NERC Reliability Standard FAC-001.

Details for Revision 7.0
Revised to reflect the following:
- Annual review of Facility Connection Requirement document.
- Updated titles for approval process on page 1.
- Incorporated changes to reflect FERC approval of FAC-001-1 effective 11/25/2013.
- Section 3.1.5 – Removed “Coordination and Compatibility” and “Performance Tracking and Compliance”; Added “Protection System Misoperations”.
- Section 3.1.13 – Added “Testing” paragraph
- Various errata changes.

Details for Revision 8.0
Revised Exhibit A – Transmission Planning Criteria R8 as listed below:
- Expanded description for Section G.1. TAPPING LINE BELOW 100 MW LOAD to emphasize the requirement of a fused bypass arrangement.
- Recreated diagrams throughout for consistency of style.

Details for Revision 9.0
Revised Exhibit A – Transmission Planning Criteria as listed below:
- Added Section C.2.8 – End of life criteria
- Reformatted headers to improve PDF navigation via bookmarks

Details for Revision 10.0
Revised Facility Connection Requirement document to reflect the following:
- Minor clarifications and annual review.
- Section 1 Purpose and Introduction: Added statement regarding applicability of document.
- Section 3.1.9 Voltage, Reactive Power, and power factor control; Generation Facilities subsection:
  - Revised first bullet regarding generator control systems.
  - Added new series of bullets regarding interconnected generation criteria.
- Revised Exhibit A – Transmission Planning Criteria (for details, see Revision History within Transmission Planning Criteria)
VIRGINIA POWER
NORTH CAROLINA POWER

TRANSMISSION PLANNING CRITERIA

Electric Transmission Planning Department
Version 10
Effective 1/15/2015

<table>
<thead>
<tr>
<th>Approved By Name and Title</th>
<th>Signature</th>
<th>Date Approved</th>
</tr>
</thead>
<tbody>
<tr>
<td>J. R. Bailey</td>
<td></td>
<td>01/14/15</td>
</tr>
<tr>
<td>Manager Electric Transmission Planning &amp; Strategic Initiatives</td>
<td></td>
<td></td>
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</table>
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A. Scope and objective

The function of the transmission system is to transport power from generating resources to distribution systems in order to serve the demand of the end-user customers. Reliable transmission system operation implies maintaining continuity of service at sufficient voltage levels without overloading equipment under a wide range of operating conditions. This document provides approved criteria upon which the needs for reinforcements and enhancements to the Dominion transmission systems are determined.

For the purpose of this document, “DVP transmission system” refers to the transmission system owned by Virginia Electric and Power Company, commonly referred to in Virginia as Dominion Virginia Power (DVP), and in North Carolina as Dominion North Carolina Power (DNCP). “Transmission system” refers to networked and radial facilities within the DVP system at voltage levels of 69, 115, 138, 230, and 500 kV.

DVP’s transmission planning criteria ensures adherence to the transmission planning standards of the North American Electric Reliability Corporation (NERC) and those of the SERC Reliability Corporation (SERC), one of the eight regional reliability organizations (RRO) of NERC. Unless noted, the Criteria in this document apply to generation, transmission, and end user facilities.
B. National and regional criteria and guides

B.1. NERC planning standards

The North American Electric Reliability Corporation was established to promote the reliability of the bulk electric systems of North America. NERC coordinates reliability standards for the power systems of the United States, the bordering provinces of Canada, and a portion of Mexico. NERC has developed planning standards to ensure the reliable operation of the interconnected bulk electric systems. These standards can be found at the NERC homepage.

The DVP Transmission Planning Criteria provides a description of how DVP performs simulated testing of the interconnected transmission system to determine its ability to withstand probable and extreme contingencies.

B.2. Regional reliability planning standards

NERC consists of eight regional reliability organizations. DVP is a member of the SERC Reliability Corporation (SERC), one of the eight regional reliability organizations of NERC. DVP plans the bulk electric system (BES) in coordination with PJM, its Transmission Planner (TP), to meet the requirements of NERC and SERC.

B.3. PJM planning standards

The DVP transmission system is integrated into planning and operations of the PJM Interconnections, L.L.C. RTO (PJM). PJM manages a regional planning process for generation and transmission expansion to ensure the continued reliability of the electric system. PJM annually develops a Regional Transmission Expansion Plan (RTEP) to meet system enhancement requirements for firm transmission service, load growth, interconnection requests and other system enhancement drivers. The criteria PJM uses in developing the RTEP is set forth in PJM Manual 14B – PJM Region Transmission Planning Process.
C. Transmission planning, steady-state criteria

C.1. Planning principles and standards

The transmission system must perform reliably for a wide range of conditions. Because system operators can exercise only limited direct control, it is essential that studies be made in advance to identify the facilities necessary to assure a reliable transmission system in future years.

The voltages and equipment loadings on the transmission system should be within acceptable limits, both during normal operation and for an appropriate range of potential system faults and equipment outages. The more probable contingency conditions should not result in voltages or equipment loadings beyond emergency limits. These ‘emergency limits’ can vary based on equipment type and allowable time period.

Table 1A and 1B specify outage events that are analyzed by DVP at the forecasted load levels to determine if any thermal or voltage violations exist. Thermal capability is given with equipment ratings in amps or MVA. Voltage limits are in reference to the nominal design voltage.

Adherence to the criteria given in these tables ensures that DVP’s transmission system meets the applicable reliability requirements of NERC, SERC, and PJM.

System readjustment is allowed when attempting to reduce line loadings or improve voltage profile (only as allowed by NERC Criteria). System readjustments considered in planning analysis include:

- Generation re-dispatch
- Phase angle regulator adjustment
- Load tap changer adjustment
- Capacitor bank switching
- Line switching
- Inductor switching

Loadings on DVP transmission facilities over their normal rating, following a contingency, must be adjusted back down to normal rating within the time frame of the appropriate term emergency rating. Any of the above listed system readjustments are allowable in this situation as DVP employs 8 hour short-term emergency ratings and 15 minute load dump ratings on transmission equipment, which allows sufficient time to implement any adjustments that reduce loadings to the normal rating.

Loadings on facilities over their short-term emergency ratings, following a contingency, must be adjusted back down to the short-term emergency rating within the time frame of the short term emergency rating using the system readjustments listed above.

1 For DVP, phase angle regulator adjustment is used to relieve loadings on the 115kV system in Yorktown and Chesapeake Energy areas. Phase shifting transformers control the division of real power among parallel paths. Chesapeake Energy Center and Yorktown Power Station have phase shifters between the 230 kV and 115 kV systems. The phase shifter transfers load from one voltage level to the other. Phase angle adjustment will be allowed within the parameters noted in PJM’s Manual 14B – PJM Region Transmission Planning Process (RTEP Reliability Planning section).
Nuclear generation re-dispatch will only be considered as a viable mitigation strategy for non-simultaneous contingencies for DVP and only those non-simultaneous contingencies not involving a generating unit for DVP. The required amount of nuclear generation re-dispatch for these types of contingencies should not exceed the maximum output of a single nuclear unit at the site that is required to be reduced. This approach to generation dispatch in response to system events reflects realistic operational constraints associated with nuclear generation and gives consideration to safe operation of the plants. For common mode contingencies, re-dispatch of nuclear generation units is not considered as an option to alleviate potential overload conditions.

