Note: This document contains FAC-001-3 and FAC-002-3. FAC-001-3 – Facility connection requirements is in the first part of the document. FAC-002-3 – Facility Interconnection Studies begins on page 20.

Oklahoma Gas and Electric Co.

Facility Connection Requirements

MAINTAINED BY

Transmission Planning Engineering Department

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Preface: This Facility Connection Standard applies to any connection to the electric system within the OG&E regardless of voltage. Additional requirements apply for load additions of 20,000 kVA (20 MVA) or greater. Separate requirements apply to generation.

Transmission and Generation Facility Interconnections:

OG&E is a member of the Southwest Power Pool (SPP) Regional Transmission Organization (RTO), and therefore is subject to SPP RTO Criteria and Transmission Tariff requirements which address certain requests for transmission, generation and delivery point (including end-user) interconnections:

- Transmission interconnections that involve two or more SPP members or a SPP member and a non-member are required to go through the SPP (transmission) Interconnection Review Process as defined in the SPP Criteria document *(SPP Planning Criteria 5.5 Interconnection Review Process, SPP Planning Criteria Appendix PL-6 Interconnection Review Process Details, and SPP Tariff Attachment Z1 – Aggregate Transmission Service Studies Procedures)*.
- Generation interconnections follow the SPP generation interconnection process (for both small and large generators) as defined in the SPP Open Access Transmission Tariff. *(SPP Tariff Attachment V – Generator Interconnection Procedures)*.
- Delivery point interconnections follow the SPP Delivery Point Addition process as defined in the SPP OATT which addresses additions, modifications, or abandonments of delivery point facilities (SPP Tariff Attachment AQ – Delivery Point Addition Process).

Both the SPP OATT and SPP Criteria document are posted on the Open Access Same-Time Information System (OASIS) and SPP's website at www.spp.org.

1.0 General Facility Connection Requirements:

Facility Connection with Regional electric transmission and distribution facilities may be permitted provided such connection complies with the procedures and requirements set forth herein:

1.1 Definitions:

1.1.1 Company: Company shall mean OG&E and by reference include all applicable transmission facilities and all transmission facility owners within the Region. This definition does not imply the taking of transmission service under the Regional Open Access Transmission Tariff.

1.1.2 Owner: Owner shall mean a person or entity responsible for ownership, operation and maintenance of facilities connected with Company.

1.1.3 Facility Connection: Facility Connection shall mean the point where the Company's and Owner's facilities physically meet.

1.1.4 Transmission: Transmission shall mean Company facilities operated at 60 kV and higher.

1.1.5 Generating Source: A Generating Source is defined to exist when ANY of the following conditions are met:

A. Owner's facilities can produce sustained watt or var flow into Company's facilities at the closed Facility Connection.

B. Owner's facilities can energize Company's facilities across the Facility Connection at sustained levels of fifty-one (51) volts or more during times when the Company's source is de-energized.

C. Owner's facilities can energize the Facility Connection with sustained voltage magnitude and frequency quantities that differ from Company's values.

D. Owner's facilities can contribute fault-current to Company's facilities at the Facility Connection.

Note: Sustained shall mean in excess of one (1) second duration.

1.2 All applicable Local, State, and Federal statutes shall govern connection of Owner's facilities with Company's facilities. In addition, Owner's facilities shall be installed in accordance with all provisions set forth in: Company's Facility Connection Requirements; National Electrical Safety Code (ANSIC2); National Electrical Code (NFPA70); or North American Electric Reliability Council (NERC); American National Standards Institute (ANSI); Institute of Electrical and Electronics Engineers (IEEE); or other Regulatory or Governing Body having jurisdiction. Connection of Owner's facilities with Company's facilities shall further be governed by any applicable statute, rule, order, provision, guide, or code of an organization, council, institute, regulatory or governing body having jurisdiction over such matters.

1.3 Owner shall be responsible for all engineering studies, design, modeling data, impact and facilities studies required by RTO, and installation, required for connection with Company's facilities.

1.4 Owner shall be responsible for compliance with all permits, licenses, fee, rules, regulations, standards, agreements, ordinances, inspections, and other requirements imposed by Company or any regulatory or governmental body having jurisdiction. There is no obligation on the part of the Company to connect, or to remain connected whenever Owner's facilities are out of compliance. In addition, Owner shall be responsible for and Company shall require Owner facilities or the Facility Connection between Owner's facilities and Company's facilities to be modified in accordance with all applicable statutes, rules, orders, provisions, guides, or codes of an organization, council, institute, regulatory or governing body having jurisdiction over such matters.

1.5 Because of increased risks and potential hazards inherent with operating Owner's facilities connected with Company's facilities, overall safety for life, quality of service and property is paramount. Company shall disconnect Owner's facilities anytime Owner's facilities pose a dangerous condition, and such disconnection is appropriate to protect safety of Company's employees, customers, general public, or to maintain integrity of the Company's facilities.

1.6 Owner shall provide Company a minimum, of one hundred and eighty (180) days written notice of its intent to connect facilities with the Company's system. Failure to give such notice shall render Owner liable for all damages to Company's property, other customers' property, injury to persons, or any other damages resulting from unauthorized connection. Notice of intent shall include such information as:

1.6.1 Location

1.6.2 Connected kVA

1.6.3 Average and Peak Watt Demand

1.6.4 Reactive Power Requirements

1.6.5 Connected Generation & Type: (synchronous, induction, converter)

1.6.6 Large Motors including Type (synchronous, induction, VFD)

1.6.7 Fault Current Limits

1.6.8 Power Quality Requirements

1.6.9 Reliability Requirements

1.6.10 Voltage Level

1.6.11 Insulation and Insulation Requirements

1.6.12 Other Requirements

Should Company be unable to evaluate Owner's request to connect as submitted, Company shall provide Owner a written explanation of information required to complete the evaluation.

1.7 Only written notice shall constitute acceptance by Company. Written approval by Company does not waive any requirements pertaining to Owner's installation which may be governed directly by other jurisdictional bodies. Company's specifications and requirements are designed towards protecting the safety of life, quality of service and the Company's property, and do not assume nor ensure proper protection of Owner's facilities equipment during electrical faults.

1.8 When Company is required to incur expenses necessary to make extensions or improvements of its lines or additions to its disconnecting devices, transformers, meters, breakers, relays, controls, data systems, or to make any other equipment modifications relating to its circuits, substations, or apparatus necessary to connect Owner's facilities, and such expenses made are attributable to this application, then all costs incurred by Company for Facility Connection shall be borne by Owner as set forth in the connection agreement. Such costs are due and payable prior to Company commencing construction and are non-refundable in whole or in part at any time.

1.9 Owner of generation resources (including dispersed generation) may be required by Company to provide Automatic Voltage Control ("AVR"), including the ability to follow a voltage schedule and/or Primary Frequency Response ("PFR") capabilities. Costs of any required AVR or PFR equipment shall be borne by Owner as set forth in the connection agreement.

1.10 Owner and Company shall execute appropriate agreements for connected service prior to installation of any equipment. Energy supplied to Company, as well as energy used by Owner, shall be compensated in accordance with applicable tariffs, rules, and regulations currently on file with the regulatory body having jurisdiction, or which may be filed and approved by the regulatory body having jurisdiction.

1.12 Company may require Owner's facility design to include an appropriate automatic disconnecting device to be controlled by any or all of the following: overcurrent relays, automatic synchronizing relays, voltage relays, frequency relays, ground fault detection relays, or any other automatic relaying equipment necessary to ensure proper protection and safety of Company employees, customers, equipment, and overall system integrity. The Company reserves the right to review, inspect, and approve Owner's design and shall not give approval to connect until any concerns relating to Owner's design have been remedied.

1.13 Company shall procure, install, and maintain all metering equipment required to measure energy exchanged between Owner and Company across the Facility Connection. Energy shall be measured at delivery voltage.

2.0 Distribution Facility Connection Requirements

2.1 Company's distribution facilities operate at voltage levels of less than 60 kV. These facilities require stringent standards of security, reliability, quality, and controllability of the electrical facility.

2.1.1 Distribution Facilities - General Requirements

A. Owner's facility design shall at a minimum conform to the grounding practices/requirements of the National Electric Code (NEC).

B. Electrical metering shall be provided using devices specified by the Company. Such equipment shall be proven operational before electrical operation begins.

C. Maintenance of Facility Connection should be coordinated with the Company.

D. Supervisory Control and Data Acquisition (SCADA) may be required for Facility Connection.

2.1.2 Distribution Facilities - 2.4 kV through 34.5 kV Requirements

A. Fuses or circuit breakers with protective relays may be required at Facility Connection. Such line-sectionalizing devices may be required to be remotely controllable.

B. Structures at Facility Connection may be required to be of steel construction based on Company construction practices.

C. Sectionalizing devices shall require load breaking and fault interrupting capability.

- In general, the required load breaking capability is 1,200 amps and the fault interrupting current is 16kA (kilo-amps interrupting).
- Under certain circumstances, the Company may require load breaking capability of 3,000 amps and the fault interrupting current of 40kA.

D. Protective relay schemes of Owner shall be coordinated to operate with protective relay schemes of Company facilities.

E. Control power may be required to be from a DC supply.

F. Multiple remote-controllable line-sectionalizing switches or circuit breakers with protective relays may be required of the Owner at the Facility Connection.

3.0 Transmission Facilities Connection Requirements

3.1 Company's electrical facilities include transmission lines operating at voltage levels of 60 kV and higher. Higher voltage levels require stringent standards of security, reliability, quality, and controllability of the electrical facilities.

3.1.1 Transmission Facilities - General Requirements

A. Any electrical structure or equipment utilized for high-voltage service shall be connected to an earth-ground grid that measures no more than 0.6 ohms resistance to earth. Such value shall be measured with equipment and techniques approved by the Company and shall be certified by a measuring contractor qualified for this service. The connectors and components of the grounding grid shall be adequate for the anticipated short-circuit current magnitude and duration.

B. Supervisory remote control and electrical metering shall be provided using devices and communications paths specified by the Company. Such equipment shall be proven operational before electrical operation begins.

C. Maintenance at the Facility Connection shall be coordinated with the Company.

D. Inspection at the Facility shall be coordinated with the Company.

E. If a new substation is to be built along a double circuit line owned by Company to interconnect new generation, both existing circuits must be tied into the new substation at the point of interconnection.

F. If reactive power compensation is determined during the study process to be needed, it is required to be installed on the bus at the appropriate Company facility. It will not be installed in series with any gen-tie lines.

G. All new substations shall be built and designed to allow for future expansion

H. All new interconnections to the OG&E Transmission System (Lines) shall be via a switchable device(s) of which OG&E owns and operates

3.1.2 Transmission Facilities - 60 kV through 138 kV Requirements

A. Multiple remotely controllable line-sectionalizing switches or circuit breakers with protective relays may be required at Facility Connection.

B. Transformers capable of serving load greater than 14.0 MVA shall be controlled by a primary circuit switcher or circuit breaker with appropriate protective relaying.

C. Structures at the Facility Connection may be required to be of steel construction.

D. Sectionalizing devices may require load breaking and/or fault interrupting capability.

E. Protective relay schemes of Owner shall be integrated to operate with protective relay schemes on Company facilities.

F. Protective relaying shall include both primary and backup schemes.

G. Substations with six or greater transmission facility connections shall be ring-bus or breaker-and-a-half configuration.

H. If an option to build standalone network upgrades is exercised by Owner, all construction shall be to Company standards. Also, it will be required for a Quality Assurance Inspector working for Company to be on site at all times during construction of stand alone network upgrades, whose position will be funded by Owner. All Generation interconnections to the OG&E Transmission System (Lines) at 138kV shall be into a new ring bus or breaker and a half substation to be designed constructed owned and operated by OG&E and paid for by interconnecting customer.

