Omaha Public Power District

Customer-Owned Generation Interconnection Manual

Operation of Customer-Owned Generation in Parallel with the Distribution System

This document contains the interconnection requirements for Customer-Owned Generation that operates in parallel with the Omaha Public Power District's Distribution System.

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0.0	2019	JAA	Initial Version
1.0	2020	OPPD	Updated to COG terminology
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1.0 Introduction

Customer owned generators or other electrical resources may be operated in parallel ("Parallel Operation") with the Omaha Public Power District ("District" or "OPPD") electric distribution system (the "Distribution System") pursuant to the submission and approval by OPPD of an Interconnection Application for Customer-Owned Generation, with supporting materials, and execution of OPPD's form Customer-Owned Generation Interconnection Agreement; provided that, the customer-owned generation facility and/or energy storage device(s) meet the requirements of this manual, subject to all applicable statutory and regulatory requirements.

The intention of this document is to ensure the safe and reliable operation of the District's Distribution System for all customers and District personnel.

1.1 Purpose

This guide sets forth the minimum interconnection requirements and procedures for connection and safe operation of customer-owned generation ("COG") in Parallel Operation with the District's Distribution System. For purposes of this Manual, COG shall mean a customer-owned electric generation source that is not directly connected to a bulk power (Transmission) system. COG includes inverter based and synchronous generators and all forms of energy storage technologies capable of exporting active power to facilities that deliver electric power to a load and/or to the Distribution System. Controllable loads used for demand response are not included in the definition of COG.

There may be costs to the owner of the COG (the "Owner") associated with the interconnection. This guide identifies the nature of those costs and establishes a common process for all customers.

An interconnection agreement is a separate form and in no way constitutes an agreement between the Owner and the District for the transaction of energy produced at the customer-owned generation facility, including any necessary interconnection equipment (collectively, the "COG Facility").

In the case where the District and the Owner or the Owner and another entity have a separate agreement for the transaction of energy, the Interconnection Agreement outlined in this document takes precedence as it relates to any and all operational considerations.

1.2 Scope

This guide sets forth the minimum interconnection requirements of customer-owned, single and three phase COG, that operate in parallel with the District's Distribution System at voltages up to and including 15kV (phase to phase). This guide is intended to be supplemental and consistent with the requirements of the current versions of IEEE standard 1547, "Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems interfaces", Federal, State, and Local regulations, and generally accepted industry practices and standards; additional requirements may apply. Unless otherwise indicated or exempted by OPPD, at a minimum, all COG equipment and systems (and their operation) interconnected with the OPPD system shall comply with the latest version of IEEE 1547.

1.3 Limitations

Where necessary, the District may limit the capacity and operating characteristics of COG to avoid the potential for a COG Facility to cause problems with the service of other customers.

COG is not allowed for interconnection with any system of distribution in which the secondary of distribution transformers are connected to a common network for supplying electric power to consumers, commonly referred to as a network secondary distribution system.

OPPD rates and service regulations, and rules of federal, state or local regulatory agencies shall take precedence over these requirements. If this document does not comply with any federal, state or local regulation, then this document shall be superseded by the applicable regulation.

This guide is supplemental to the Omaha Public Power District Facility Connection Guide (NERC FAC-001, located on OPPD's OASIS website) for generation or resources connected to the District Transmission System (>15kV). Refer to the Omaha Public Power District Facility Connection Guide (NERC FAC-001) for base requirements and criteria for an energy resource facility connection to the District's transmission system.

In most cases, COG connected at a Distribution voltage (<15kV) will be restricted from exporting power to the OPPD Transmission system (>15kV).

1.4 Additional Requirements

If the District concludes that an application for Parallel Operation describes facilities that may require additional devices and operating schemes, the District shall make those additional requirements known to the Owner before the application is approved and before interconnection is made.

The District may require historical facility production or load data from the COG Facility Owner to aid in grid planning and operations.

The District may require documentation demonstrating the COG Facility Owner has secured site control for the proposed location of the COG Facility, adequate to commence construction.

1.5 Damages and Liability

The Owner shall use reasonable care not to damage the electrical equipment of the District and shall reimburse the District for damage to the District's equipment resulting from defects in the operation and maintenance of its electrical equipment or resulting from its negligence or that of its agents or employees, and shall indemnify the District against liability for injury or damage suffered by third parties for any such defects and/or negligence.