If the criteria described in this document cannot be met, mitigation plans are developed. A valid mitigation plan will bring the system into compliance through the most judicious use of a variety of feasible options. These include the development of an operator action plan in conjunction with the use of short term ratings, generation re-dispatch, phase angle regulator adjustments, bus-tie switching, special protection systems, or the installation of a physical reinforcement.

A Special Protection System (SPS), as interpreted from the NERC Reliability Standards Glossary of Terms, is designed to detect abnormal system conditions and take automatic corrective action to provide acceptable transmission system performance. The SPS isolates equipment other than faulted elements and/or reconfigures equipment outside of a zone containing faulted elements. An SPS may be applied as required to address thermal, voltage, or stability issues in accordance with NERC Transmission Planning (TPL) Standards and is subject to the SPS requirements of NERC Protection and Control (PRC) Standards 012 through 017. An SPS does not include automatic restoration to service of un-faulted elements within a faulted zone, under frequency and under voltage load shedding schemes, conventional generator out of step tripping schemes, or remote backup tripping schemes. DVP reviews all existing SPSs periodically and adjusts settings as deemed necessary. DVP primarily installs SPSs as a temporary measure until a more robust solution can be completed to provide acceptable system performance.

Operating steps implemented as part of a special protection system shall be considered, provided that the failure of such system does not result in cascading outages or overloads. For detailed discussion of operator action mitigation plans on the DVP system, see appendix titled Operating Steps.

In addition to those events and circumstances included in Tables 1A and 1B, more severe but less probable scenarios should also be considered for analysis to evaluate resulting consequences. As permitted in the NERC Planning Standards, judgment shall dictate whether and to what extent a mitigation plan would be appropriate.
<table>
<thead>
<tr>
<th>Category</th>
<th>Initial Condition</th>
<th>Event(^1)</th>
<th>Fault Type(^2)</th>
<th>Interruption of Firm Transmission Service Allowed(^4)</th>
<th>Non-Consequential Load Loss Allowed</th>
<th>Dominion Criteria</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>P0</strong></td>
<td>No Contingency</td>
<td>Normal System</td>
<td>None</td>
<td>N/A</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td><strong>P1</strong></td>
<td>Single Contingency</td>
<td>Normal System</td>
<td>Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer(^5) 4. Shunt Device(^6)</td>
<td>3Ø</td>
<td>No(^9)</td>
<td>No(^12)</td>
</tr>
<tr>
<td><strong>P2</strong></td>
<td>Single Contingency</td>
<td>Normal System</td>
<td>1. Opening of a line section w/o a fault (^7)</td>
<td>N/A</td>
<td>No(^9)</td>
<td>No(^12)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>2. Bus Section Fault</td>
<td>SLG</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>3. Internal Breaker Fault (^8) (non-Bus-tie Breaker)</td>
<td>SLG</td>
<td>Yes</td>
<td>Yes</td>
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<td></td>
<td></td>
<td></td>
<td>4. Internal Breaker Fault (Bus-tie Breaker)(^9)</td>
<td>SLG</td>
<td>Yes</td>
<td>Yes</td>
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<tr>
<td><strong>P3</strong></td>
<td>Multiple Contingency</td>
<td>Loss of generator unit followed by System adjustments(^3)</td>
<td>Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer(^5) 4. Shunt Device(^6)</td>
<td>3Ø</td>
<td>No(^9)</td>
<td>No(^12)</td>
</tr>
<tr>
<td><strong>P4</strong></td>
<td>Multiple Contingency (Fault plus stuck breaker(^20))</td>
<td>Normal System</td>
<td>Loss of multiple elements caused by a stuck breaker(^20) (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer(^5) 4. Shunt Device(^6) 5. Bus Section</td>
<td>SLG</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td><strong>P5</strong></td>
<td>Multiple Contingency (Fault plus relay failure to operate)</td>
<td>Normal System</td>
<td>Delayed Fault Clearing due to the failure of a non-redundant relay(^15) protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer(^5) 4. Shunt Device(^6) 5. Bus Section</td>
<td>SLG</td>
<td>Yes</td>
<td>Yes</td>
</tr>
</tbody>
</table>

*Notes*

1. N/A: Not Applicable
2. 3Ø: Three Phase
3. 1Ø: Single Phase
4. Notes: “A” & “B”


\(^3\) Notes: “A” & “B”

\(^4\) Interruption of Firm Transmission Service Allowed: 1. Yes 2. No

\(^5\) Notes: “A” & “B”

\(^6\) Notes: “A” & “B”

\(^9\) Notes: “A” & “B”

\(^12\) Notes: “A” & “B”

\(^7\) Notes: “A” & “B”

\(^8\) Notes: “A” & “B”

\(^9\) Notes: “A” & “B”

\(^10\) Notes: “A” & “B”

\(^11\) Notes: “A” & “B”

\(^12\) Notes: “A” & “B”

\(^13\) Notes: “A” & “B”

\(^14\) Notes: “A” & “B”

\(^15\) Notes: “A” & “B”

\(^16\) Notes: “A” & “B”

\(^17\) Notes: “A” & “B”

\(^18\) Notes: “A” & “B”

\(^19\) Notes: “A” & “B”

\(^20\) Notes: “A” & “B”

---

Table 1A continued on next page
### Table 1A Steady-State Performance PLANNING Events and Dominion CRITERIA (continued)

**HIGH VOLTAGE (HV): 230 kV, 138 kV, 115 kV & 69kV Facilities**

<table>
<thead>
<tr>
<th>Category</th>
<th>Initial Condition</th>
<th>Event$^2$</th>
<th>Fault Type$^3$</th>
<th>Interruption of Firm Transmission Service Allowed$^4$</th>
<th>Non-Consequential Load Loss Allowed</th>
<th>Dominion Criteria</th>
</tr>
</thead>
</table>
| **P6** Multiple Contingency (Two overlapping singles) | Loss of one of the following followed by System adjustments. $^5$
1. Transmission Circuit
2. Transformer $^5$
3. Shunt Device $^6$
4. Single pole of a DC line | Loss of one of the following: 1. Transmission Circuit 2. Transformer $^5$
3. Shunt Device $^6$ | 3Ø | Yes | Yes | Notes “A” & “B” | 90% | 105% |
| **P7** Multiple Contingency (Common Structure) | Normal System | The loss of any two adjacent (vertically or horizontally) circuits on common structure$^{11}$ | SLG | Yes | Yes | Notes “A” & “B” | 90% | 105% |

**Notes for Table 1A**

See separate listing *Table 1 (A & B) Footnotes* for superscript numbered footnotes.

- **Note “A”** - For thermal overloads greater than 100% of Load Dump (LD) rating, system reinforcements will be required.
- **Note “B”** - For thermal overloads less than 100% of Load Dump (LD) rating but greater than 100% of Short Term Emergency (STE) rating, system reinforcements may NOT be required and loss of load up to 300MW is permitted.
- **Percent of Nominal Voltage** (Note: Voltage limits for North Anna and Surry Power Stations are governed by the requirements of their respective Nuclear Plant Interface Requirements (NPIR) with Dominion Electric Transmission as noted in Section E.3).