I. When the load on an individual substation containing multiple transformer banks exceeds 20MVA, a second source will be required. When the total substation loading of multiple substations exceeds 30MVA on a single transmission line, a second source will be required. Loads in excess of 40MVA must be planned for restoration by automatic or supervisory control. To limit the number of series motorized sectionalizing switches, no more than 160MVA of total capacity may be tapped between circuit breakers.

3.1.3 Transmission Facilities - 161 kV and Higher Requirements

A. All requirements for lower-voltage connection shall apply. In addition, the following requirements shall apply:

B. All interconnections to the OG&E Transmission System (Lines) shall be into a new ring bus or breaker and a half substation to be designed constructed owned and operated by OG&E and paid for by interconnecting customer.

C. Substation design shall be ring-bus or breaker-and-a-half configuration.

D. Control power shall be supplied from redundant DC supply systems.

E. Protective relaying shall include dual primary schemes.

F. In the event that the Point of Interconnection is a new substation on Company's system, the new substation must not be closer than 22-line miles from any existing Company substation. If the desired POI is within a 22-line mile radius of an existing substation, Owner will be required to interconnect into existing facility.

G. All 345kV substations are designed on a case by case basis.

H. All 138kV and above transmission line crossings must be approved by OG&E and all modeling of the crossings provided.

I. If the crossing is a generator lead crossing a critical transmission backbone, the crossing may have to cross underneath at the expense of the entity crossing.

4.0 Generating Source Facility Connection Requirements

4.1 General Requirements

4.1.1 Generating Sources 5,000 kVA and larger shall be three (3) phase to qualify for Facility Connection with Company's facilities.

4.1.2 Generating Source shall not close or reclose automatically onto a de-energized Company Facility Connection.

4.1.3 Disconnecting equipment shall have a visible break between Owner and Company facilities for connections 600 volts and above.

4.1.4 Company shall determine the acceptable minimum aggregate power factor at Facility Connection. Appropriate billings, payments, or adjustments to compensate Company shall be specified in the Facility Connection agreement.

4.1.5 Owner Standby or Emergency Generating Sources will require no special relaying or metering when installation is designed to prevent "hot transfer of Owner's load" going "on" or "off" from the Standby source to the Company's facilities, provided all requirements can be handled with control circuit interlocks.

4.1.6 Supervisory Control and Data Acquisition (SCADA) may be required by Company to connect Generating Source to Provider facilities.

4.1.7 Connection to the Company's facilities shall be at 60 Hz alternating current.

4.1.8 For parallel generation connection, the generator shall be connected using a WYE-DELTA Generator Step Up transformer and shall be connected WYE to Company's facilities .

4.2 Generating Source Types

4.2.1 Synchronous Generating Sources

Synchronous Generating Sources shall utilize three-phase circuit breakers, which meet or exceed the following requirements:

A. Rated for 2.0 per unit voltage across open contacts.

B. Interrupt maximum available fault currents between Owner's Generating Source and Company's facilities.

C. Open for frequency and voltage deviations specified by Company.

D. Utilize synchronism check within +/- 10 degrees and +/- 5 percent of nominal voltage on each side of the breaker prior to closing the breaker between Company's and Owner's facilities.

E. Provide ground fault detection and tripping for breaker anytime an ungrounded circuit configuration exists as the result of opening the Company's source to the Facility Connection.

F. Continuously monitor breaker control power source.

4.2.2 Induction Generating Sources

Induction Generating Sources shall utilize three-phase circuit breakers, which meet or exceed the following requirements:

A. Company shall specify frequency and voltage deviations to Owner for which circuit breaker shall open.

B. Breaker control power source shall be continuously monitored.

4.2.3 Converter Generating Sources

Converter Generating Sources shall meet the following requirement:

A. Converter Generating Sources shall cease operation for frequency and voltage deviations specified by Company.

4.3 Generating Source Facility Connections – 20,000 kVA and Greater

4.3.1 Generating Sources shall be operated and maintained under the direction of the Company.

4.3.2 Generating Sources shall operate with excitation systems in automatic voltage-control mode.

4.3.3 Generating Sources shall maintain reactive power output as required by the Company within the demonstrated reactive capability of the unit.

4.3.4 Generating Sources shall be capable of operation at over-excitation power factor of 0.95 and under-excitation power factor of 0.95 at all rated continuous power output levels as measured at the Facility Connection.

4.3.5 In addition to the protection described in 1.12, Generating Sources shall have reverse power, loss of field, differential generator current, differential transformer current, negative sequence current, and inadvertent energization of the generator protection systems.

4.4 Generating Source(s) Facility Connections – Distribution

4.4.1 Owner shall be responsible for providing, owning, installing and maintaining their electrical System, equipment and process designed to operate and conform with all applicable standards and codes including, but not limited to IEEE Standards 519-1992 and IEEE 141-1993 (borderline Visibility curve) and any successor IEEE Standards.

In addition, OG&E policy requires adherence to the latest revision of the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547, Standard for Interconnecting Distributive Resources with Electric Power Systems, IEEE Std. 1547.2, the accompanying application guide and any successor IEEE Standards., and the Oklahoma Administrative Code, Title 165. Corporation Commission Chapter 35: Electric Utility Rates and Chapter 40: Standard Terms of Purchases from Purchasers of 100 KW or Less (where applicable).

4.4.2 Any interconnection of Distributed Generation Resources shall be planned, studied, and approved in accordance with the "OG&E Distributed Resources Interconnection Guidelines."

4.5 Transitional Switching of Generating Sources

4.5.1 Owner may be permitted to utilize approved methods of transitional switching for the purpose of making a synchronized transfer of Owner's load between Owner's Generating Source and Company's facilities. Such transitional switching shall require automatic synchronizing equipment and high-speed switching devices specifically designed to synchronize Owner's Generating Source to the Company for the sole purpose of "hot" transferring the Owner's load "On" or "Off" the Company's facilities.

4.5.2 All Owner requests for transitional switching shall be approved by Company and accomplished in such a manner as not to exceed one (1) second as the maximum time Owner's Generating Source operates connected with Company's facilities.

4.5.3 Owner shall be responsible for all costs associated with transitional switching.

4.6 Inverter-Based Resources (IBR)

4.6.1 Momentary Cessation – IBRs should be designed and configured to continue current injection inside the "No Trip Zone" of the frequency and voltage ride-through curves of the currently effective version of PRC-024 unless a reliability study identifies a system need to cease injecting current. IBRs should be designed and configured to use momentary cessation only outside the "No Trip Zone" if this helps mitigate potential tripping conditions based on interconnection studies.

4.6.2 Phase Jump Immunity – the Company may perform systems studies to identify possible worst-case phase jumps at the point of interconnection (POI) of the interconnecting resources. The company may consider identifying worst case balanced phase jump limits or state that inverter-based resources should not trip for studied credible contingency events (similar to fault ride through (FRT)).

4.6.3 Capability Curve – the Company shall require that IBR owners provide a "composite capability curve" that includes that overall active and reactive capability of the resource as measured at the Point of Measurement (POM). This includes a complete P-Q graph (or table of data representing these data points) at nominal voltage. The reactive capability within that curve should be "dynamic" per FERC Order No. 827. The Company may also require that the capability curve of each type of individual inverter be provided, since this helps verify aggregate capability in the planning models (along with the overall capability curve provided). The capability curve of a BESS (Battery Energy Storage System) extends into both the charging and discharging regions to create a four-quadrant capability curve. The shape of many individual BESS inverter capability curves is almost symmetrical for charging and discharging. From an overall plant-level perspective, the capability curves may be asymmetrical. System-specific requirements may not necessitate the use of the full equipment capability; however, the resources should not be artificially limited from providing its full capability (particularly reactive capability) to support reliable operation of the BPS. The overall composite capability curve of a hybrid plant is the aggregation of the individual capability curves of the generating resources and BESS plus any other reactive devices and less any losses within the facility as measured at the plant POI. The capability curve extends into the BESS charging region to create a four-quadrant capability curve. The curve is not symmetrical for injection and withdrawal. On the injection side, the capability curve will be equal to the sum of capability curves of a generator and capability curve of BESS during discharging. On the withdrawal side, capability will be equal to BESS capability curve, when charging. Note that interconnection requirements may not allow the full use of hybrid resource capability depending on how the BESS can charge and discharge with the generating component and with the grid.

4.6.4 Active Power Frequency Controls – the Company shall ensure that the performance from IBRs aligns with FERC Order No. 842. BPS reliability needs based on specific system characteristics and studies may drive the need for additional requirements for newly interconnecting resources. The Company should specify dynamic active power-frequency response performance of IBRs to ensure consistent and expected performance across the BPS generating fleet. Active power-frequency controls can be extended to the charging area of operation for BESS. The conventional droop characteristic can be used in both discharging and charging modes. Furthermore, a droop gain[33] and deadband should be used in both operating modes, and there should be a seamless transition between modes (i.e., there should not be a deadband in the power control loop for this transition) unless interconnection requirements or market rules preclude such operation. As with all resources, speed of response of active power-frequency control to support the BPS should be coordinated with system needs. The fast response of BESS to frequency deviations can provide reliability benefits. Consistent with FERC Order 842, there should be no requirement for BESS resources to provide frequency response if the state of charge (SOC) is very low or very high (which may be specified by the BA), though that service can be procured by the BA. The conventional droop characteristic can be used in both generating and charging modes of the hybrid. Active power-frequency control capability may be limited by total active power injection and/or the withdrawal limit of the hybrid plant at POI that may be set lower than the sum of active power ratings of the individual resources within the hybrid plant. Due to the presence of the BESS, a hybrid plant can also have the capability of providing frequency response for under frequency conditions, subject to the SOC and set point limits outlined in FERC Order 842.

4.6.5 Fast Frequency Response (FFR) – the company should identify systems needs for FFR, and the company should ensure the capability is available for grids where FFR may be needed. Requirements should be clear in stating whether nonsustained forms of FFR are acceptable and any additional requirements pertaining to the timing aspects of FFR. These issues are not specific to inverter-based resources, yet the company in coordination with the TP and PC should ensure sufficient frequency response capability to arrest large frequency deviations for credible contingency events. BESS are well-positioned to provide FFR to systems with a high rate-of-change-of- frequency (ROCOF) due to not having any rotational components (similar to a solar PV facility). The need for FFR is based on each specific Interconnection's need.35 Sustained forms of FFR help arrest fast frequency excursions and overall frequency control. BESS are likely to be able to provide sustained FFR within their SOC constraints. With the ability for BESS to rapidly change MW output across their full charge and discharge ranges (within SOC limits), BPS voltage fluctuations should be closely monitored, especially on systems with lower short-circuit ratios. FFR capability will depend on the resources making up the hybrid plant. BESS are well-positioned for providing FFR to systems with high rate-of-change-of-frequency (ROCOF) due to not having any rotational components (similar to a solar PV facility). However, if BESS is combined with wind generation facility coordination between resources within, the hybrid may be needed to achieve sustained FFR. Additionally, hybrid plant FFR capability may be limited to total active power injection and/or withdrawal limit of the hybrid plant. The need for FFR is based on each specific Interconnection's need.[56] Sustained forms of FFR help arrest fast frequency excursions but also help overall frequency control. BESS are likely to be able to provide sustained FFR within their SOC constraints. Consistent with FERC Order 842, there should be no requirement for hybrid resources to reserve headroom or violate set point or SOC limits to provide frequency response though the BA can procure that service.