1.6 Safety

The safety of the general public, District employees and equipment shall in no way be reduced or impaired as a result of the interconnection. In general, the COG Owner shall be responsible to protect OPPD property, public safety, and OPPD personnel from harm due to design flaw, failure, or misoperation of the COG system.

1.7 Application Process

The steps in the process to interconnect COG to the District's Distribution System are located on OPPD.com. OPPD reviews applications on a first-come, first-served basis. They will be reviewed as quickly as possible, but the review process can be subject to delays based on volume.

2.0 Right to Disconnect

The District may disconnect a COG from the Distribution System for any of the following conditions:

1. Expiration, termination or lack of Interconnection Agreement.
2. Non-compliance with the technical requirements.
3. System emergency.
4. Situations when continued Interconnection will endanger persons or property.
5. Routine or emergency maintenance, repairs, or modifications to OPPD's Distribution System.
6. Forced outages.
7. Modification to the COG Facility without approval by OPPD.
8. Continued abnormal operation, substandard operation or inadequate maintenance of the COG Facility.
9. Failure by Owner to maintain a customer account tied to the COG Facility in good standing with OPPD.
10. Failure of Owner to comply with any existing or future regulations, rules, orders or decisions of any governmental or regulatory authority having jurisdiction over the Owner's COG equipment or the operation of such equipment, where failure of compliance would place in jeopardy the personnel or property of the District, or would impact the ability of the District to safely serve its customers, or would pose a threat of sanction or liability to the District.

11. Adverse operating effect of Owner's COG to the District's other electric consumers and/or system as determined by the District.

3.0 System Studies.

The District may, at the Owner's expense, conduct system studies prior to interconnection of a COG Facility. (see Section 5.8 Interconnection Costs).

System studies may include, but are not limited to:

(a) Site visit – A review to determine the system voltage and Interconnection requirements at the proposed site of the COG Facility.

(b) Coordination Study - An engineering analysis that determines whether the presence of COG at a particular location would interfere with the protective fusing and relaying on the Distribution System. It includes a review of the fault current contribution by the COG and the effects on the District's Distribution System.

(c) Distribution System Study – An engineering analysis that models the Distribution System with the proposed COG in place to determine whether the feeder will support the COG without reliability problems or interruptions in service to other customers. The analysis includes a review of the COG contribution to power flow, and the effects on the Distribution System voltage.

(d) Transmission Impact Study - an engineering analysis that models the COG's impact to the transmission system to determine any modifications or upgrades necessary to accomplish the interconnection to the District's facilities. Such a study may be required where there is a possibility of the COG exporting to the transmission system.

(e) Southwest Power Pool Study – any study in accordance with Southwest Power Pool's policies or guidance.

(f) Affected System Study –studies by other utilities that may be affected by interconnection of the Owner's COG. In addition to the costs associated with the studies performed by OPPD, the Owner will also be responsible for study costs of other utilities impacted (or potentially impacted) by the Owner's COG Facility.

4.0 Modifications to District or Owner COG Facilities.

4.1 Changes to District Fault Interruption Equipment

A COG on the Distribution System is an additional source of fault current. Should the District be required to make changes due to the additional fault contribution, the Owner, at the sole discretion of the District, shall have to pay the cost of the required changes. The Owner may also be required to limit the fault current.

4.2 District Changes to Distribution System

If District facilities must be upgraded to enable the Owner to interconnect, then the Owner will be responsible for all costs associated with such service or improvements, as determined by the District.

The Distribution System is a dynamic system. The District reserves the right to make changes from time to time. The Owner may be required to pay for modifications, both to the Owner's and the District's equipment, necessary for reconnecting Owner's COG Facility to the District's reconfigured Distribution System.

See Section 5.8 for additional information regarding Owner costs.

4.3 Owner Changes and Additions to Interconnection

The Owner shall notify the District and obtain approval prior to any proposed modifications to their service entrance, interconnection, or to the approved Interconnection Agreement. The customer should work with their designated Electric Service Designer (see OPPD.com) for modifications to the OPPD electric service.

Changes and/or additions to an existing COG installation require a new application. One-line and site plan drawings must indicate how the new system integrates with the existing system.