- **N** – Normal Rating
- **STE** – Short Term Emergency
- **LD** – Load Dump
### Table 1B Steady-State Performance PLANNING Events and Dominion CRITERIA

#### EXTRA HIGH VOLTAGE (EHV): 500kV Facilities

<table>
<thead>
<tr>
<th>NERC Category</th>
<th>Initial Condition</th>
<th>Event</th>
<th>Fault Type</th>
<th>Interruption of Firm Transmission Service Allowed</th>
<th>Non-Consequential Load Loss Allowed</th>
<th>Thermal Limits</th>
<th>Low Voltage Limit **</th>
<th>High Voltage Limit **</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>P0</strong></td>
<td>No Contingency</td>
<td>None</td>
<td>N/A</td>
<td>No</td>
<td>No</td>
<td>94% N</td>
<td>102.5%</td>
<td>107%</td>
</tr>
<tr>
<td><strong>P1</strong></td>
<td>Single Contingency</td>
<td>Normal System</td>
<td>Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device</td>
<td>3Ø</td>
<td>No⁹</td>
<td>No¹²</td>
<td>94% STE</td>
<td>101%</td>
</tr>
<tr>
<td><strong>P2</strong></td>
<td>Single Contingency</td>
<td>Normal System</td>
<td>1. Opening of a line section w/o a fault 2. Bus Section Fault 3. Internal Breaker Fault (non-Bus-tie Breaker) 4. Internal Breaker Fault (Bus-tie Breaker)</td>
<td>SLG</td>
<td>No⁹</td>
<td>No</td>
<td>Notes &quot;C&quot; &amp; &quot;D&quot;</td>
<td>100%</td>
</tr>
<tr>
<td><strong>P3</strong></td>
<td>Multiple Contingency</td>
<td>Loss of generator unit followed by System adjustments</td>
<td>Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device</td>
<td>3Ø</td>
<td>No⁹</td>
<td>No¹²</td>
<td>94% STE</td>
<td>101%</td>
</tr>
<tr>
<td><strong>P4</strong></td>
<td>Multiple Contingency</td>
<td>Normal System</td>
<td>Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section</td>
<td>SLG</td>
<td>No⁹</td>
<td>No</td>
<td>Notes &quot;C&quot; &amp; &quot;E&quot;</td>
<td>100%</td>
</tr>
<tr>
<td><strong>P5</strong></td>
<td>Multiple Contingency</td>
<td>Normal System</td>
<td>Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section</td>
<td>SLG</td>
<td>No⁹</td>
<td>No</td>
<td>Notes &quot;C&quot; &amp; &quot;D&quot;</td>
<td>100%</td>
</tr>
</tbody>
</table>

*Table 1B continued on next page*
Table 1B Steady-State Performance PLANNING Events and Dominion CRITERA (continued)

EXTRA HIGH VOLTAGE (EHV): 500kV Facilities

<table>
<thead>
<tr>
<th>NERC Category</th>
<th>Initial Condition</th>
<th>Event</th>
<th>Fault Type</th>
<th>Interruption of Firm Transmission Service Allowed</th>
<th>Non-Consequential Load Loss Allowed</th>
<th>Dominion Criteria</th>
</tr>
</thead>
<tbody>
<tr>
<td>P7</td>
<td>Normal System</td>
<td>The loss of any two adjacent (vertically or horizontally) circuits on common structure</td>
<td>SLG</td>
<td>Yes</td>
<td>Yes</td>
<td>Notes &quot;C&quot; &amp; &quot;E&quot;</td>
</tr>
</tbody>
</table>

Notes for Table 1B

See separate listing Table 1 (A & B) Footnotes for superscript numbered footnotes.

Note “C” – For thermal overloads greater than 100% of Load Dump (LD) rating on 500kV, system reinforcements will be required.

Note “D” - On 500kV system, for thermal overloads less than 100% of Load Dump (LD) rating but greater than 100% of Short Term Emergency (STE) rating system reinforcements may NOT be required if system adjustments do NOT reduce thermal overloads to less than 100% of Short Term Rating (STE).

Note “E” - For thermal overloads less than 100% of Load Dump (LD) rating but greater than 100% of Short Term Emergency (STE) rating, system reinforcements may NOT be required and loss of load up to 300MW is permitted.

** Percent of Nominal Voltage (Note: Voltage limits for North Anna and Surry Power Stations are governed by the requirements of their respective Nuclear Plant Interface Requirements (NPIR) with Dominion Electric Transmission as noted in Section E.3).

N – Normal Rating

STE – Short Term Emergency

LD – Load Dump
Table 1 (A & B) Footnotes

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.

4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.

5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage apply to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.

6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.

8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.

9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.

11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).
C.1.1. Voltage limits at generating stations

Plant auxiliary power equipment requires adequate voltages in order to maintain reliable operation of online generators as well as to provide for reliable startup capability for offline generators. Minimum transmission voltage limits specific to generating stations, are used to ensure plant auxiliary equipment is provided with adequate voltages during both online and offline operation. These limits apply to all classes of generation except wind turbines, for which the system transmission voltage limits are adequate.

In cases where plant auxiliary power is supplied by power transformers not equipped with a load tap changer (LTC) or equivalent voltage control device, the voltage limits at the low side of the Generator Step-up Unit (GSU) are established as 0.95 per unit (minimum) and 1.05 per unit (maximum) unless otherwise specified by the generator owner.
C.2. Detailed steady-state criteria

C.2.1. System load level

C.2.1.1. Peak period studies

The peak load period must be studied to determine future requirements for the transmission system. The basic references for system peak load to be used in studies for future years are the total corporate system load projection provided by the PJM Load Analysis. The actual peak load in any given future year is likely to be higher or lower than the forecast value. A ‘50/50’ forecast provides a peak load projection with a 50% probability that the actual peak will be higher than the level forecasted in that year.

C.2.1.2. Off-peak period studies

Studies should also be conducted for the purpose of determining risks and consequences at light load or shoulder peak conditions, and for any other period for which system adequacy cannot be evaluated from peak period study results. For these off peak periods, it is assumed that the number of hours of occurrence is substantially higher than the number of hours at or near peak load levels. In addition, severe drought conditions effecting hydro generation plant availability and its impact on the transmission system are also studied.

C.2.2. Power transfers

All studies should consider known firm power transfers affecting the DVP transmission system. This includes known firm transmission service reservations, including those with rollover rights, as well as parallel path power transfers through the system that may impact system reliability.

DVP is part of a larger regional power system that must be capable of withstanding certain levels of power transfers between or through sub areas of the region. PJM conducts load and generator deliverability tests for specific sub areas as part of the Regional Transmission Expansion Plan (RTEP) process to determine whether the system can accommodate these transfers. The DVP transmission system must meet this transfer Load and Generator Deliverability Requirement. A description of the deliverability testing procedures can be found in PJM Manual 14B – PJM Region Transmission Planning Process. SERC Reliability Corporation also performs transfer limit testing to trend the strength of the transmission system. The results of these studies may also indicate a need to increase transfer strength on the DVP system.

DVP routinely tests the capability of the transmission system to transfer reasonable amounts of power (approximately 2000 MW) in excess of firm purchases, sales and transfers, between and among the Company and the neighboring utilities. Such tests are conducted under two basic scenarios: (1) with all transmission facilities in service at or below the maximum continuous normal rating; and (2) with one transmission circuit or transformer out of service while maintaining the loading on all remaining
transmission facilities at or below the maximum continuous emergency rating. Any new facilities connected to the transmission system shall not significantly decrement, the First Contingency Incremental Transfer Capability (FCITC) for transfers between utilities. A FCITC decrement in excess of 5% will be considered significant in most cases.