4.6.6 Reactive Power-Voltage Control – the company should ensure that the performance from newly interconnecting generating resources aligns with FERC Order No. 827. The company may have additional requirements as needed for BPS reliability needs based on specific systems characteristics. The company should clearly differentiate between large and small disturbance behavior for voltage response. For small disturbance behavior, where voltage remains within the continuous operating range of the inverters and plant controller, the company should have clear specifications for the time in which that voltage support should be provided. BESS should be configured to provide dynamic voltage control during both discharging and charging operations to support BPS voltages during normal and abnormal conditions. TOPs should provide a voltage schedule (i.e., a voltage set point and tolerance) to all BESS, applicable to both operating modes. The dynamic voltage support capability of a hybrid is a combination of capability of the generating resource(s) and BESS, which are part of the hybrid. The BESS portion of the hybrid has the capability to provide dynamic voltage control during both discharging and charging operations. Note that system specific requirements may not necessitate the use of the full equipment capability of the hybrid plant. TOPs should provide a voltage schedule (i.e., a voltage set point and tolerance) to the hybrid that can apply to both operating modes (injection and withdrawal).

4.6.7 Reactive Current-Voltage Control – the company should ensure that the large disturbance behavior from IBRs provides dynamic voltage support through their reactive current-voltage controls, when voltage falls outside the continuous operating range of the inverters (and local inverter controls take over). This includes both the magnitude and timing of reactive current injection, and the prioritization between reactive and active current. BESS should be configured to provide dynamic voltage support during large disturbances both while charging and discharging. BESS portion of the hybrid can be configured to provide dynamic voltage support during large disturbances both while charging and discharging.

4.6.8 Reactive Power at No Active Power Output – the Company may require IBRs to exchange reactive power with the BPS (to provide voltage control) when no active power is generated.

4.6.9 Inverter Current Injection during Fault Conditions – the company shall clearly articulate expected inverter behavior during and immediately following fault events in coordination with the small disturbance active and reactive current controls. This includes the magnitude of the current, the phase relationship of current with respect to voltage, and the time of current injections. The company may consider, based on detailed system studies (likely electromagnetic transient (EMT) studies), establishing fault current requirements for newly interconnecting IBRs since this response is dominated by the controls programmed into the inverter. As the penetration of IBRs continues to grow, pockets of the BPS may require unconventional relaying techniques to ensure secure protection schemes. The IEEE P2800 effort should consider standardizing fault current injection for inverter-based resources after further deliberation by inverter manufacturers, relay manufacturers, and protection and stability engineers. BESS should be configured to provide fault current contribution during large disturbance events that can support legacy BPS protection and stability. Inverter limits will need to be met, as with all inverter-based resources; however, SOC may not be an issue for providing fault current for BESS since faults are typically cleared in fractions of a second. Additionally, limits on dc voltage magnitude can apply.

4.6.10 Return to Service Following Tripping – the company in coordination with their BA, should specify the expected performance of IBRs following a tripping event. This may include automatic reconnection after a predefined period of time or may include manual reconnection by the BA. Ramp rates during return to service conditions should be specified as well. Following “system black” conditions, IBRs should not attempt to automatically reconnect to the grid (unless direct by the BA) so as to not interfere with blackstart procedures. BESS should return to service following any tripping or other off-line operation by operating at the origin (no significant exchange of active or reactive power with the BPS) and then ramp back to the expected power output. This is a function of plant settings and interconnection requirements set by the BA or TO. Hybrid plant should return to service following any tripping or other off-line operation by operating at the origin (no significant exchange of active or reactive power with the BPS), and then ramp back to the expected set point values, as applicable. This is a function of settings and any requirements set forth by the BA (or TO in their interconnection requirements).

4.6.11 Balancing – the company, in coordination with their BAs, should require the capability to limit active power ramp rates (in both directions) to mitigate any significantly large power swings over a short period of time, depending on weather when applicable. This is a balancing ramp rate typically expressed in terms of percentage output change per minute. IBRs should be required to received automatic generation control (AGC) dispatch signals if the market/agreement structure indicates this. The capability to provide balancing services for the BPS should be available from all BESS. BAs, TPs, PCs, and RCs should ensure requirements are in place for appropriate balancing of the BPS.

4.6.12 Monitoring – the company should specify data recording and real-time monitoring requirements for IBRs (and all generating resources) to effectively monitor resource performance and provide information necessary to perform event analysis. This should include capturing high resolution data available at the POI, some inverter-level high speed data, and sequence of events recording.

4.6.13 Operation in Low Short-Circuit Strength Systems – the company should endure they understand and have studied areas of their systems where potential low short-circuit strength conditions could occur. The company should have sufficient requirements in place to reliably study and integrate inverter-based resources to the BPS, including these areas. In situations where potential low short-circuit strength conditions could occur, the company should ensure they have sufficient data and information needed to perform studies in these areas. This includes coordination with the GO, particularly during the interconnection studies process, to obtain EMT models or provide the GO with sufficient information to prove reliable controls and capability to operate in these types of conditions. BESS should utilize grid forming operation, as appropriate (see below), to support BPS stability and reliability in low short-circuit strength operating conditions.

4.6.14 Fault Ride-Through Capability – The company should consider the reliability need for establishing FRT requirements for interconnecting generating resources and other grid-supportive devices. These requirements apply both synchronous and nonsynchronouse generating resources. This requirement may include qualitative and quantitative requirements described below:

> **Qualitative:** Generation resources may be required to have FRT capability for all expected (studied) credible contingency events unless the plant is consequentially isolated due to the fault, the plant is part of a remedial action scheme, or the plant is allowed to trip by exception from the TP based on system studies. These requirements are applied during the FAC-002 interconnection studies process.
>
> **Quantitative:** These requirements typically involved a performance envelope (FRT capability) that must be met by the resource, typically derived based on interconnection studies, grid codes, Reliability Standards, and other factors deemed necessary by the company. Having these requirements ensures that the resource, particularly IBRs, are unlikely to operate in a mode of operations that has not been previously studied. These types of requirements also ensure inverter manufacturers are designing equipment robust enough to withstand BPS transient events.

BESS should have the same capability to ride through fault events on the BPS when point of measurement (POM) voltage and frequency is within the curves specified in the latest effective version of PRC-024. This applies to both charging and discharging modes; unexpected tripping of generation or load resources on the BPS will degrade system stability and adversely impact BPS reliability. Ride-through capability is a fundamental need for all BPS-connected resources such that planning studies can identify any expected risks. However, the behavior during ride-through while discharging and charging may be different. A hybrid plant should have the same capability to ride through fault events on the BPS, when point of measurement (POM) voltage is within the curves specified in the latest effective version of PRC-024, subject to limitations of legacy equipment. For the BESS part of the hybrid, this applies to both charging and discharging modes.

Unexpected tripping of generation or load resources on the BPS will degrade system stability and adversely impact BPS reliability. Ride-through capability is a fundamental need for all BPS-connected resources such that planning studies can identify any expected risks.

4.6.15 Grid Forming – the company should thoroughly understand when and where grid forming inverter capability may be needed on the BPS prior to specifying its used in any interconnection requirements. Its use may include systems with a high penetration of IBRs (localized or widespread) or systems that may be utilizing IBRs for blackstart purposes. Industry is still developing the technology and its recommended use in conjunction with other solution options. If the inverters employ grid forming technology, this information should be provided to the company. BESS have the unique capabilities to effectively deploy grid forming technology to help improve BPS reliability in the future of high penetration of inverter-based resources. Key aspects that enable this functionality include availability of an energy buffer to be deployed for imbalances in generation and load, low communication latency between different layers of controllers, and robust dc voltage that enables synthesis of an ac voltage for a wide variety of system conditions. In grids where system strength and other stability issues are of concern, BESS may be required to have this capability to support reliable operation of the BPS. TPs and PCs should develop interconnection requirements and new practices, as needed, to integrate the concepts of grid forming technology into the planning processes. The BESS portion of a hybrid plant has the unique capabilities to effectively deploy grid forming technology to help improve BPS reliability in the future of a high penetration of inverter-based resources. Newly interconnecting hybrid plants should consider using grid-forming technology to support the BPS under these future conditions.

4.6.16 System Restoration and Blackstart Capability – System restoration and black start capability considerations are part of NERC EOP-005-3 and EOP-006-3. While not specifically part of the interconnection requirements, two considerations worth highlighting include the following:

> During system restoration, the TOP and BA typically require coordination and instruction prior to a GO returning to service. This should be explicitly stated such that inverter-based resources do not unexpectedly automatically reconnect during the system restoration process.
>
> Inverter-based resources are not required to have blackstart capability: however, if they do, that information should be provided to the TOP and TO as part of the interconnection process.

BESS may have the ability to form and sustain their own electrical island if they are to be designated as part of a blackstart cranking path. This may require new control topologies or modifications to settings that enable this functionality. Blackstart conditions may cause large power and voltage swings that must be reliably controlled and withstood by all blackstart resources (i.e., operation under low short circuit grid conditions). For BESS to operate as a blackstart resource, assurance of energy availability as well as designed energy rating that ensures energy availability for the entire period of restoration activities is required. At this time, it is unlikely that most legacy BESS can support system restoration activities as a stand-alone resource; however, they may be used to enable start-up of subsequent solar PV, wind, or synchronous machine plants. Hybrid plants may have the ability to form and sustain their own electrical island if they are a part of a blackstart cranking path. This may require new controls topologies or modifications to settings that enable this functionality. Blackstart conditions may cause large power and voltage swings that must be reliably controlled and withstood by all blackstart resources (i.e., operation under low short circuit grid conditions). For the hybrid to operate as a blackstart resource, assurance of energy availability is needed as well as a designed energy rating that ensures energy availability for the entire period of restoration activities. At this time, it is unlikely that most legacy hybrid plants can support system restoration activities as a stand-alone resource; however, they may be used to enable start-up of subsequent solar PV, wind, or synchronous machine plants and accommodate fluctuations in supply and demand.

4.6.17 Protection Settings – the company should review the key findings and recommendations from the disturbance reports involving solar PV resource Tripping, and may consider incorporating these findings into interconnection requirements, as applicable. This may include:

Clarification that PRC-024 sets the minimum performance requirements, and inverter protection should be set at the limits of equipment safety and reliability.

Tripping on calculated frequency should be based on an accurately calculated and filtered measurement over a time window and should not use an instantaneously calculated value.

Inverter overvoltage protection should be set as high as possible within equipment limitations. The PRC-024 curve uses a filtered RMS voltage measurement and should not be applied for transient, sub-cycle overvoltages.

The company should specify expected performance during successive fault events within a predefined period of time.

Any dc reverse current protection and phase lock loop (PLL) loss of synchronism should not result in inverter tripping, in most cases, for BPS fault events within the “No Trip Zone” of the currently effective version of PRC-024. Tripping within the PRC-024 “No Trip Zone” should be allowed for inverter faults that can lead to failure.

Inverter rate-of-change-of-frequency (ROCOF) protection should be disabled unless an equipment limitation exists that requires that inverter to trip on high ROCOF. In most instance, ROCOF protection should not be used for BPS-connected resources.

4.6.18 Power Quality – the company should specify recognized outage scenarios for IBR to assess power quality impacts. IBRs may request the company to provide grid harmonic impedance characteristics (from TO reliability studies), in particular reactive facility data, in order to manage potential resonance issues. The company may measure background power quality indices prior to IBR interconnections for design reference and later power quality responsibility separation. Permanent power quality monitoring is recommended for commercial operations. As needed, the company should characterize actual harmonic distortion performance during the trial operation (during plant commissioning) period prior to the commercial operation date. Any harmonic distortion issues should be addressed based on the requirements established by the company. The company should require that the GO provide advanced notice prior to implementing firmware updates to the facility as firmware updates can improve or degrade power quality performance.

4.6.19 State of Charge (NEW) - The SOC of a BESS affects the ability of the BESS to provide energy or other ERSs to the BPS at any given time. In many cases, the BESS may have SOC limits that are tighter than 0–100% for battery lifespan and other equipment and performance considerations. SOC limits affect the ability of the BESS to operate as expected, and any SOC limits will override any other ability of the BESS to provide ERSs or energy to the BPS. These limits and how they affect BESS operation should be defined by the equipment manufacturers and plant developer, agreed upon by the GO, and provided to the BA, TOP, RC, TP, and PC.