4.4 Nontransferable Agreements

Executed Interconnection Agreements, or related documents, are not transferrable to 3rd parties, other COG Facilities or other COG equipment other than those identified in the documents. Changes of COG ownership or modification of COG facilities or equipment voids previously executed agreements. New COG Facility owners do not have District permission by default for closed transition/parallel operation and are subject to disconnection. Customers taking ownership of an existing COG facility or existing COG facility owners intending to make modifications shall contact the District in order to amend any existing Interconnection Agreement. The customer should work with their designated Electric Service Designer for the service, which is listed on OPPD.com.

5.0 Owner Responsibilities

5.1 Design and Installation

The Owner shall be responsible for the design, installation, operation and maintenance of all equipment and the COG Facility installed or that will be installed on the Owner's side of the Point of Interconnection (POI, as hereinafter defined). Such design shall meet the latest standards of American National Standards Institute ("ANSI"), the Institute of Electrical and Electronic Engineers ("IEEE"), National Electrical Code ("NEC"), National Electrical Manufacturers Association ("NEMA"), the National Electrical Safety Code ("NESC"), National Fire Protection Association ("NFPA"), Underwriters Laboratories ("UL"), other national codes, and any local codes pertaining to electrical facility design, construction, or safety. The facility shall be subject to the requirements of all authorities having jurisdiction and shall comply with all applicable codes and ordinances.

When applicable, the District requires a Licensed Professional Electrical Engineer to certify drawings, tests, settings, or other documentation. The professional engineer's seal shall be valid in the state of Nebraska. The Owner should review this manual and coordinate with the District to determine all certification requirements to avoid unnecessary delays.

The Nebraska State Electrical Act governs who qualifies for the planning, layout, or supervision of the installation of wiring, apparatus, or equipment for electrical light, heat, power, and other purposes.

The District reserves the right to field verify the Owner's installed equipment against the submitted Interconnection Application for Customer-Owned Generation.

5.2 Inspection and Tests

When installation of the COG Facility is completed, the COG Facility must be inspected by a municipal, state, federal, or governmental agency/Authority Having Jurisdiction (an "AHJ"). If no AHJ exists for the COG Facility location, the COG Facility shall be inspected by a qualified licensed electrician or registered professional engineer. The Owner shall provide a copy of the inspection report to the District. The District reserves the right to observe acceptance and operational testing of the COG facilities, including any of the Owner's protective equipment that is essential to the interconnection, relays, circuit breakers, protective devices and related equipment. The testing may include tripping of the Owner's Interconnection breakers by the protective relays to verify all protective set points and relay/breaker trip timing prior to connection to the District's Distribution System. Unless waived, the testing shall be performed prior to interconnection and Parallel Operation of the Owner COG Facility.

The Owner shall provide the District with written notice at least two (2) weeks before the initial energizing and start-up testing of the Owner's COG Facility so that the District may witness the testing of any equipment and protective systems associated with the interconnection.

The District reserves the right to request additional operational testing of the Owner's protective equipment any time a system emergency develops, safety issues arise, or the quality of service to other customers deteriorates, as determined by the District.

Under normal conditions, the District intends to provide advanced notice of all site visits and will coordinate such visits with the Owner. Emergency conditions may require that the District access the COG Facility without advanced notice.

5.3 Operations and Maintenance

The District and other authorities require all COG to operate within agreed expectations, and the District may require execution of an "Operating Envelope Agreement". Failure of COG to operate within agreed expectations can result in significant negative consequences for safety and for grid stability and operations. OPPD will, in many cases, require the COG Owner to submit and maintain specific and detailed inverter, control and protective system settings / programming information to help assure desired and intended operation. Where specified by the District, Owner equipment will be required to be programmed and operate within 'Utility Required Settings' profiles, which are subject to change, and to which the COG Owner will be required to adjust to as needed.

Since significant equipment damage and liability can result from failures of the Owner's protective equipment, the Owner must ensure that all of the COG Facility's protective equipment is operating properly. The Owner is solely responsible for proper operation of the Owner's COG Facilities. The Owner is required to maintain records of operation and maintenance activities, which the District may review at reasonable times.