C.2.3. Equipment ratings

Allowable loadings for transmission facilities are maintained by DVP in an equipment ratings database. In most cases, equipment is given at least a normal rating and one emergency rating. Some equipment is given multiple emergency ratings. These ratings differ by allowable duration, and are referred to as short-term, long-term, and load dump.

The specific procedure used for determining equipment ratings is outlined in the DVP Transmission Facility Ratings Methodology technical reference document.

C.2.4. Circuit breaker interrupting capability

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

Under normal conditions, the current through a circuit breaker shall not exceed the maximum continuous ratings of that breaker. Further, a circuit breaker shall have sufficient capability to interrupt a close-in single phase fault or three phase-to-ground fault.

C.2.5. Reactive power planning

The objective of system reactive power planning is to efficiently coordinate the reactive requirements of the transmission and distribution systems to satisfy voltage criteria. Meeting this objective ensures voltage stability, provides generator auxiliary power systems on the distribution system with adequate voltage, and minimizes transmission losses and reactive interchange. System reactive requirements can be controlled by changing generation excitation, operating synchronous condensers, changing transformer tap positions, switching transmission and distribution level static capacitors, switching shunt reactors, and adjusting solid-state reactive compensation devices (SVCs, etc.).

The DVP system is planned so that transmission voltages will be maintained within an acceptable range for normal and emergency conditions as described in Tables 1A and 1B.

Low transmission voltage will lead to undesirable effects in both the transmission and distribution systems, such as higher losses, reduced insulation life, and reduced effectiveness of capacitors. These effects would also increase the difficulty in recovering from low transmission voltage situations. The outage events analyzed to assess voltage
adequacy are the same as those listed in Tables 1A and 1B. Distribution facilities which are maintaining power factors at the Transmission Point of Interconnection (POI) that are less than PJM’s requirement (per Manual 14B – PJM Region Transmission Planning Process) and DVP’s requirement (97.3% lagging) may not be able to maintain satisfactory voltage to customers served from these distribution facilities when transmission system voltages are at or near the lower voltage limits of normal and emergency transmission system operations.

Conversely, high transmission voltages that exceed operating voltage schedules can stress generation, distribution, and transmission equipment and lead to premature fatigue or even failure.

C.2.6. **Radial transmission lines**

A Radial transmission line is defined as a single line that originates in a substation, serves load and does NOT tie to any other transmission line or substation. Unlike load served from a network transmission line having two sources where a downed conductor or structure can be sectionalized for load to be served before repairs are completed, load served from a single source radial transmission line cannot be reenergized until all repairs to the line are completed. Accordingly, loading on single source radial transmission lines will be limited to the follow:

- 100 MW Maximum
- 700 MW-Mile Exposure (MW-Mile = Peak MW X Radial Line Length)

Once a radial loading limit exceeds any of these thresholds, an additional transmission source is required. Acceptable transmission source includes but is not limited to the following:

- Network from a separate transmission substation source (Preferred)
- Loop back to same transmission substation source
- Normally open network or loop transmission source

C.2.7. **Network transmission lines – Limitations on direct-connect loads**

A network transmission line is defined as one that connects two network transmission substations (connect to other lines & substations) and a “Tap point” is defined as a direct connection of a customer to a network transmission line without addition of any transmission breaker or breakers to split the line. Network transmission lines facilitate network flows and could serve directly connected (Tapped) loads. In Dominion system 500, 230, 138, 115 and 69kV lines are considered transmission and all with the exception of 500kV could be tapped to serve customer load.

In general, the number of direct-connect loads (tapped facilities) should be limited to four (4); however, good utility practice and sound engineering judgment must be exercised in application of this criteria.
C.2.8. End of life criteria

Electric transmission infrastructure reaches its end of life as a result of many factors. Some factors such as extreme weather and environmental conditions can shorten infrastructure life, while others such as maintenance activities can lengthen its life. Once end of life is recognized, in order to ensure continued reliability of the transmission grid, a decision must be made regarding the best way to address this end-of-life asset.

For this criterion, “end of life” is defined as the point at which infrastructure is at risk of failure, and continued maintenance and/or refurbishment of the infrastructure is no longer a valid option to extend the life of the facilities consistent with Good Utility Practice and Dominion Virginia Power Transmission Planning Criteria. The infrastructure to be evaluated under this end-of-life criteria are all transmission lines at 69 kV and above.

The decision point of this criterion is based on satisfying two metrics:

1) Facility is nearing, or has already passed, its end of life, and
2) Continued operation risks negatively impacting reliability of the transmission system.

For facilities that satisfy both of these metrics, this criterion mandates either replacing these facilities with in-kind infrastructure that meets current Dominion standards or employing an alternative solution to ensure the Dominion transmission system satisfies all applicable reliability criteria.

Dominion will determine whether the two metrics are satisfied based on the following assessment:

1. End of Life

Factors that support a determination that a facility has reached its end of life include, but are not limited to,

- **Condition** of the facility, taking into consideration:
  - Industry recommendations on service life for the particular type of facility
  - The facility’s performance history
    - Documented evidence indicating that the facility has reached the end of its useful service life
  - The facility’s maintenance and expense history
- **Third-party assessment** - While not required, Dominion has the option of seeking a third-party assessment of a facility to determine if industry specialists agree the facility has reached the end of its useful service life
2. Reliability and System Impact

The reliability impact of continued operation of a facility will be determined based on a planning power flow assessment and operational performance considerations. The end-of-life determination for a facility to be tested for reliability impact will be assessed by evaluating the impact on short and long term reliability with and without the facility in service in the power flow model. The existing system with the facility removed will become the base case system for which all reliability tests will be performed.

The primary four (4) reliability tests to be considered are:

1. NERC Reliability Standards
2. PJM Planning Criteria – As documented in PJM Manual 14B – PJM Region Transmission Planning Process
3. Dominion Transmission Planning Criteria contained in this document
4. Operational Performance – This test will be based on input from PJM and/or Dominion System Operations as to the impact on reliably operating the system without the facility

Additional factors to be evaluated under system impact may include but not be limited to:

1. Market efficiency
2. Stage 1A ARR sufficiency
3. Public policy
4. SERC reliability criteria

Failure of any of these reliability tests, along with the end-of-life assessment discussed herein, will indicate a violation of the End-of-Life Criteria and necessitate replacement as mandated earlier in this document.

After the end of service life and reliability impact of a facility are evaluated and it has been determined that the facility violates the End-of-Life Criteria, a determination will be made as to whether replacement of the facility is the most effective solution for an identified reliability need, or whether an alternative solution should be employed. This determination will be made based on the results of an additional planning power flow assessment evaluating alternatives to resolve the identified violations of the reliability tests described above. The following factors will be considered in determining whether to proceed with facility replacement or with an alternative solution:

- Effectiveness of the alternative as compared to the replacement facility
- Constructability comparison
- Cost comparison
D. Transmission planning, system stability criteria

D.1. Introduction

There are many different variables that affect the results of a stability study. These factors include:

- pre-fault and post-fault system configuration
- system load level and load characteristics
- generation dispatch patterns and unit dynamic characteristics
- type and locations of system disturbances
- total fault clearing time(s)
- the amount of flow interrupted as a result of switching out a faulted element
- level of detail and accuracy of available models/data
- proximity to other generating units

Many of these factors change in the operating arena on a continuous basis. Every effort should be made to evaluate the most severe, yet credible/probable combinations of line/faults/equipment failures in planning arena. If the system operating condition is known a couple of days in advance of any scheduled maintenance outage, a more accurate assessment/analysis can be performed which could be more restrictive or less restrictive than the ones studied in planning arena.