Similarly to the standalone BESS, the SOC of a BESS portion of the hybrid may affect the ability of the hybrid to provide energy or other ERSs to the BPS at any given time.[58] These limits and how they affect BESS operation should be defined by the hybrid owner and provided to the BA, TOP, RC, TP and PC.

BESS SOC will be optimized by the hybrid plant controller in coordination with other parts of the hybrid (wind or solar) based on irradiance and/or wind conditions, market prices, energy, and ESR obligations of the hybrid. In addition, the manner in which the BESS would charge is to be communicated by the GO. Here, system loading conditions and generation from other parts of the hybrid plant will play a role. For example, in a wind-BESS hybrid plant during low load high renewable scenarios, the BESS may be charged directly from the wind output. In this scenario, the hybrid plant will not appear as a load on the system. Alternatively, the plant may be directed to charge from the network in order to increase the loading on the system to satisfy stability considerations.

4.6.20 Oscillation Damping Support - BESS can have the capability of providing damping support similarly to synchronous generators and HVDC/FACTS facilities. BPS-connected inverter-based resources could also provide damping support. A major difference from other BPS-connected inverter- based resources is that BESS can operate in the charging mode in addition to the discharging mode, which provide greater capabilities of damping support. BESS can have the capability of providing oscillation damping support, similar to synchronous generators, HVDC/FACTS facilities, and other BPS-connected inverter-based resources. BESS can operate in the both charging and discharging mode, which provides greater capabilities for damping support.

4.6.21 Operational Limits (new)- Based on economics or design considerations, the BESS portion of the hybrid may be operated to only charge from other wind and/or solar part of the hybrid or to charge from the grid as well. The hybrid owner should provide this information to the BA, TOP, RC, TP and PC. Hybrid plant owners may choose to limit injection/withdrawal at the POI to a level that is lower than actual capability of the hybrid. The hybrid owner should provide this information to the BA, TOP, RC, TP and PC. Where such limit exists, the studies as well as voltage support and frequency support requirements may apply only up to the limits.

5.0 Commissioning of the Facility Connection

5.1 Company may measure and document the harmonics present at the Facility Connection before and after such connection is made.

5.2 Company reserves the right, but does not assume the duty, to inspect, test, or check Owner’s equipment in any way deemed appropriate to confirm operation and verify system protection characteristics. Company does not assume any responsibility in connection with such Owner’s equipment or the inspection thereof.

5.3 Metering equipment shall be verified by Company or its designated agent.

6.0 Operating Requirements:

6.1 Owner agrees to respond to Company requests during abnormal conditions.

6.2 Owner shall ensure competent personnel are available to operate, maintain, and repair connected generating equipment at all times when such equipment operates in parallel with Company’s facilities.

6.3 Company may require connected generating sources to have both normal and emergency paths for supervisory control, metering, or voice communications systems.

6.4 The Company requires coordination with the Company's automatic underfrequency load shedding. Wholesale service providers shall be required to provide the Company with a documented manual load shed plan.

6.5 Owner shall provide all available operating data upon request.

7.0 Modeling Requirements:

7.1 Timing and quality of Modeling Data Submittals during Interconnection Process - The modeling data submitted during the feasibility study and into the system impact study should be the most accurate and reasonable modeling information available to the GO at the time. This data should be screened for basic correctness as prescribed by the TP and PC. Once the interconnection studies are approved, the data should become final. Any changes to the data should become subject to material modification determinations. Changes to control system settings, increases in output, facility topology changes, and any other change that modifies the electrical characteristics or response of the plant should trigger the need for a material modification determination. During the commissioning process, GOs should submit the desired control system settings to the TOs to review and comment prior to implementing them. The submission should include a side-by-side comparison with the modeling data. This gives the TOs an opportunity to capture performance deficiency while the commissioning team is still onsite. TOs should be enforcing requirements for GOs to submit the finalized as- built modeling data after the plant has been commissioned and is in-service within a prescribed time frame (e.g., 120 days after in-service date). This final step ensures modeling data matches as-built specification sheets, oneline diagrams, and inverter and plant-level control settings. The material modification determinations should apply during the entire time of in-service operation and is not only applicable to the interconnection process. TOs should have clear specifications for what constitutes a "material modification" per NERC FAC-001-3.

7.2 Steady- State Modeling - the company should have clearly documented requirements for steady-state modeling that ensures that sufficient data is gathered to model these resources in local and interconnection-wide powerflow base cases. In most cases, dispersed power-producing resources (i.e., wind and solar PV) should be represented in the powerflow base case using an equivalent representation clearly specified by the company in their requirements.32 A single-line diagram showing impedances and equipment ratings should be provided to the company with the accompanying model. The company should also ensure that all necessary control settings and ratings used for modeling purposes are collected during this process to ensure accurate controls configuration in the base case.

7.3 Positive Sequence Dynamics Modeling – the company shall have different requirements based on their local modeling and studies practices, which may differ from any interconnection-wide case creation requirements. The company may only allow standard "generic"33 simulation library models with accurate parameters to reflect each specific facility, may require detailed user-defined models, or may require both a detailed user-defined model and a generic model in some cases. Detailed models are often used for local interconnection reliability studies (localized studies as well as interconnection study process studies) while generic models are typically used in the interconnection-wide base cases per MOD-032-1. In any case, the company should be clear in the types of models that are expected to be provided for the interconnection process. The latest library models used for dynamic simulations should be required; these are updated occasionally by industry stakeholder groups. The company should refer to the NERC list of acceptable models for more guidance on interconnection-wide modeling.

7.4 Short-Circuit Modeling – the company should have clear requirements regarding how to model inverter-based resources and all generating resources for short-circuit studies. The necessary elements for these short- circuit models should be specified in the requirements including relevant transmission circuits, transformers, collector systems, diagrams and equipment ratings, inverter-level data, and other data for the purposes of modeling. Short-circuit modeling practices are evolving; however, necessary data should be collected to have the information needed for the company to improve these models as they evolve in coordination with the GO. The current recommendation from IEEE Power System Relaying and Control Committee C24 Working Group is to provide a table of positive and negative sequence current injection for different positive sequence voltage levels for different fault types.

7.5 Electromagnetic Transient Modeling - the company should clearly articulate the level of EMT modeling necessary as part of their interconnection requirements or modeling requirements documentation. EMT simulations may be needed in certain situations or scenarios involving inverter-based resources. These include, but are not limited to, subsynchronous control interactions near series compensation or interaction with other neighboring inverter-based resources, low short-circuit strength pockets, or other sub-synchronous or super-synchronous controls issues. The company should specify requirements for inverter-based resources to provide EMT models in situations where an EMT-type study may be needed now or in the foreseeable future. Obtaining EMT models after the fact becomes challenging, so obtaining the models during the interconnection process and requiring model updates as changes are made within the facility are important aspects of maintaining accurate system models

7.6 Benchmarking Positive Sequence and EMT Models - the company should ensure verification that the positive sequence dynamic model reflects the behavior of the overall inverter-based resource. This is particularly critical for the large disturbance behavior of the resource that may not be captured as part of the currently effective MOD-026 and MOD-027 testing and verification requirements. Interconnection requirements should clarify and detail the necessary steps to provide the required level of verification. This may include benchmarking simulations or testing by the inverter manufacturer to ensure that the positive sequence model matches the EMT model. The EMT model should be based on the real code implemented in the inverters installed in the field. It is important for the company to ensure that the models reflect the most accurate possible assumptions during the interconnection study process and that the dynamic models (both EMT and positive sequence RMS models) reflect the as-built settings upon commissioning

7.7 Models Matching As-Built Controls, Settings, and Performance – All BESS and hybrid plant GOs (in coordination with the developer and equipment manufacturers) should endure that the models used to represent BESS and hybrid power plants accurately represent the controls, setting, and performance of the equipment installed in the field. This requires concerted focus by the GO, developer, and equipment manufacturer during the study and commissioning process as well as the more rigorous verification and testing by the TP and PC throughout. GOs should also provide updated models to the TP and PC that reflect as-built setting and controls after plant commissioning. The TP and PC should study any modifications to equipment settings that have an impact on the electrical performance of the equipment prior to changes being made, per the latest effective version of NERC FAC- 002.
TPs and PCs should ensure their modeling requirements and processes clearly define the types of models that are acceptable, the level of detail expected for each model, and the benchmarking between models required during the planning study process. GOs, GOPs, and developers of each BESS and hybrid power plant should verify, in coordination with their TP, PC, and equipment manufacturer, that the dynamic models fully represent the expected behavior of the as-built facility.

7.8 Software Enhancements - Simulation software vendors should work with BESS and hybrid plant inverter and plant-level controller manufacturers to develop more flexible dynamic models to represent these facilities. Software developers should be proactive in addressing modeling challenges faced by TPs and PCs in this area, particularly as the number of these types of resources rapidly increases in interconnection-wide base cases. Software vendors should support the advancement of using "real-code"[7] models or other user-defined models in a manner that does not degrade or limit the quality and fidelity of the overall interconnection-wide base case. Software vendors should consider adding model validation, verification, quality review, and other screening tools to their programs to support TP and PC review of model quality. Software vendors should improve the steady-state model representation of hybrid plants such that engineers are not required to use workarounds, such as modeling two separate units to represent a single hybrid plant.

Attachment A

Facility Connection Specifications

1. VOLTAGE LEVEL AND MW/MVAR CAPACITY

1.1 OG&E Transmission System Voltages - Nominal transmission system voltages presently on the OG&E transmission are 500kV, 345kV, 161kV, 138kV, and 69kV.

1.2 Interconnection Supply Voltage – the interconnecting facility supplied from the transmission system under system normal voltage will range between .95 and 1.05 per unit and under single transmission element outage conditions voltage will range between .90 and 1.05 per unit of nominal.

1.3 Interconnection Capacity for Load – the load connected to the transmission system cannot exceed the MW and MVAR capacity or demand levels requested and studied in the System Impact Study. If these levels need to be exceeded, another System Impact Study and Facilities Study may need to be performed.

1.4 Interconnection Capacity for Generators -- The interconnecting generator facility cannot exceed the MVA level studied in the System Impact Study. If the interconnecting generator wishes to exceed the studied MVA level, another System Impact Study, and if required a Facility Study may need to be performed. The generator owner will pay for all costs, including the studies and any resulting new facilities.

2. BREAKER DUTY AND SURGE PROTECTION

2.1 Circuit breaker minimum duty and design shall conform to OG&E Specifications for 69-161kV Power Circuit Breakers, OG&E Specifications for 345kV Circuit Breakers, 2.1.4 ANSI/IEEE C37.010-1999, and ANSI/IEEE C37.04-1999 and any successor ANSI/IEEE Standards. Depending on the interconnecting facilities and the location of the interconnection, higher interrupting and/or continuous current ratings may be required.

2.2 Lightning Arresters shall be installed on the high and low side of all transformers. If there are no transformers at the station, then each line terminal shall have arresters installed. The arresters shall be station class metal oxide varistor (MOV) type with a maximum continuous phase to ground (MCOV) rating of:

2.2.1 48 kV to 69 kV for 69 kV systems

2.2.2 88 kV to 108 kV for 138 kV systems

2.2.3 106 kV to 132 kV for 161 kV systems

2.2.4 209 kV to 245kV for 345 kV systems

2.2.5 396 kV for 500 kV systems

2.2.6 These ratings may be adjusted by OG&E based on the Temporary Overvoltage Capability (TOC) of the proposed arrester to be used. The manufacturer's TOC data for each arrester shall be supplied to OG&E by the interconnecting party.

3. SYSTEM PROTECTION AND COORDINATION

3.1 The interconnecting party shall provide protective relaying systems consistent with the guidelines listed below. Proposed protective relaying requirements for each interconnection will be subject to review and approval by OG&E for proper coordination after receipt of a preliminary single-line drawing of the proposed interconnection and a single-line drawing and drawings of the party's interconnected system.