After the initial testing, the Owner must have a qualified testing firm perform regular periodic maintenance testing of the equipment as specified by the manufacturer. Maintenance records and testing results shall be made available for the District's inspection upon request. The District reserves the right to inspect the records, but has no responsibilities for maintenance, either actual or implied. Owner will not make a change to the COG Facility that might adversely affect District equipment or the Distribution System, without the District's prior written approval.

5.4 Energizing Dead Circuits

The Owner shall not energize de-energized District distribution equipment.

5.5 Islanding

Automatic and manual switching arrangements on the District's Transmission and Distribution System are based on the premise that, upon opening a line or section of the District's electric system, it becomes de-energized.

Under certain conditions with extended parallel operation, it would be possible for a part of the electrical power system to be disconnected from the rest of the District's electrical grid and have the COG continue to operate and provide power to a portion of the District's electrical power system. This condition is called "islanding".

COG equipment that remains energized and interconnected to the isolated portion of the District's electric system or reconnects before District service is restored, creates a hazardous condition for utility employees. For this reason, the District does not allow COG facilities to operate as an 'island' on the District's electric system. The COG Facility must automatically isolate itself from the expected de-energized portion of the District's electric system in the event of a District outage.

5.6 Load Shed

If the COG drops offline, an automatic load shed scheme may be required to shed the Owner's load should this additional load exceed the available capacity of or cause excessive voltage sag on the Distribution System.

5.7 Manual Disconnect

To establish a visually open working clearance, in accordance with the District's safety rules and practices, an approved disconnecting device or switch must be installed on the Owner's side of the Point of Interconnection (as hereinafter defined) near the meter or mutually agreed upon location for all COG classifications. Such device or switch must be capable of directly preventing the COG Facility from energizing the District service wires and must include functionality which, at the District's discretion, allows District employees to operate and lock in place. See Appendix A.18 Disconnect Switch.

5.8 Interconnection Costs

District maintenance and operation procedures are based on a single source serving the District's Distribution System. Interconnection of additional COG or other modifications to the Distribution System will necessitate modification to these procedures. Often, the introduction of COG to the utility system requires capital expenditures for additional utility equipment. The modified procedures and additional utility equipment increase utility costs without providing benefits to other utility customers. In such cases, the expenses for additional District procedures, equipment, maintenance, labor, and other related costs that are over and above the expenses for a non-COG customer shall be paid to the District by the Owner of the COG Facility.

Net metering systems for qualified COG as defined in the Nebraska Revised Statutes Section 70-1012 may be exempt from some interconnection costs.

These Owner-responsible costs are separate from the COG Owner's obligations to purchase, install, and maintain District required interconnection equipment installed at the COG Facility, as well as the cost of professional engineering services and maintenance testing to satisfy District requirements.

The following expense categories are examples of items reimbursable by the Owner to the District:

1. Meter installation, tests, maintenance, parts, and related labor.
2. Meter reading and scheduling, billing.
3. Telemetry installation, tests, maintenance, parts, and related labor.
4. Operating expenses, including communication circuits.
5. Study, analysis, and related expenses.
6. District assistance in securing regional regulatory authority acceptance of the COG Facility.
7. Modifications to the District system including related material and labor.
8. Protective device (District owned) installation/equipment cost and related labor.
9. District costs for COG Facility design review, equipment inspections, and witness testing.
10. Programming costs to incorporate COG data into the District's Energy Management System.

Note: Changes to the District system, or the addition of other COG facilities in the vicinity of the COG Facility, may require modifications to the existing COG Facility interconnection. If such changes are required, the existing COG Facility may be responsible for any such to future costs and/or expenses arising from such modifications.

5.9 COG as part of an Aggregation or Virtual Power Plant (VPP)

When allowed, a COG Owner, under certain circumstances, may wish to have their COG operate as part of an Aggregation or Virtual Power Plant, often with the intent of participating in special retail programs or in wholesale electric markets. Such Aggregations or special retail programs may be offered by the District or by 3rd party 'Aggregators'. Participation and operation of Owner COG under these programs and conditions may result in additional requirements for the COG Owner, including (but not limited to):

1. All COG or Distributed Energy Resource (DER) Aggregators are required to be approved by the District and the District's NERC ISO Region, the Southwest Power Pool (SPP). The Owner is responsible for researching their prospective Aggregator partners or programs to ensure Aggregator eligibility.
2. All COG wishing to participate in such programs must meet all District COG interconnection requirements prior to participation, and existing COG wishing to participate may require upgrades or other modifications to COG facilities or equipment to be eligible to participate. Additional changes to District systems, equipment, or operations may also be required for COG participation, and associated costs may be the responsibility of the COG Owner.
3. Certain large COG types, installations or units with intentions to participate in wholesale electric markets may be required to operate independent of, and not as part of, an Aggregation or VPP. Examples may include large, synchronous generators of 1MW or larger, or other types and sizes of COG. The District will determine eligibility under such conditions. The prospective large COG will

likely require approval by the District and the NERC Region (SPP) to operate as a market participant, so would need to complete additional approval processes.