D.2. General criteria

The criteria for performing stability simulations near generating stations on Dominion Virginia Power (DVP) system supports PJM in its role as Transmission Planner (TP).

For breaker failure backup clearing, it will be assumed that only one pole fails to operate where three separate mechanisms (independent poles) are available as in the case of all 500 kV breakers on DVP system. Stability analysis is not required for units that are not part of the Bulk Electric System (BES) as defined by NERC. In general, generators rated 20 MVA or less in size and with aggregate plant capacity less than or equal to 75 MVA are not part of the BES. The results of stability studies are generally valid for about 15 to 20 seconds following a disturbance. Therefore, disturbance simulations will be carried out to 15 to 20 seconds. The transformer taps are fixed at the pre-disturbance level throughout the simulations since the tap movements take more than 30 seconds.
D.3. Study horizon

Generally, stability studies are performed for the near-term horizon (1-5 years) since the required corrections, if and when warranted, are generally of the following types and can be implemented in a relatively short period of time:

- Shorten the fault clearing time(s) by resetting breaker failure timer(s), replacing relays, or replacing circuit breakers
- Add dual primary protection schemes to mitigate delayed clearing
- Add or tune a power system stabilizer (PSS)
- Apply special protection system (SPS)
- Add out-of-step (OOS) protection
- Install series capacitors
- Establish operating restrictions for a contingency period of short duration covering forced or maintenance outages.

There are several other reasons stability studies concentrate in the near-term horizon. The system representation (load, generation, etc.) in study base cases for a long-term horizon (6-10 years) is inherently uncertain from a dynamics perspective. Some of the future generation in these cases may not materialize and hence may yield erroneous results indicating either unnecessary improvements or a false sense of security. A large number of merchant plants have been delayed or cancelled altogether in the past. The delays or cancellations of such merchant plants require re-studies. The further one goes out in study time horizon, the possible combinations of such uncertainties multiply. Since stability studies are very time consuming, extensive long-term studies become impractical. SERC has recognized this and has acknowledged in its supplement that stability studies for a longer-term planning horizon are not required for full compliance except for new generation that falls into the long-term study horizon.

For identified stability problems that cannot be remedied with the aforementioned solutions, i.e., the probability of the operating condition and/or contingency occurring is deemed high, new transmission infrastructure may be required to ensure stability for safe and reliable operation of the electric grid. In cases where a near-term horizon stability study indicates a potential correction that may require much longer lead time, such as requiring a new transmission line, or if a Generation Interconnection request is for a long-term horizon, the long-term stability study would then be performed.

D.4. Study cycle

It is not practical to perform dynamic simulations for all generating plants every year for all categories listed in Table 1 of the TPL Standards. Therefore, PJM will perform simulations to cover all generating plants over a three-year study cycle unless changing system conditions warrant a shorter interval. In case of a new generation addition or a capacity addition to an existing plant, it should be properly studied prior to its in-service date. Stability analysis in such cases will first be performed by PJM as the Generation Interconnection queue administrator. DVP will review the results of PJM stability analysis and perform any subsequent analysis, if and when deemed necessary.
D.5. **Dynamics data collection**


Dominion Electric Transmission Planning is responsible for submitting dynamic data to PJM for Transmission Owner equipment with dynamic characteristics such as SVCs and STATCOMs.

D.6. **Selection of a reference power flow case**

Planning arena studies for stability analysis are performed using an estimated snap-shot of the expected system operating conditions for the study period selected. The power flow base cases that match dynamics data for the Eastern Interconnection are prepared by the Multi-regional Modeling Working Group (MMWG) for selected years on an annual basis. The dynamically reduced SERC cases are prepared using three of the MMWG cases, generally every other year. The internal DVP power flow base cases are updated on a regular basis to incorporate the most updated information on facility ratings/upgrades, load, etc.

It is a general practice to incorporate the DVP system representation from the most updated internal base case for the study year into one of the SERC reduced base cases depending on the study year. A validation review is then performed on the combined case to make sure that the stability case thus prepared initializes error free and a 30-second “Drift Run” is performed to insure that the steady-state stability is maintained. This is steady-state condition, NERC TPL-001, Category P0.

D.7. **Selection of generation dispatch**

The economic dispatch used in internal power flow base cases may not be particularly useful in stability analysis because it may not stress the system enough in the study area. The intent of a stability study is to find credible worst case scenarios, keeping the study purpose in mind, for which stability may not be maintained. For example, if new generation is added in the middle of an existing transmission line, the generation may split evenly between the two outlets from the new plant using the generation dispatch modeled in a reference base case. For this generation dispatch, the stability may be maintained for any conceivable fault scenarios. However, in practice, there could be other operating scenarios when one of these lines connected to the plant may carry more of the new plant output than the other line. Contingencies involving this heavily loaded line may adversely impact stability as compared to generation dispatches modeled in the base case.

Also, the unit generation in a reference base case (Pgen) may not represent the maximum unit output possible (Pmax) and may need to change depending on the study area. In general, a stability study is performed at the maximum MW capability of the unit under study regardless of the season and at leading power factor at the low side of GSU provided that equipment voltage limits are not violated; i.e., the units are dispatched such that they are absorbing 50% of their minimum reactive capability (Qmin) without violating the terminal voltage criteria of 0.95 pu. Sound engineering judgment is applied in selecting generation dispatch for a stability case since more than one dispatch scenario may need to be studied.
D.8. Selection of contingencies

In general, contingency simulations are based on Table 1 of NERC Reliability Standard TPL-001-4. However, all contingencies may not be applicable in a given study due to either breaker arrangement or type of protection scheme employed. Also, if the stability is maintained for a more severe fault condition (e.g. three-phase or two-phase-to-ground), it is not necessary to simulate a fault of less severity (e.g. single-phase-to-ground). If identical equipment is removed from service due to a fault at various locations in a substation, leaving identical post-fault/post-switching system condition, it is not necessary to apply the fault at more than one of such locations. Much depends on the type of station equipment, station arrangement and type of protection schemes applied at a given location.

As for simulating transmission line faults, if there are only two lines from a plant, both should be tested using different power flow cases with different dispatch patterns (see Selection of Generation Dispatch above), faulting the line with highest flow in each case. For a multiple line station, the line carrying the highest power should be the first one to be selected and the remaining lines(s) should be selected based on system experience and sound engineering judgment. In case of any doubt, faults on all lines may need to be simulated. If stability is maintained for a more severe fault scenario (e.g. 3-phase fault), a less severe fault scenario (e.g. SLG) need not be simulated everything else remaining same.

If a line length is short, it may be necessary to check contingencies at the next station. For breaker-failure scenarios, contingencies are selected that would simulate the weakest system condition based on station breaker arrangement and system knowledge. If the failed breaker would trip a generating unit(s) due to breaker arrangement, that contingency may be omitted depending on the results of more severe contingencies.

The voltage stability analysis shall first be performed by power flow studies. Once potential voltage instability problem is identified in a power flow study (or observed in the field), a time-domain analysis shall then be performed for confirmation and mitigation of the problem.