3.2 Interconnecting parties shall make every effort to ensure proper and adequate coordination of protection systems with OG&E consistent with NERC Reliability Standard PRC-001, PRC-024, PRC-027, and any successor NERC Standards.

3.3 The interconnecting party shall provide recloser and fuse ratings, relaying data, relay bill of materials, and line and transformer impedances in coordination with OG&E.

3.4 High-speed pilot primary relaying, high-speed non-pilot secondary relaying and breaker failure relaying are required for 138 kV and higher interconnections. Specialized relaying, such as direct transfer trip, may be required to provide automatic load or generation shedding, or interconnected system separation.

3.5 High-speed pilot primary relaying, high-speed pilot secondary relaying, high speed dual-channel transfer trip and breaker failure relaying may be required at certain interconnections. The primary and secondary pilot channels and direct transfer trip channels shall be on separate systems such as power line carrier and fiber optics. Specialized relaying, such as direct transfer trip, may be required to provide automatic load or generation shedding, or interconnected system separation.

3.6 Transformer protection may include the following: differential relay, sudden pressure relay, pressure relief devices, high side overcurrent backup, neutral overcurrent, and a low oil level lockout. High side protection shall be a fuse, circuit breaker or fault interrupting switch (FIS), with adequate interrupting capability.

3.7 OG&E will not be responsible for protection of the interconnected party's facilities. The party is solely responsible for protecting their equipment in such a manner that faults, unbalances, or other disturbances on the OG&E or the surrounding transmission systems do not cause damage to the party's facilities. Sync check and synchronizing of interconnected facilities is the responsibility of the interconnected facility owner.

4. METERING AND TELECOMMUNICATIONS

4.1 General – Unless otherwise agreed by the parties, OG&E shall design, purchase and install the metering equipment to the operation of the interconnecting facilities and shall own, operate, test and maintain such equipment. Power flows to and from the interconnecting facility shall be measured in analog and/or digital form as required by OG&E. The interconnecting party shall bear all reasonable documented costs associated with the design, purchase, installation, operation, testing and maintenance of the metering equipment. If interconnecting party provided the metering equipment it shall be of the type and configuration specified by OG&E.

4.2 Check Meters - the interconnecting party, at its option and expense, may install and operate, on its premise, one or more check meters to check OG&E's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows. The check meters shall be subject at all reasonable times to inspection and examination by OG&E or its designee. The installation, operation and maintenance thereof shall be performed entirely by interconnecting party in accordance with Good Utility Practice.

4.3 Standards - OG&E shall install, calibrate, and test revenue quality metering equipment in accordance with applicable ANSI standards. Metering for participants in the SPP Integrated Market must also comply with Appendix C – Meter Technical Protocols of the Market Protocols – SPP Integrated Marketplace.

4.4 Testing of the Metering Equipment - OG&E shall inspect and test all metering equipment upon installation and at least once every two (2) years thereafter. If requested to do so by the interconnecting party, OG&E, at the interconnecting party's expense, inspect or test the metering equipment more frequently than every two (2) years. OG&E shall give reasonable notice of the time when any inspection or test shall take place, and the interconnecting party may have representatives present at the test or inspection. If at any time the metering equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at the interconnecting party's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to OG&E's failure to maintain, then OG&E shall pay. If the metering equipment fails to register, or if the measurement made by the metering equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, OG&E shall adjust the measurements by correcting all measurements for the period during which the metering equipment was in error by using the interconnecting party's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the metering equipment as agreed to by the parties, but in no event shall the period be greater than one-half the time from the date of the last previous test of the metering equipment.

4.5 Metering Data - At the interconnecting party's expense, the metered data shall be telemetered to one or more locations designated by OG&E and one or more locations designated by the interconnecting party.

4.6 Voice Communications – the interconnecting party shall maintain satisfactory operating communications with OG&E's transmission system dispatcher or other designated representative. The interconnecting party shall provide standard voice line, dedicated voice line (generator interconnections only) and facsimile communications at its control room or central facility through use of either the public telephone system or a separate voice communications system.

4.7 Data communications - The interconnecting party shall also provide the dedicated data circuit(s) necessary to provide interconnecting facility data to OG&E as required for reliable transmission system operation. Any required maintenance of such data circuit(s) shall be the responsibility of the interconnecting party. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data. All data communication cable, fiber optic or copper, shall conform to OG&E material and installation specifications.

4.8 Remote Terminal Unit – Prior to the operation of the interconnecting facilities a Remote Terminal Unit shall be installed by OG&E at the interconnecting party's expense, to gather accumulated and instantaneous data to be telemetered to OG&E's Transmission Control Center. The communication protocol for the data circuit(s) shall be specified by OG&E. Instantaneous bi-directional analog real power and reactive power flow information shall be telemetered directly to the location(s) specified by OG&E. Each party will promptly advise the other party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other party. The party owning such equipment shall correct such error or malfunction as soon as reasonably feasible. The data for telemetry shall be as dictated by OG&E and be provided to the RTU.

5. GROUNDING AND SAFTEY ISSUES

5.1 When making an interconnection to OG&E's transmission system, the requesting party shall comply with applicable safety laws and building and construction codes, including provisions of applicable Federal, State, or local safety, health, or industrial regulations or codes, and the OG&E Safety Manual and programs.

5.2 OG&E will make final determination as to whether the OG&E facilities are properly protected before an interconnection is energized. The interconnecting facility owner is responsible for proper protection of their own equipment and for correcting such problems before the facilities are energized or interconnected operation begins. OG&E may determine the measures to maintain the safe and reliable operation of the OG&E transmission system.

6. INSULATION AND INSULATION COORDINATION

6.1 Power system equipment is designed to withstand voltage stresses associated with expected operation. Adding or connecting new facilities can change equipment duty, and may require that equipment be replaced or switchgear, telecommunications, shielding, grounding and/or surge protection be added to control voltage stress to acceptable levels. Interconnection studies include the evaluation of the impact on equipment insulation coordination. OG&E may identify additional requirements to maintain an acceptable level of transmission system reliability, equipment insulation margins, and safety. Voltage stresses, such as lightning or switching surges, and temporary overvoltages may affect equipment duty.

6.2 Basic Impulse Insulation Level (BIIL) for OG&E facilities and connections should conform to the following table.

Voltage	Suspended Insulator	Dead-End Insulator
69 kV	350 kV	350 kV
138 kV	650 kV	748 kV
161 kV	650 kV	748 kV
345 kV	1,300 kV	2,070 kV
500 kV	1,800 kV	2,070 kV

7. VOLTAGE, REACTIVE POWER, AND POWER FACTOR CONTROL

7.1 Voltage Schedule for Generation – The OG&E Transmission Control Center will provide seasonal voltage schedule targets for all generation connected to the Company transmission system. Only generation that meets certain exception criteria will be exempted from following a voltage schedule. Those generators will receive an exemption letter annually in lieu of a seasonal voltage schedule.

7.2 Voltage for Loads - It is the responsibility of the interconnecting facility owner to incorporate appropriate voltage regulation equipment in their facility if the interconnecting facility's supply voltage requirements are more restrictive than a range from .95 to 1.05 per unit of nominal voltage.

7.3 Reactive Power/Power Factor for Generator - The interconnected generator shall be designed and operate to maintain a composite power delivery at the continuous rated power output at a power factor between 0.95 lagging and 0.95 leading.

7.4 Reactive Power/Power Factor for Load - The interconnected facility shall be responsible for providing their own reactive power needs in order to maintain a power factor between 0.95 lagging and 0.95 leading. All reactive resources shall be capable of operating within the voltage limits stated in the current NERC Standards for normal and emergency conditions. Switched reactive resources shall be designed to not cause.

8. POWER QUALITY IMPACTS

8.1 Power Quality - Adequate design precautions shall be taken by the interconnected facility owner to prevent excessive and deleterious harmonic voltages and/or currents from occurring on the OG&E system. The interconnected facility shall be designed to operate with normal harmonic voltage and currents that originate from OG&E. Voltage and current harmonic levels need to be below the stated values in the current IEEE Standard 519 document and any successor IEEE Standards. Excessive harmonics originating from within the interconnected facility will be the responsibility of the interconnected facilityowner to correct at their own expense.

8.2 Voltage Flicker - Voltage surges or flicker caused by the operation, synchronization, or isolation of the interconnected facility shall be within the standards set forth in the IEEE 1453-2004 voltage flicker curves. The interconnected facility shall provide suitable equipment to limit voltage flicker to below the "Border Line of Visability" curve on the IEEE voltage flicker chart at the point of interconnection.

8.3 Owner shall be responsible for providing, owning, installing and maintaining their electrical System, equipment and process designed to operate and conform with all applicable standards and codes including, but not limited to IEEE Standards 519-1992 and IEEE 141-1993 (borderline Visibility curve) and any successor IEEE Standards.[1]

[1] IEEE 519 is the harmonics standard, IEEE 141 is the traditional flicker standard.

8.4 For Arc Furnace connections:

8.4.1 Owner shall be responsible for providing, owning, installing and maintaining their electrical system, equipment and process designed to operate and conform with all applicable standards and codes including, but not limited to IEEE Standards 519-1992 and IEEE 1453-2004 and any successor IEEE Standards.[2]

8.4.2 Owner will be responsible for specifying the SVC that will meet the IEEE 1453 guidelines based on the fault current values as provided by the Company. The Consumer will operate the equipment at the Consumer's facility to meet the IEEE 1453 guidelines as measured with an IEEE compliant flicker meter at the point of common coupling (PCC) which is the 138 kV bus at Mclean substation, specifically a Perception of Flicker Short Term (Pst.) of .8 and a Perception of Flicker Long Term (Plt.) of 0.6..

8.5 OG&E policy requires adherence to the latest revision of the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547, Standard for Interconnecting Distributive Resources with Electric Power Systems, IEEE Std. 1547.2, the accompanying application guide and any successor IEEE Standards., and the Oklahoma Administrative Code, Title 165. Corporation Commission Chapter 35: Electric Utility Rates and Chapter 40: Standard Terms of Purchases from Purchasers of 100 KW or Less (where applicable).

9. EQUIPMENT RATINGS

9.1 Equipment ratings shall be suitable for the ambient temperature range of -40° C to 50°C. Equipment ratings shall be sized for load and system expansion for the 20-year time frame. Equipment ratings shall comply with the latest ANSI, IEEE, NEMA, and NERC requirements. and shall be in accordance with the OG&E Construction Standards, Engineering and Design Guides.

9.2 Power transformers, breakers, coupling capacitive voltage transformers (CCVT), wave traps, potential transformers (PT), current transformers (CT), air break disconnect switches and other associated equipment shall be specified in accordance with the OG&E Construction Standards, Engineering and Design Guides.

10. SYNCHRONIZING OF FACILITIES

Synchronization of an interconnected generator shall be accomplished by providing suitable equipment to measure both the phase angle across the breaker and the voltage on each side of the breaker. The phase rotation shall be slowed to a near stop condition and the phase angle reduced to 10 degrees or less before interconnection is made. Under no circumstances shall OG&E alter bus voltage to allow synchronization of the interconnecting party's generator.

11. MAINTENANCE COORDINATION

11.1 Obligations – OG&E and the interconnecting party shall maintain their facilities in a safe and reliable manner in accordance with Good Utility Practice.

[2] IEEE 519 is the harmonics standard, IEEE 1453 is the flicker standard for Arc Furnaces.

11.2 Coordination - OG&E and the interconnecting party shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the interconnecting facilities.