4. Battery Electric Storage Systems (BESS) COG of certain size and intended to provide certain wholesale market functions will be required (as determined by the District) to have Stage II GFM (Grid Forming) inverters, internal reference voltages, 1.6X / 5 second fault current contribution capability, self-energization/black start capability, immediate response to grid events to support grid stability (virtual inertia) and/or other capabilities as determined by the District and/or the SPP.
5. The District may, on occasion, require Emergency Operations or other operational use of aggregated COG to maintain grid stability or for other operational purposes (including preventive and corrective maintenance needs, storms/outages, equipment failures, load shedding, and for other purposes). District use can include activation, restriction, or override of COG capabilities. The District will endeavor to inform COG customers in advance of such activities but cannot guarantee notification, and will provide no extra compensation for such activities.
6. The District considers customer / COG Owner account information to be confidential, and does not share such information without COG Owner authorization. COG Owners participating as part of an aggregation or similar activities will be required to authorize the District (in writing) to share their account information or delegate other rights to 3rd parties in accordance with District Data Sharing Policies.

Note that the COG Manual governs *sources* of electric power that fall within its requirements, so does not typically refer to Demand Response (DR) or Demand-Side Management (DSM) resources, which may also be Aggregated or made part of a VPP. District requirements for DR or DSM participation in an Aggregation or a VPP reside elsewhere.

6.0 References

Latest version for all Standards, unless otherwise noted.

IEEE Std. C37.90, *Relays and Relay Systems Associated with Electric Power Apparatus*

IEEE Std. C37.95, *Guide for Protective Relaying of Utility-Consumer Interconnection (Latest revision)*

IEEE Std. C84.1, *Electric Power Systems and Equipment – Voltage Ratings (60Hz)*

IEEE Std. 519-1992, *Recommended Practices and Requirements for Harmonic Control in Electric Power Systems*

IEEE Std. 141-1993(Reaffirmed-1999) *Recommended Practice for Electric Power Distribution for Industrial Plants*

UL 1741 – 2010, *UL Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources*

IEEE Std. 1453-2015, IEEE *Recommended Practice for the Analysis of Fluctuating Installations on Power Systems*

IEEE Std. 1547-2003, IEEE *Standard for Interconnecting Distributed Resources with Electric Power Systems*

IEEE Std. 1547-2018, IEEE *Standard for Interconnecting Distributed Resources with Electric Power Systems*

IEEE Std. 1547.1-2005, IEEE *Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems*

IEEE Std. 1547.2-2008, IEEE *Application Guide for IEEE Std. 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems*

IEEE Std. 1547.3-2007, IEEE *Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems*

IEEE 1547.6-2011, IEEE *Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks*

Nebraska State Electrical Act

NFPA 70 National Electrical Code

National Electrical Safety Code, ANSI C2, Published by The Institute of Electrical and Electronics Engineers, Inc.

Appendix A Interconnection Requirements

A.1 General Interconnection Requirements

The Owner's COG Facility shall meet the technical requirements prescribed in this Appendix. The District reserves the right to impose additional requirements as necessary; these additional requirements will be made a part of the Interconnection Agreement.

A.2 Protection of Owner's Equipment

The Owner will be responsible for protecting its generating equipment in such a manner that Distribution System outages, short circuits or other disturbances will not damage the Owner's generating equipment.

A.3 Duration of Parallel Operation

The amount of time a COG will be in Parallel Operation (or "closed transition") with the Distribution System will help determine the requirements for the COG Facility. For the purpose of this Manual, closed transition operation is either momentary or sustained. Momentary closed transition should be used for synchronized closed transition transfer of COG Facility load from one source to another source in order to interconnect the two power systems only during the brief load transfer period. Sustained closed transitions allow the two systems to remain interconnected indefinitely, as long as synchronous operation is maintained.