D.9. What to look for in study results

Checks are performed to make sure all on-line units initialize properly without any error messages. A 30-second “drift run” should be performed prior to any stability analysis to ensure successful initialization. This corresponds to the steady-state condition defined as Category “P0” in Table 1 of NERC TPL-001.

Checks are performed to make sure the system is stable with acceptable voltages for selected contingencies, and the damping ratio is 3% or better for inter-area oscillations and 4% or better for local mode oscillations. Solutions identified in section D3 are considered for situations where transient voltage or oscillation damping is not met, or if transient stability is not maintained. If the inter-area oscillations have an unacceptable damping ratio and other entities’ units are found to be participating significantly, then it may require a joint study between the affected parties. Power system stabilizers are recommended, especially if oscillation damping criteria is marginally satisfied. N-1-1 contingencies with no redispatch are considered to ensure transient stability is maintained with positive damping. This provides a safety margin for any planned conditions and/or unexpected contingencies that could occur. If the oscillation damping is positive but does not meet the criteria above, operation restriction may be applied to ensure sufficient oscillation damping for both local and inter-area modes of
oscillations. Generator out-of-step (OOS) protection is highly recommended on all BES generating units to ensure the protection and safety of the generator itself.

For system conditions and selected contingencies that results in generator transient instability, additional analysis is performed to quantify the risk of cascading events and potential for blackout conditions. Cascading failure analysis will consider a risk-based study of the loss of the generating unit based on expected protection and control as well as unexpected tripping. Depending on the size and expanse of the affected area, other solution options, operating restrictions, or transmission investments may be considered.

Since the transmission planning studies are performed for an estimated operating condition for a future date, the post disturbance thermal loading and voltage levels may vary widely when real disturbance occurs. This is because the load, generation dispatch and available reactive resources in real time may be quite different than the ones studied in planning arena. For this reason, the thermal limits and voltage conditions should be checked using the real-time contingency analysis tool.

D.10. Implementation procedure

Stability analysis may warrant corrections or additional requirements in order to meet the stability criteria listed in this document. The implementation procedure for such items depends on the type of corrections warranted and the nature of installation. The following is a general guideline for Transmission Planning to get such fixes implemented.

D.10.1. For existing installations

- Corrections related to transmission fault clearing times near generating stations that can be resolved by changes to existing relay set points shall be communicated to Electric Transmissions Circuit Calculations group for implementation. PJM should also be informed as to the results of this analysis.
- A Capital project shall be generated for corrections related to transmission fault clearing times near generation stations that require baseline improvements such as new or additional equipment. All Capital projects shall first be validated, approved and assigned cost and construction responsibility by the PJM Regional Transmission Expansion Planning (RTEP) process.
- Output restrictions and/or unit trip(s) for the next pending contingency condition indentified by DVP in routine planning studies, will be communicated to the SOC. In turn, the SOC shall inform PJM for implementation as appropriate.
- In case of scheduled maintenance or construction outages, the results/recommendations shall be conveyed to the person through whom the stability analysis request came to the stability engineers. For example, if a Project Manager requests such analysis to the load Planning Engineer, the stability engineer shall forward his analysis to the load Planning Engineer. If SOC requests such analysis, the results/recommendations shall be forwarded to SOC which in turn shall inform PJM for implementation as appropriate.
D.10.2. For new installations or capacity additions

New generating resources are studied as part of the PJM Generation Interconnection Queue process. PJM shall document the fault clearing time requirements and/or any additional protection requirements in its Impact Study report. PJM shall also communicate the requirements on the generation side to the GO requesting the Interconnection in PJM Queue. For the transmission related requirements, Dominion shall communicate these to the Substation Engineering group for design and implementation.
E. Nuclear plant interface coordination

E.1. Introduction

Nuclear power plants have special needs for backup station service not found in other plants. In order to safely shut down a nuclear unit, the station service must have an adequate supply of power under tight voltage tolerances to the safety systems. Although nuclear plants have diesel generators as a backup supply, their preferred power source is the transmission grid. This allows multiple levels of redundancy which is the hallmark of the nuclear plant’s endeavor to the highest level of safety.

E.2. NRC regulations

The Federal Nuclear Regulatory Commission (NRC) lays out certain regulations on the design and operation of Nuclear Plants. Appendix A of Regulation 10 CFR 50 “General Design Criteria for Nuclear Power Plants” states:

“Criterion 17–Electric power systems. An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.”

The above regulation General Design Criterion 17 is often abbreviated “GDC-17.”
E.3. Design requirements

PJM and Dominion Electric Transmission Planning will design the system to meet the GDC-17 requirements. In order to provide adequate voltage to safety systems, the Nuclear group periodically provides Nuclear Plant Interface Requirements (NPIR) to Dominion Electric Transmission. The NPIR tables shown below are for reference only and are subject to change. Steady state voltage limits will use the “Emergency Limit Low” and “Emergency Limit High” voltage limits listed below for contingency studies.

### North Anna NPIR Limits

<table>
<thead>
<tr>
<th>Bus Name</th>
<th>Normal Limit Low</th>
<th>Emergency Limit Low</th>
</tr>
</thead>
<tbody>
<tr>
<td>500 kV</td>
<td>510.0 kV (1.02 pu)</td>
<td>505.0 kV (1.01 pu)</td>
</tr>
<tr>
<td>230 kV</td>
<td>226.3 kV (0.984 pu)</td>
<td>224.0 kV (0.974 pu)</td>
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</table>

<table>
<thead>
<tr>
<th>Bus Name</th>
<th>Normal Limit High</th>
<th>Emergency Limit High</th>
</tr>
</thead>
<tbody>
<tr>
<td>500 kV</td>
<td>535.5 kV (1.071 pu)*</td>
<td>540.0 kV (1.08 pu)*</td>
</tr>
<tr>
<td>230 kV</td>
<td>239.2 kV (1.04 pu)</td>
<td>242.0 kV (1.052 pu)*</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Bus Name</th>
<th>Normal Voltage Drop</th>
<th>Emergency Voltage Drop</th>
</tr>
</thead>
<tbody>
<tr>
<td>500 kV</td>
<td>3.5 %</td>
<td>3.5 %</td>
</tr>
<tr>
<td>230 kV</td>
<td>3.5 %</td>
<td>3.5 %</td>
</tr>
</tbody>
</table>

### Surry NPIR Limits

<table>
<thead>
<tr>
<th>Bus Name</th>
<th>Normal Limit Low</th>
<th>Emergency Limit Low</th>
</tr>
</thead>
<tbody>
<tr>
<td>500 kV</td>
<td>510.0 kV (1.02 pu)</td>
<td>505.0 kV (1.01 pu)</td>
</tr>
<tr>
<td>230 kV</td>
<td>222.3 kV (0.967 pu)</td>
<td>220.0 kV (0.957 pu)</td>
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</table>

<table>
<thead>
<tr>
<th>Bus Name</th>
<th>Normal Limit High</th>
<th>Emergency Limit High</th>
</tr>
</thead>
<tbody>
<tr>
<td>500 kV</td>
<td>530.0 kV (1.06 pu)</td>
<td>535.0 kV (1.07 pu)</td>
</tr>
<tr>
<td>230 kV</td>
<td>239.2 kV (1.04 pu)*</td>
<td>242.0 kV (1.052 pu)*</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Bus Name</th>
<th>Normal Voltage Drop</th>
<th>Emergency Voltage Drop</th>
</tr>
</thead>
<tbody>
<tr>
<td>500 kV</td>
<td>4.5 %</td>
<td>4.5 %</td>
</tr>
<tr>
<td>230 kV</td>
<td>6.0 %</td>
<td>6.0 %</td>
</tr>
</tbody>
</table>

*Normal Limit High and Emergency Limit High are more restrictive than the GDC-17 analysis due to Electric Transmission voltage limits.