11.3 Secondary Systems – OG&E and the interconnecting party shall cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of the interconnecting facilities and equipment which may reasonably be expected to impact the other party. OG&E and the interconnecting party shall provide advance notice to the other party before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

12. OPERATIONAL ISSUES

12.1 Abnormal Frequency Conditions -- It shall be the responsibility of the interconnecting facility owner to provide adequate protection or safeguards to prevent damage to OG&E caused by over/under frequency originating in the interconnected facility. The interconnecting facility owner shall provide adequate protection and safeguards to protect the interconnected facility from inadvertent over/under voltage conditions originating from the OG&E electrical system. Steady-state voltages shall be maintained within the normal and emergency limits as defined in the current NERC Standards.

12.2 Abnormal Frequency Conditions Specific for Generators – the transmission system is designed to automatically activate a load shed program in the event of an under-frequency system disturbance. The interconnected generator shall implement under and over frequency relay set points to endure “ride through” capability of the transmission system. The generator’s response to frequency deviations of pre-determined magnitudes shall be studied and coordinated with OG&E.

12.3 Generator Frequency Control - A speed governor system is required on all synchronous generators. The governor regulates the output of the generator as a function of the system frequency. That function shall be coordinated with the governors of other resources, all located within the same control area, to assure proper system response to frequency variations. The speed governor shall incorporate droop control.

12.4 Abnormal Voltages - It shall be the responsibility of the interconnecting facility owner to provide adequate protection or safeguards to prevent damage to OG&E caused by over/under voltages originating in the interconnected facility. The interconnecting facility owner shall provide adequate protection and safeguards to protect the interconnected facility from inadvertent over/under voltage conditions originating from the OG&E electrical system. Steady-state voltages shall be maintained within the normal and emergency limits as defined in the current NERC Standards.

13. INSPECTION REQUIREMENTS FOR EXISTING OR NEW FACILITIES

13.1 Pre In-service Operation Testing and Inspection - Prior to the new interconnection facilities being placed in service, OG&E may inspect, test, or witness the testing of the interconnecting facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. OG&E and the interconnecting party shall make any modifications to its facilities that are found to be necessary as a result of such testing. The interconnecting party shall bear the cost of all such testing, inspection, and modifications.

13.2 Post In-service Operation Date Testing and Modifications – OG&E and the interconnecting party may perform routine inspection and testing of its interconnecting facilities and equipment in accordance with Good Utility Practice and NERC/FERC requirements as may be necessary to ensure the continued interconnection of the new facility in a safe and reliable manner. Both OG&E and the interconnecting party shall have the right, upon advance written notice, to request additional testing of the other's interconnecting facilities.

13.3 Advance Notice - Both OG&E and the interconnecting party shall notify the other party in advance of its performance of tests of the interconnecting facilities. The other party has the right, at its own expense, to observe such testing.

13.4 Right to Inspect – OG&E and the interconnecting party shall have the right, but shall have no obligation to:

- observe the other party's tests and/or inspection of any of its system protection facilities and other protective equipment;
- review the settings of the other party's system protection facilities and other protective equipment; and
- review the other party's maintenance records relative to the interconnection facilities, the system protection facilities and other protective equipment.

13.5 Exercise rights - OG&E and the interconnecting party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other party. The exercise or non-exercise by a party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the interconnection facilities or the system protection facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same.

14. COMMUNICATIONS AND PROCEDURES

14.1 General -- Operational communications between in the interconnected facility and the OG&E Transmission Control Center shall be active and maintained under both normal and emergency conditions.

14.2 Normal Conditions -- include, but not limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

14.3 Emergency Conditions -- are events or scenarios in which immediate action shall be taken to ensure safety, prevent equipment damage, or jeopardize the reliability of the OG&E or interconnected party's system.

14.4 Failure of Communications -- Emergency telecommunications conditions may develop that affect telecommunications equipment with or without directly affecting power transmission system facilities. Therefore, the interconnecting facility owner shall provide equipment redundancy and telecommunications route redundancy to protect against certain kinds of failure and telecommunications path interruption. A repair team dedicated to the telecommunications of the interconnecting facility shall be retained along with an adequate supply of spare components. In the event of a failure of Interpersonal Communications (Primary Phone Lines), the interconnecting facility owner shall contact the OG&E Transmission Control Center to inform them of the outage and provide the contact information of their Alternative Interpersonal Communications (Backup Phone Lines), consistent with NERC Reliability Standard COM-001-2.

14.5 Backup Communications Strategy – Where commercial, public telephone network facilities or services support important power system telecommunications, a backup strategy shall be developed by the Requester to protect against interruption of such services. Backup methods could include redundant services, self-healing services, multiple independent routes, carriers and combinations of independent facilities such as wireline and cellular, fiber and radio, etc. Backup telecommunications system equipment such as emergency standby power generators with ample on-site fuel storage and reserve storage battery capacity shall be incorporated in critical telecommunications facilities. Backup equipment shall also be considered for certain non-critical telecommunications to provide continued operation of telecommunications during interruption of transmission services. The interconnecting facility owner shall provide the OG&E Transmission Control Center the contact information for their Alternative Interpersonal Communications (Backup Phone Lines) along with their Interpersonal Communications (Primary Phone Lines), consistent with NERC Reliability Standard COM-001-2.

Attachment B

Facility Interconnection Studies

OG&E and SPP shall coordinate in the study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) materially modifying existing interconnections of generation, transmission, or electricity end-user Facilities. The following shall be studied:

1.1. The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s);

1.2. Adherence to applicable NERC Reliability Standards; regional and Transmission Owner planning criteria; and Facility interconnection requirements;

1.3. Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and

1.4. Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.

Plan to Achieve Required System Performance

The impact of the interconnection customer on the reliability of the interconnected transmission system shall be evaluated. Studies are performed by SPP in conjunction with OG&E and in accordance with established NERC, SPP and OG&E Transmission Planning Criteria.

Generator Interconnection (GI) requests must proceed through the SPP generator interconnection process. Generator Interconnection Procedures (GIP) are detailed in Attachment V of the SPP OATT. Three levels of system studies are defined in the GIP; 1) Feasibility, 2) System Impact, and 3) Facilities. These series of studies are performed to determine the impact of the generator interconnection request on the transmission system. The study results include identification of solutions to any identified reliability violations. The results of these targeted studies are posted to the SPP website.

Transmission interconnections are analyzed as SPP performs annual studies to evaluate transmission system reliability as part of its Integrated Transmission Planning (ITP) process. As part of the evaluation process it may be determined that there is a need for additional system reliability support across multiple interconnected transmission owner facilities. Solutions to identified reliability issues are developed by the affected transmission owners in coordination with SPP. The study results and resultant solutions identified are documented in the annual SPP Transmission Expansion Plan (STEP) and posted to the SPP website. Transmission Owner to Transmission Owner interconnections are evaluated in accordance with SPP Planning Criteria 3.5 and Appendix 11.

End-User interconnection requests are evaluated by OG&E to determine if any system reliability impacts may result from the interconnection of the customer to the transmission system. Studies are primarily conducted to determine if there is available capacity at the interconnection point to accommodate the request. If additional system reinforcements are identified during the study the results will be made known to the EU and solutions will be proposed to address the issue. Load additions will be submitted to SPP to be evaluated as part of the Attachment AQ process of the OATT.

- **Procedures for Coordinated Joint Studies**

  OG&E is a member of SPP Regional Transmission Organization (RTO). One of the many functions of SPP is to coordinate joint studies of new facilities and their impacts on the interconnected transmission system. OG&E actively participates in this process. The process is described in the SPP OATT which is available on the SPP website.

  The SPP OATT includes attachments that define the data requirements for interconnection Feasibility and System Impact Studies. Generators and Transmission interconnection customers should refer to the SPP OATT for specifics. Data is to be submitted as provided in the SPP OATT.

Study results associated with individual generation and merchant transmission facility requests are posted by SPP to the SPP website. For End-Users interconnection to the OG&E transmission system, applicable study results regarding feasible interconnection alternatives will be provided to the requestor.

For transmission interconnection, summary study results are published by SPP annually as part of the SPP Transmission Expansion Plan (STEP).

Interconnection planning studies are conducted to meet the criteria established within NERC Transmission Planning Reliability Standards—the TPL series, SPP OATT, and the SPP Planning Criteria. Copies of the applicable planning standards are available on the NERC website and SPP website.

Study Process Enhancements: TPs and PCs should improve their study processes for both interconnection studies and annual planning studies to ensure they are appropriate for a BPS with significantly more BESS and hybrid power plants. Determination of stressed operating conditions, selection of study assumptions, inclusion of various modeling practices, and determination of appropriate dispatch conditions are just a few areas where close attention will be needed by TPs and PCs to ensure their study approaches align with the new technologies.

Expansion of Study Conditions: The variability and uncertainty of renewable energy resources has led TPs and PCs to study different expected operating conditions than were previously used for planning assessments. BESS and hybrid plants may help address some of the operational variability; however, developing suitable and reasonable study assumptions will become a significant challenge for future planning studies. TPs and PCs may need to expand the set of study conditions used for future planning assessments as the most severe operating conditions may change over time.

- **Procedures for Notification**

Any additions or modifications to existing facilities that have the potential to affect an interconnection require the customer to notify OG&E as soon as feasible. OG&E will assess the potential impact of the modifications and contact the appropriate affected parties. The significance of any impact has the potential to vary over a broad range. Changes that could affect the operating limits on the interconnected system may require engineering studies and the involvement of SPP. Changes that modify power output must follow the requirements of SPP OATT.

- **Procedures for Confirmation**

Along with the notification process outlined above, OG&E will also require the customer to obtain from the SPP, evidence that the additions or modifications to existing facilities are within SPP BA's metered boundaries, and provide that evidence to OG&E.

Overview of Regional Planning Process

In accordance with SPP Tariff Attachment O – Transmission Planning Process, the SPP's transmission planning process is an open process. New and proposed transmission facilities can come from several different areas of the Tariff. These areas are:
1) transmission service requests; 2) Generation Interconnection Service requests; 3) the integrated transmission planning process (ITP Upgrades); 4) the Balanced Portfolio process; 5) the high priority study process (high priority upgrades); 6) requests for Sponsored Upgrades; and 7) the evaluation of proposed Interregional Projects.

Transmission Interconnection:

In accordance with SPP Tariff Attachment Z1 – Aggregate Transmission Service Study Procedures, new transmission facilities and transmission facility upgrades must be included in the Aggregate Transmission Service Study process. Eligible Customers that submitted a Completed Application for transmission service during the open season specified in Section II of Attachment Z1 must submit an Aggregate

Facilities Study Agreement (AFSA) to the SPP prior to the close of the open season. The AFSA shall be available on the SPP OASIS. By executing the AFSA, the Eligible Customer agrees to reimburse the SPP and any affected Transmission Owner(s) for its share of costs for any required Aggregate Facilities Studies as described in Attachment Z1. For each Aggregate Facilities Study, SPP shall identify system constraints and, in conjunction with the applicable Transmission Owner(s), determine any upgrades required to reliably provide the requested transmission service for the study group in a manner that minimizes the overall costs for the study group. In identifying the required upgrades, SPP shall perform a regional review to determine if alternative solutions would reduce overall cost to customers and incorporate such solutions as appropriate. The power flow models used for an Aggregate Facilities Study shall be developed for each season for the period from the earliest start of service to the latest end of service for the applicable requests.

Generator Interconnection:

In accordance with SPP Tariff Attachment V – Generator Interconnection Procedures, an Interconnection Customer shall submit to SPP an Interconnection Request in the form of Appendix 1 to the GIP and the deposit along with the other items in Section 3.3.1 of the Generator Interconnection Procedures. SPP shall apply the deposit toward the cost of the applicable Interconnection Study. Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. Interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site. An Interconnection Request to evaluate one site at two different voltage levels shall be treated as two Interconnection Requests.
At Interconnection Customer's option, Transmission Provider and Interconnection Customer will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point(s) of Interconnection to be studied no later than the execution of the Interconnection Feasibility Study Agreement.