Only the following contingency scenarios will be evaluated for either North Anna or Surry using the NPIR’s above.

### North Anna or Surry Contingency Scenarios

<table>
<thead>
<tr>
<th>Transmission Condition</th>
<th>Unit 1</th>
<th>Unit 2</th>
</tr>
</thead>
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Because emergency systems require adequate voltage immediately following an event, transmission LTC’s should be locked post-contingency.

For violations of the NPIR’s listed above, the transmission planner will contact the GDC-17 coordinator for Electric Transmission Planning. PJM/Dominion Electric Transmission Planning will notify Dominion Nuclear of any NPIR criteria violations. Transmission study criteria violations based on standard PJM/Dominion criteria testing will be handled by the procedures described in the PJM agreements and manuals. For study violations that are beyond applicable PJM criteria, Dominion Nuclear will determine if any further action is required and respond to Dominion Electric Transmission Planning. Dominion Electric Transmission Planning will work with PJM to resolve concerns identified by Dominion Nuclear.

For contingencies more severe than those listed above, standard planning voltage range criteria will be applied.

E.4. Underfrequency studies

The underfrequency load shed program (UFLS) should be designed to coordinate with station underfrequency trip settings. The North Anna reactor coolant pump (RCP) is set to trip at 56.55 Hz with a time delay of 100 milliseconds. The Surry reactor coolant pump (RCP) is set to trip at 58.05 Hz with a time delay of 100 milliseconds.

E.5. Angular stability studies

Angular stability studies are performed on nuclear plants using the standard methodology used for any synchronous machine. The results of these studies should be forwarded to Nuclear Engineering.

E.6. System analysis protocol

The Nuclear Switchyard Interface Agreement System Analysis Protocol (CO-AGREE-000-IA1-4 or its successor) outlines the types and frequency of studies which may be performed in support of the nuclear plant. It also specifies the type of communications necessary and the frequency of the analysis. In order to show compliance with NERC Standard NUC-001-2 (or its successor), the GDC-17 coordinator shall retain evidence of communications with the appropriate nuclear contacts.

E.7. Changes to the system

The NERC standard NUC-001-2, R8 states that the “...Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.” Transmission Planning should assess the actual and proposed changes for possible impacts to the Nuclear Plant. If no changes are judged to impact the NPIR’s, Planning should make a transmittal to Nuclear Engineering stating that fact for documentation of compliance with the NERC standard.
F. Transmission line connections - generation

F.1. Single circuit interconnections to a transmission line

A transmission line tap as shown in Diagram F.1 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. However, final System Protection requirements along with interconnection substation requirements shall be based on the reliability impact conducted through the PJM Interconnection Queue process as defined in PJM Manual 14C – Generation & Transmission Interconnection Facility Construction. The customer should reserve property for construction of the Dominion-owned interconnection station.

Diagram F.1: Line Tap – Generation adjacent to transmission line
F.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 Diagram F.2.A or F.2.B 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. However, final System Protection requirements along with interconnection substation requirements shall be based on the reliability impact conducted through the PJM Interconnection Queue process as defined in PJM Manual 14C – Generation & Transmission Interconnection Facility Construction.

Diagram F.2.A: 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 Diagram F.2.B. This arrangement can have its advantages since acquiring land and permitting a new station at the tap point would not be required. The customer should reserve property for construction of the Dominion owned interconnection station.

**Diagram F.2.B: Looped Tap – Large generation located remote from transmission line**

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**F.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.

**F.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 four breaker or less ring bus are acceptable. If more than a four breaker ring bus is required, a breaker and a half arrangement would be used for reliability considerations.
F.5. Generation interconnection breakers

A customer owned interconnection breaker is required if the generating station is located remote from the interconnection station (See Diagrams F.2.A and F.2.B). 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 Diagram F.5.A or multiple breakers can be used as in Diagram F.5.B.

Diagrams F.5.A and F.5.B – Multiple breakers

Diagram F.5.A.  
Diagram F.5.B.

However, regardless of distance, final System Protection requirements along with interconnection substation requirements shall be based on the reliability impact conducted through the PJM Interconnection Queue process as defined in PJM Manual 14C – Generation & Transmission Interconnection Facility Construction.
G. Load criteria – End user

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 MW
- Locations remote from distribution facilities
- Remote locations where distribution facilities are not adequate
- Loads with nonstandard voltage requirements
- Loads having large surge requirements

The following are preferred minimum load levels within the ten year planning horizon for the direct interconnection of loads to existing transmission lines:

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

The interconnection of loads below these levels will be permitted after a thorough planning analysis concludes that the cost and reliability of distribution alternatives are clearly inferior to the overall cost and reliability of a transmission interconnection which includes, without limitation, considerations of any transmission reliability or operational concerns that may arise from adding the transmission interconnection. For consideration of an interconnection of loads below the specified levels, the requesting party shall prepare documentation explaining and supporting why distribution alternatives are inferior and must supply additional documentation which may require Dominion to undertake its own analysis.

The feasibility of serving customers direct from the transmission along with determining the final recommended transmission interconnection facilities requires a comprehensive study and coordination. Factors to be considered prior to agreeing on a customer connection are as follows:

- Economics of Distribution versus Transmission alternates
- Customer parallel generation
- Transmission line tap or loop length
- Economics of radial line versus looping even when typical thresholds (e.g., length, load level) are not met
- Mitigation of economic risk in the event actual load varies materially from planned load
- Customer transformer characteristics
• Customer switching
• Effect on protective relaying at remote terminals
• Problems of large through power on looped lines
• Extent of customer facilities

In general, a tap line in excess of one mile shall require a terminal station. If the tap line is long enough to require a terminal substation, a three-breaker or four-breaker ring bus may be required. With these arrangements, loss of line to the customer does not interrupt flow on the transmission system and loss of a transmission line does not result in loss of service to the customer. The total projected load and MW-Mile$^2$ exposure are also factors to be taken into consideration. The final number of breakers and breaker arrangement will however be based on the specific interconnection request and reliability impact on transmission system.

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

**G.1. Tapping line for loads below 100 MW**

**Diagram G.1.A: Tap line for less than 100MW, less than 1 mile**

A transmission line tap as shown in Diagram G.1.A can generally be used to interconnect a proposed customer facility located within one mile or less to the nearest transmission line. With this arrangement, company will install necessary system protection equipment and associated components at the customer’s facility. The final System Protection and interconnection substation requirements communicated to the customer shall be based on the site-specific detailed reliability impact as determined by Dominion.

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2 Total length of the line in miles times the total projected load in MW. See Section C.2.6 Radial transmission lines for details.
A transmission line tap as shown in Diagram G.1.B can generally be used to interconnect a proposed customer facility located more than one mile from to the nearest transmission line. A three-breaker or four-breaker ring bus may be required. With this arrangement, company will install all necessary equipment at the interconnection substation at or near the transmission line. The final System Protection and interconnection substation requirements communicated to the customer shall be based on the site-specific detailed reliability impact as determined by Dominion.
A transmission line tap as shown in Diagram G.1.C can generally be used to interconnect a proposed customer facility of less than 100 MW and when it is more economical to build double circuit rather than a single line. Addition of breaker “C” may be required based on detailed System Protection and interconnection substation assessments conducted by Dominion. The customer may reserve property for the Dominion owned interconnection station if one is required.
G.2. Tapping lines for loads 100 MW and greater

The addition of customer load in excess of 100 MW should be connected to the Company’s transmission system as shown in Diagrams G.2.A and G.2.B below. If available 230kV is the preferred voltage level to connect loads greater than 100MW. The addition of a second customer transformer (dotted red transformer in drawings below) requires the installation of an additional breaker (“C” in drawings below).

Diagram G.2.A: Tapping line 100 MW load and greater, less than a mile

A transmission line tap as shown in Diagram G.2.A can generally be used to interconnect a proposed customer facility of 100 MW and greater (Minimum of a 3-breaker ring bus feeding one transformer and a 4-breaker ring bus when connecting two transformers). With this arrangement, loss of line to the customer does not interrupt flow on the transmission system and loss of a transmission line does not result in loss of service to the customer. However, the final System Protection and interconnection substation requirements communicated to the customer shall be based on the site-specific detailed reliability impact as determined by Dominion. The customer could reserve property for construction of the Dominion-owned interconnection station if customer parcel is adjacent to or in very close proximity of transmission right of way.
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 customer station as shown in Diagram G.2.B. (Minimum of a 3-breaker ring bus feeding one transformer and a 4-breaker ring bus when connecting two transformers). This arrangement can have its advantages since acquiring land and permitting a new station at the tap point would not be required. The customer should reserve property for construction of the Dominion owned interconnection station.
G.3. Prohibited arrangements and allowable alternatives

The Company does not allow by-pass switches around primary interrupting devices on the customer’s distribution transformer at the point of interconnection as shown in Diagram G.3.A. The Company’s current system protection principles require that each system element, (line, transformer, bus, etc) have primary relay protection in service at all times when the element is energized and placed in service. This ensures that all elements have adequate protection for safe and reliable operation of the transmission system and are ready to remove the element from service should a fault occur. This is even more critical in cases like distribution tapped transformers where upstream line protection cannot provide backup coverage. The use of an air-break bypass switch would expose customer’s personnel and equipment in an unprotected zone. This places risk to the Bulk Electric Systems integrity as well as impacting all other customers served by the same transmission line.

Diagram G.3.A: Prohibited by-pass switch
Allowable Sample Alternatives: A parallel circuit switcher arrangement as shown in Diagram G.3.B provides a fully redundant capability. Another approach is the fused bypass as depicted in Diagram G.3.C. The exact design, system protection configuration and operating arrangement may be customized as necessary, subject to review and approval by both the Company and the Customer.

Diagram G.3.B: Allowable sample alternative with interrupting devices

Diagram G.3.C.: Allowable sample alternative with fused bypass
G.4. Tapping Company’s bus

In those cases where it may be practicable to tap an existing transmission substation bus to serve a customer, Diagram G.4 indicates the typical facilities arrangement for normal service:

**Diagram G.4: Tapping existing substation bus below 100 MW load**

The following are preferred minimum load levels within the ten year planning horizon for the direct interconnection of loads to the existing substation busses:

- 230 kV – 75 MW
- 138 kV – 50 MW
- 115 kV – 50 MW

The requirements for direct interconnection to company’s transmission bus will be determined on case by case basis.
H. References

- NERC Planning Standard TPL-001
- Transmission System Performance SERC Supplement
- NERC Reliability Standard NUC-001
- Nuclear Switchyard Interface Agreement CO-AGREE-000-IA1
- Nuclear Switchyard Interface Agreement System Analysis Protocol CO-AGREE-000-IA1-4
- PJM Manual 39 – Nuclear Plant Interface Coordination
- Manual 14B – PJM Region Transmission Planning Process

I. Abbreviations & definitions

- AAR - Auction Revenue Rights (see PJM Manual 06 – Financial Transmission Rights for more details)
- ANSI - American National Standards Institute
- ERAG - Eastern Interconnection Reliability Assessment Group
- FCITC - First Contingency Incremental Transfer Capability
- GSU - Generator Step-up Transformer
- IEEE - Institute of Electrical and Electronic Engineers
- MMWG - Multi-Regional Modeling Working Group
- NERC - North American Electric Reliability Corporation
- POI - Point of Interconnection
- RTO - Regional Transmission Organization
- PSS - Power System Stabilizer
- SERC - SERC Reliability Corporation
J. Revision History

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*For these revisions, the planning guideline was an attachment within the DVP facilities connection requirements document. Associated comments for these revisions do not necessarily apply to the contents of the planning guideline specifically.

**Details for Revision 1.0**
- Revised to include information regarding Dominion’s generation interconnection procedures/process

**Details for Revision 2.0**
- 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.

**Details for Revision 3.0**
- Revised to reflect the following:
  - Updates to NERC Reliability Standards
  - Dominion’s PJM Membership
  - References to new SERC regional studies processes

**Details for Revision 4.0**
- Revised to reflect the following:
  - PJM Generation Queue Changes Section 4
  - General Revisions all sections

**Details for Revision 5.0**
- Revised the following:
  - Section 2.12: Clarified content regarding synchronizing of facilities.
  - Exhibit A: Changed loading criteria to not exceed emergency rating of transmission facility.
  - Various errata changes.
Details for Revision 6.0
- Overhaul and expansion of entire Planning Criteria.
- Document previously called "Transmission Planning Guidelines"

Details for Revision 7.0
- Updated to include future reference to TPL-001-4 (R1 and R7 NERC enforcement date of 01-01-2015)
- Updated titles for approval process
- Various errata changes

Details for Revision 8.0
- Expanded description for Section G.1. TAPPING LINE BELOW 100 MW LOAD to emphasize the requirement of a fused bypass arrangement.
- Recreated diagrams throughout for consistency of style.

Details for Revision 9.0
- Added section C.2.8 - End of life criteria
- Reformatted headers to improve PDF navigation via bookmarks.

Details for Revision 10.0
- Clarifications and annual review.
- Reformatted approval area and moved to title page.
- Reformatted Revision History and moved to end of document (Section J).
- Modified throughout to reflect NERC Reliability Standard TPL-001-4, including replacement of Tables 1A and 1B and deletion of “Category D Multiple Testing Requirements” (previously Section C.2.7 in Revision 9.0 document).
- Section C.2.6 Radial lines: Expanded to introduce new criteria and metrics.
- Section C.2.7 Network transmission lines – Limitations on direct-connect loads: Inserted new section.
- Section D.4 Study cycle – Clarified that PJM (not DVP) performs simulations to cover all generating plants over a three-year study cycle (not five-year).
- Section G: Modified electrical arrangements and clarified lines of demarcation.
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 [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:  Author. 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 FACILITIES DATA:
New Delivery Point Voltage: ____________________________________________
New Peak kVA Capacity of Delivery Point Facilities: __________________________
Peak kW and kVAR During First Three Years Following Implementation and Highest Peak Within Ten Years:

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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:  
[6] Protection Device information (including device types, serial and model numbers, relay settings, etc.)
**SECTION IV – TIMING**

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**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