SPP will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System Operators and, if possible, include those results (if available) in its applicable Interconnection Study within the time frame specified in the GIP. SPP will include such Affected System Operators in all meetings held with Interconnection Customer as required by the GIP. Interconnection Customer will cooperate with SPP in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

End User Interconnection:

In accordance with SPP Tariff Attachment AQ – Delivery Point Addition Process, the Transmission Customer shall make requests for changes in local delivery facilities, including facility upgrades, retirements and replacements, or the establishment of any new delivery point in writing to (a) the Transmission Provider (SPP) and the Host Transmission Owner as specified in Section 20 of the Network Operating Agreement or to (b) the Transmission Provider (SPP) as specified in Section 8 of the Point to Point Transmission Service Agreement, as applicable.

The Host Transmission Owner will determine whether the request can be included in the SPP Integrated Transmission Planning (“ITP”) processes within 10 business days of receiving the request from the Transmission Customer or in agreed upon timeframe.

- If the Host Transmission Owner determines that the request can be included in the ITP processes, the delivery point and necessary transmission facilities would then be migrated into the SPP planning models (TOs input data into Model on Demand tool) which then feeds into the annual Attachment O reliability planning processes. SPP will update any corresponding Network Integration Transmission Service Agreements (“NITSA”), as required.
- If the request involves a Network Resource change or a transfer of a delivery point, the request should be included in the SPP Aggregate Transmission Service Study process (Attachment Z1) and/or Delivery Point Transfer Screening Study process (Attachment AR), as applicable.
- If the request cannot be included in the ITP process, Aggregate Transmission Service Study or Delivery Point Transfer Screening Study, then the request should be processed through the Attachment AQ process.

The Host Transmission Owner will perform a screening study within 30 calendar days of receiving the request from the Transmission Customer and determine whether a Load Connection Study (LCS) is required. The Host Transmission Owner shall have the option of billing the cost of the screening study to the Transmission Customer. If a LCS is not required, Host Transmission Owner shall jointly notify Transmission Customer and SPP within 10 business days of the completion of the screening study. The delivery point and any necessary interconnection or sponsored facilities are then added to the SPP planning models which then feeds into the annual Attachment O reliability planning processes.

If the Host Transmission Owner determines that a LCS is required, the Host Transmission Owner shall tender the LCS Agreement to the Transmission Customer within 10 business days. The Transmission Customer must execute the LCS Agreement and provide the deposit, if required, within 30 calendar days. The Host Transmission Owner shall perform the LCS and provide the draft LCS Report to SPP and the Transmission Customer within 60 calendar days of the LCS Agreement execution.

Following receipt of the draft LCS Report, SPP will perform an initial assessment based on the Host Transmission Owner’s draft LCS Report to determine whether a Delivery Point Network Study (DPNS) is required. SPP and Host Transmission Owner will coordinate results of that assessment with the Transmission Customer. If SPP and the Host Transmission Owner agree to the results of that assessment, SPP will note such agreement in the LCS report.

If SPP determines that a DPNS is required, or if the Transmission Customer requests a DPNS, SPP shall provide the DPNS Agreement to the Transmission Customer within 5 business days following SPP’s determination or Transmission Customer’s request. The DPNS Agreement shall commit the Transmission Customer to pay SPP for the actual cost to complete the study. SPP will perform the DPNS and will post the DPNS Report within 60 calendar days of the receipt of an executed DPNS Agreement.

If SPP determines that a DPNS is not required, the Host Transmission Owner shall provide the final LCS Report to the Transmission Customer and SPP. SPP shall post the final LCS Report on the SPP website within 10 business days of receipt from the Host Transmission Owner.

Attachment C

Wind Farm Modeling Data Request

Failure to submit this data will result in delays in energization.

The purpose of this document is to gather design data necessary to accurately model a wind farm in the Power System Simulation for Engineers (PSS/E) software, as well as Computer-Aided Protection Engineering (CAPE) software. This is required to maintain compliance with applicable NERC Reliability Standards. Interconnection customers are required to either fill out the data requested in this document. If a design change occurs during construction that affects the data requested in this document, an update shall be sent to OG&E detailing the changes. It is also encouraged to review the Southwest Power Pool's modeling requirements in the Model Development Working Group (MDWG) Procedure Manual which can be found on the Southwest Power Pool's Website, SPP.org, or through an internet search.

This form is used for data submission to OG&E only. OG&E cannot submit data to SPP on behalf of the wind farm unless a "Letter of Notice" has been sent to SPP. Please contact OG&E for a copy of the Letter of Notice if you would like for OG&E to submit the initial modeling data to SPP.

Wind Farm Name: ___________________
Planned In-Service Date: ___________
SPP Generation Interconnection Study ID: GEN-20XX-XXX

Background:
The Bulk Electric System models utilize an equivalent representation of wind farms. Collector system's wind turbine generators, wind turbine generator step-up transformers, and feeders connecting to the same main power transformer are equivalized and modeled as shown in Figure 1 below. If more than one main power transformer (MPT) is used, then additional collection system equivalents will be required for each MPT.

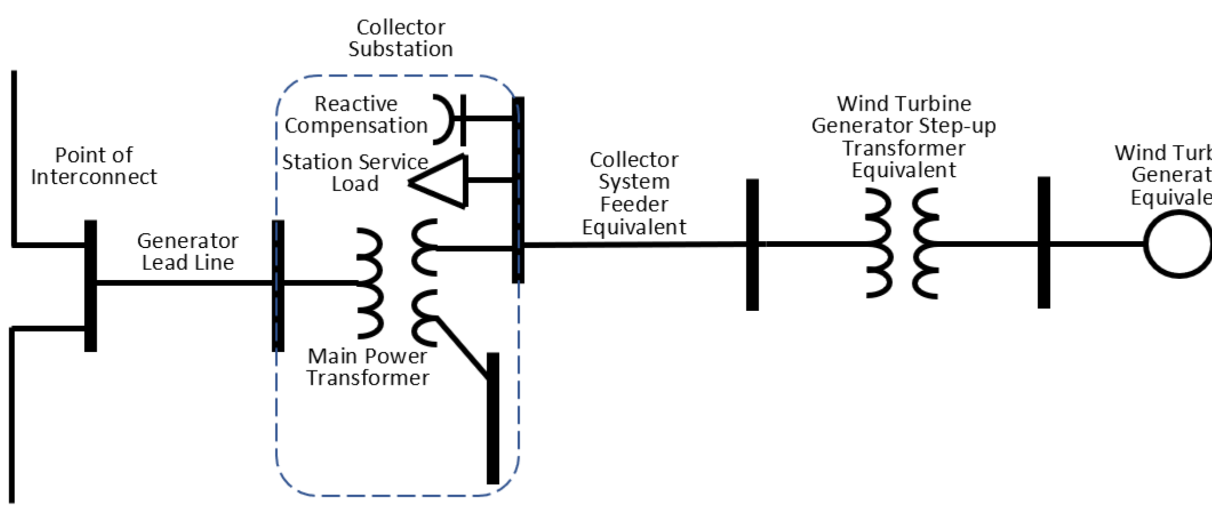

Figure 1 - Example Wind Farm Equivalent

Wind Turbine Generator:

Please provide the data as an equivalent representation as shown in figure 1 above unless otherwise specified. Add/Remove additional tables as needed.

Collector 1 - Generator 1		
Wind Turbine Manufacturer and Model		--
Turbine Type (1-5)	Choose an item.	--
Total Real Power Capability		MW
Number of Wind Turbines		
Control Mode for Reactive Power Capability	Choose an item.	--
Power Factor (+/-) or Maximum/Minimum Reactive Power Capability		
Machine MVA base of Single Wind Turbine		MVA
Unsaturated Sub-Transient Impedance (R+jX''d on single machine MVA base)		Per Unit
Unsaturated Transient Reactance (X'd on single machine MVA base)		Per Unit
Synchronous Reactance (Xd on single machine MVA base)		Per Unit
Negative Sequence Impedance (R+jX on single machine MVA base)		Per Unit
Zero Sequence Impedance (R+jX on single machine MVA base)		Per Unit

Collector 2 - Generator 1		
Wind Turbine Manufacturer and Model		--
Turbine Type (1-5)	Choose an item.	--
Total Real Power Capability		MW
Number of Wind Turbines		
Control Mode for Reactive Power Capability	Choose an item.	--
Power Factor (+/-) or Maximum/Minimum Reactive Power Capability		
Machine MVA base of Single Wind Turbine		MVA
Unsaturated Sub-Transient Impedance (R+jX''d on single machine MVA base)		Per Unit
Unsaturated Transient Reactance (X'd on single machine MVA base)		Per Unit
Synchronous Reactance (Xd on single machine MVA base)		Per Unit
Negative Sequence Impedance (R+jX on single machine MVA base)		Per Unit
Zero Sequence Impedance (R+jX on single machine MVA base)		Per Unit

Wind Turbine Generator Step-up Transformer (WTGSU):

Please provide the data as an equivalent representation as shown in figure 1 above. Add/remove additional tables as needed.

Collector 1 - WTGSU Equivalent 1		
Primary Winding Voltage		kV
Secondary Winding Voltage		kV
Base MVA		MVA
Exciting Current		Per Unit
No Load Losses		Watts
Winding Angle/Phase Shift		degrees
Impedance/Load Losses (on transformer base) *		
	R(pu) or Z(pu) (please specify)	X(pu) or Loss (kW) (please specify)
Positive Sequence		
Zero Sequence		
Primary Winding Tap Settings		
Number of Tap Positions		Taps
Highest/Lowest Tap Position Voltage (Rmax/Rmin)	/	kV/kV or p.u./p.u.
Control Mode	Choose an item.	
If locked – tap position voltage		kV or p.u.
If automatic – High Voltage/Low Voltage Setting (Vmax/Vmin)	/	p.u./p.u.
If automatic - Which bus is the ULTC trying to control? (example: High Voltage Bus at Collector)		
Secondary Winding Tap Settings		
Number of Tap Positions		Taps
Highest/Lowest Tap Position Voltage (Vmax/Vmin)	/	kV/kV or p.u./p.u.
Control Mode	Choose an item.	
If locked – tap position voltage		kV or p.u.
If automatic – High Voltage/Low Voltage Setting	/	p.u./p.u.
If automatic - Which bus is the ULTC trying to control? (example: High Voltage Bus at Collector)		

*impedances may be converted to system base (100MVA) for BES models

Collector 2 - WTGSU Equivalent 1		
Primary Winding Voltage		kV
Secondary Winding Voltage		kV
Base MVA*		MVA
Exciting Current		Per Unit
No Load Losses		Watts
Vector Group or Winding Angle		degrees
Impedance/Load Losses (on transformer base) *		
	R(pu) or Z(pu) (please specify)	X(pu) or Loss (kW) (please specify)
Positive Sequence		
Zero Sequence		
Primary Winding Tap Settings		
Number of Tap Positions		Taps
Highest/Lowest Tap Position Voltage (Rmax/Rmin)	/	kV/kV or p.u./p.u.
Control Mode	Choose an item.	
If locked – tap position voltage		kV or p.u.
If automatic – High Voltage/Low Voltage Setting (Vmax/Vmin)	/	p.u./p.u.
If automatic - Which bus is the ULTC trying to control? (example: High Voltage Bus at Collector)		

Secondary Winding Tap Settings		
Number of Tap Positions		Taps
Highest/Lowest Tap Position Voltage (Vmax/Vmin)	/	kV/kV or p.u./p.u.
Control Mode	Choose an item.	
If locked – tap position voltage		kV or p.u.
If automatic – High Voltage/Low Voltage Setting	/	p.u./p.u.
If automatic - Which bus is the ULTC trying to control? (example: High Voltage Bus at Collector)		

*impedances may be converted to system base (100MVA) for BES models

Collector System Feeder Equivalent:

Please provide the data as an equivalent representation as shown in figure 1 above. Add/remove additional tables as needed. Impedance data may also be provided in per unit on 100MVA system base. If data is provided in per unit, please update the units in the table(s) below.

Collector 1 - Feeder Equivalent		
Collection Network Voltage (kV_{LL})		kV
Length		Miles
Positive Sequence Impedance (R+jX)		Ohms
Positive Sequence Admittance (B)		µS
Zero Sequence Impedance (R+jX)		Ohms
Zero Sequence Admittance (B)		µS

Collector 2 - Feeder Equivalent		
Collection Network Voltage (kV_{LL})		kV
Length		Miles
Positive Sequence Impedance (R+jX)		Ohms
Positive Sequence Admittance (B)		µS
Zero Sequence Impedance (R+jX)		Ohms
Zero Sequence Admittance (B)		µS

Station Service/Auxiliary Load:

If this section is not applicable, please type N/A here:

Collector 1 Station Service/Aux Load		
Real Load		MW
Reactive Load		MVAR

Collector 2 Station Service/Aux Load		
Real Load		MW
Reactive Load		MVAR

Reactive Compensation:

If this section is not applicable, please type N/A here:

Collector 1 - Reactive Compensation		
Control Mode	Choose an item.	--
High Voltage/Low Voltage Setting (voltage controlled only)	/	p.u./p.u.
Capacitor		
Quantity/Number of Block Steps		--
Size of Individual Block		MVAR
Reactor		
Quantity/Number of Block Steps		--
Size of Individual Block		MVAR

Collector 2 - Reactive Compensation		
Control Mode	Choose an item.	--
High Voltage/Low Voltage Setting (voltage controlled only)	/	p.u./p.u.
Capacitor		
Quantity/Number of Block Steps		--
Size of Individual Block		MVAR
Reactor		
Quantity/Number of Block Steps		--
Size of Individual Block		MVAR

Main Power Transformer:

Add/remove additional tables as needed.

Main Power Transformer 1		
Primary Winding Voltage (center tap)		kV
Secondary Winding Voltage (center tap)		kV
Tertiary Winding Voltage		kV
Tertiary Winding Angle or Transformer Vector Group		degrees
Autotransformer? (yes or no)		--
Base MVA*		MVA
Exciting Current		Per Unit
No Load Losses		Watts
Impedance/Load Losses (on transformer base*)		
	R(pu) or Z(pu) (please specify)	X(pu) or Loss (kW) (please specify)
Positive Sequence Impedance (P-S)		
Positive Sequence Impedance (S-T)		
Positive Sequence Impedance (P-T)		
Zero Sequence Impedance (P-S)		
Zero Sequence Impedance (S-T)		
Zero Sequence Impedance (P-T)		
Grounding Resistor/Reactor on Secondary Winding		
Grounding Impedance		ohm
Primary Winding Tap Settings		
Number of Tap Positions		Taps
Highest/Lowest Tap Position Voltage (Vmax/Vmin)	/	kV/kV or p.u./p.u.
Control Mode	Choose an item.	
If locked – tap position voltage		kV or p.u.
If automatic – High Voltage/Low Voltage Setting	/	p.u./p.u.
If automatic - Which bus is the ULTC trying to control? (example: High Voltage Bus at Collector)		
Secondary Winding Tap Settings		
Number of Tap Positions		Taps
Highest/Lowest Tap Position Voltage (Rmax/Rmin)	/	kV/kV or p.u./p.u.
Control Mode	Choose an item.	
If locked – tap position voltage		kV or p.u.
If automatic – High Voltage/Low Voltage Setting (Vmax/Vmin)	/	p.u./p.u.
If automatic - Which bus is the ULTC trying to control? (example: High Voltage Bus at Collector)		

*impedances may be converted to system base (100MVA) for BES model

Main Power Transformer 2		
Primary Winding Voltage (center tap)		kV
Secondary Winding Voltage (center tap)		kV
Tertiary Winding Voltage		kV
Tertiary Winding Angle or Transformer Vector Group		degrees
Autotransformer? (yes or no)		--
Base MVA*		MVA
Exciting Current		Per Unit
No Load Losses		Watts
Impedance/Load Losses (on transformer base*)		
	R(pu) or Z(pu) (please specify)	X(pu) or Loss (kW) (please specify)
Positive Sequence Impedance (P-S)		
Positive Sequence Impedance (S-T)		
Positive Sequence Impedance (P-T)		
Zero Sequence Impedance (P-S)		
Zero Sequence Impedance (S-T)		
Zero Sequence Impedance (P-T)		
Grounding Resistor/Reactor		
Grounding Impedance		ohm
Primary Winding Tap Settings		
Number of Tap Positions		Taps
Highest/Lowest Tap Position Voltage (Rmax/Rmin)	/	kV/kV or p.u./p.u.
Control Mode	Choose an item.	
If locked – tap position voltage		kV or p.u.
If automatic – High Voltage/Low Voltage Setting (Vmax/Vmin)	/	p.u./p.u.
If automatic - Which bus is the ULTC trying to control? (example: High Voltage Bus at Collector)		
Secondary Winding Tap Settings		
Number of Tap Positions		Taps
Highest/Lowest Tap Position Voltage (Vmax/Vmin)	/	kV/kV or p.u./p.u.
Control Mode	Choose an item.	
If locked – tap position voltage		kV or p.u.
If automatic – High Voltage/Low Voltage Setting	/	p.u./p.u.
If automatic - Which bus is the ULTC trying to control? (example: High Voltage Bus at Collector)		

*impedances may be converted to system base (100MVA) for BES model

Generator Lead Line:

Impedance data may also be provided in per unit on 100MVA system base.

Generator Lead Line		
Conductor		
Length		Miles
Positive Sequence Impedance (R+jX)		p.u.
Positive Sequence Admittance (B)		p.u.
Zero Sequence Impedance (R+jX)		p.u.
Zero Sequence Admittance (B)		p.u.

Wind Farm Facility Ratings:

In addition to requiring information to accurately model all the relevant wind farm equipment in PSS/E, a thermal rating must be provided by the interconnect customer to assign to all the wind farm's facilities (series elements modeled in PSS/E). These ratings should take into account, but are not limited to conductor, jumpers, bus, switch, breaker, CTs, and line relay limits. Once these are determined, a "most limiting" piece of equipment should be identified. This will be used to determine the overall rating for each section of a facility. A facility ratings sheet for the windfarm may be submitted in place the ratings section in this information request if the facility ratings sheet contains all of the required data.

Notes:

- The wind farm must be able to operate at full output using the "Normal Ratings" specified in the table below. For example, the "base rating" of a power transformer should only be listed as the Normal Rating of that piece of equipment if the full MVA output of the wind turbines connected to it can never exceed it.
- Interruptible current rating of equipment should not be used as an emergency rating.

Overall Equipment Ratings	**Summer Normal Rating (MVA)**	**Summer Emergency Rating (MVA)**	**Winter Normal Rating (MVA)**	**Winter Emergency Rating (MVA)**
Collector 1 - WTGSU Equivalent 1				
Collector 2 - WTGSU Equivalent 1				
Collector 1 - Feeder Equivalent				
Main Power Transformer 1 (Pri/Sec/Tert)				
Main Power Transformer 2 (Pri/Sec/Tert)				
Generator Lead Line				

**add additional rows as needed

Wind Turbine Dynamic Data:

The information required to accurately model the dynamic performance of the aggregate wind farm and any low voltage ride through (LVRT) considerations is listed below. This data (through a dyre file) should be provided for the industry standard PSS/E version 34.6.1 second generation renewable energy dynamic models (REGCAU1, REECxU1, etc.) as outlined in the SPP MDWG Acceptable Model Guidelines.pdf (attached).

2020 MDWG Acceptable Model G

Acceptable_Models _List_-_2020-1-30.xls

Additional information regarding renewable energy dynamic models can be found here:

- EPRI: Model User Guide for Generic Renewable Energy System Models
- WECC Second Generation Wind Turbine Models (Note: Not all WECC approved models are SPP approved models)

Bus numbers used in PSS/E dyre files for the equivalized wind farm will be provided by OG&E upon request. Turbine dyre information should be provided for the lumped generator on each equivalent collector as shown in Figure 1.

Renewable Energy Dynamic Model	
Turbine Type (Type 3, Type 4, etc.)	
Plant Control Model Used (REPCAU1, REPCTAU1, etc.)	
Wind Turbine Dynamic Model Parameters	(Please Attach Dyre File)

Generator under-voltage (LVRT) and over-voltage limits should be implemented for all instantaneous and timed limitations of the wind turbines using standard PSS/E voltage tripping models. Voltage ride-through should comply with the "No Trip Zone" of PRC-024 Attachment 2 "Voltage Ride-Through Time Duration

Curve", if applicable.

Voltage Tripping Models to Implement Voltage Limits	
Library Model Name (VTGDCAT, VTGTPAT, etc.)	
Voltage Tripping Model Parameters	(Please Attach Dyre File)

Other Control Mechanisms or Circuits:

The interconnection customer should also provide complete descriptions of, and diagrams of any pertinent control scheme with operational limits and set-points that alter or change the characteristics, or status of the wind generator during a system disturbance, or a change in operating conditions.

Diagrams:

Please provide a One-Line Diagram of the collector substation.

Geomagnetic Disturbance Data:

Latitude and longitude shall be in decimal degrees with at least three decimal precision (e.g., 45.001) for each substation that includes equipment operated at 200kV and above. Only positive decimal degree values between 25°N and 50°N latitude (e.g., 25.000 to 50.000) and longitudes to the west of the Prime Meridian between 85°W and 115°W (e.g., -85.000 to -115.000) are acceptable. Substation grounding resistances shall be submitted in Ohms with at least one decimal precision (e.g., 0.2 Ohms) or, in the rare instance when a substation is ungrounded, as "-1".

Latitude	**Longitude**	**Grounding Resistance (ohms)**

Attachment D

OG&E Distributed Resources Interconnection Guidelines
(refer to attached pdf)

OG&E DR
Interconnection Guide

Change History

Revision No	Description of Changes	Revised By	Approved By	Date
0	New document	Transmission Planning Staff		10/6/2005
1	General Updates and addition of APPENDIX C - Wind Farm Modeling Data Request	Transmission Planning Staff	Hardebeck	4/29/2015
2	General Updates, Remove existing Appendix A & B, add new Attachment A - Facility Connection Specifications and new Attachment B - Facility Interconnection Studies, rename Appendix C to "Attachment C."	Transmission Planning Staff	Hardebeck	12/18/2015
3	Changes: • Updated reference to current SPP Planning Criteria. • Corrected references to SPP Tariff Attachments in the End User Interconnection section. • Updated Appendix C • Added new Appendix D. • Updated document to reflect compliance to revised FAC-001-3 (in Attachment B).	Transmission Planning Staff	Hardebeck	5/1/2018
4	Changes: • Updated language and formatting section 3.1.2-part H • Updated language and formatting section 4.6 Inverter-Based Resources (IBR) • Updated formatting section 7.7 Models Matching as Built in Controls, Settings and Performance • Updated formatting section 7.8 Software Enhancements • Updated language and formatting in Attachment B Procedures for Coordinated Joint Studies, Study Process Enhancements, and Expansion of Study Conditions	Transmission Planning Staff	Hardebeck	6/15/2021

5	• Added Note to this document's cover page. • Added requirement I to 3.1.2 Transmission Facilities - 60 kV through 138 kV Requirements. • Added requirement H and I to 3.1.3 Transmission Facilities - 161 kV and Higher Requirements.	Transmission Planning Staff	Hardebeck	6/13/2022
6	• Removal of Section 1.7 & 1.8 • Added Requirement 3.1.1 H • Updated formatting throughout document	Transmission Planning Staff	Snapp	7/18/2023