TYPE OF CLOSED TRANSITION OPERATION	DURATION OF PARALLEL OPERATION	DISTRICT REQUIREMENTS FOR THE COG FACILITY
Momentary*	< 100 milliseconds	Synchronism check on transfers Interconnection disconnect
Sustained	> 100 milliseconds	All District COG interconnection requirements and additional requirements, as determined by the District

*Determination as to whether the COG equipment to be installed is the momentary type above or not shall be made by the District. COG transfer equipment approved as momentary shall be designed, manufactured and listed for use as momentary transfer equipment, and is not designed for sustained parallel operation. COG transfer equipment which meets the momentary requirements above, but which relies on programmable electronic control means, and is capable of being re-programmed or otherwise altered to be capable of sustained parallel operation, shall be considered sustained type. Note momentary type of operation is still closed transition operation, and as such is not approved for applications involving District network service. Automated switchgear capable of closed transition operations via programming or logic changes shall meet the protective requirements and stipulations for sustained interconnections.

The momentary interconnection, or closed transition transfer, can result in a large load suddenly being applied to the COG Facility generation. This step-loading can result in frequency and voltage disturbances that may be unacceptable to the COG Facility load. As a result, the generator should be properly sized and selected to help prevent such power quality problems.

A.4 Drawings

Adequate drawings of the Owner's proposed COG Facility, which include a one line diagram and diagrams of the relay system, may be required for review. The Owner shall also provide relay settings, relay setting calculations and supporting documentation, and relay and control logic. Additional drawings may also be required. Reference COG FAQ page on OPPD.com.

A.5 Point of Interconnection

The interconnection point of the District to any COG Facility is the point at which the District system connects to devices, conductors, or equipment of the COG Facility, as determined by the District (the "Point of

Interconnection"). This point will normally be the "point of common coupling (PCC)" as defined in the IEEE *Standard for Interconnecting Distributed Resources with Electric Power Systems*, IEEE Standard 1547. The service entrance voltage is typically defined by the voltage at this point.

Note: COG facilities may not be able to meet District COG requirements if the COG is interconnected at points in the COG Facility system other than the service entrance. The Owner of the COG Facility must verify the interconnection point with the District during the design stage.

A.6 Power Factor

COG facilities shall provide for their own reactive power needs. Non-exporting COG facilities shall operate the combined generation and load within a power factor range specified in the District's Electric Rate Schedules and Service Regulations. Power factor charges specified in such Rate Schedules will apply to power factors outside of this range.

All exporting COG facilities shall operate at unity power factor unless otherwise specified by the District.

A.7 Voltage Regulation

Voltage regulation is required to be in service whenever the generator is synchronized to the District's electric system. Unless otherwise specified, the Owner will operate its generating equipment within the ranges specified by ANSI C84.1 Table 1, Range A, measured at the Point of Interconnection. On a 120 volt basis, this range is 114-126 volts.

Under-voltage and over-voltage functions are applied to prevent unintended islanding operation. The Owner must provide an automatic method of disconnecting their COG from the District's Distribution System if the voltage cannot be maintained at the POI within the District's limits as stated in the following table 1:

Table 1 Voltage Disturbance Delay & Trip Times

Range		**Clearing Time** [2]	
Percentage	**Voltage[1]**	**Seconds**	**Cycles**
< 50%	< 60	0.16	9.6
50% - 88%	60 - 105.6	2.0	120
88% - 110%	105.6 - 132	Normal Operating Range	
110% - 120%	132 - 144	1.0	60
> 120%	> 144	0.16	9.6

[1] Voltage based on 120V nominal.

[2] Clearing Time includes breaker & relay time.

A.8 System Fault Detection and Protection

These protection requirements are designed and intended to protect the District's Distribution System only.

In view of this objective, the District requires that all protective equipment be able to automatically detect and rapidly isolate faulty equipment. It is also important that all protective equipment be able to limit interruptions only to the faulty equipment or section, so that a minimum number of customers are affected by any outage.

The Owner's protective equipment must be able to independently detect phase and ground faults on the District's Distribution System. All required fault-detection relays must coordinate with the District's devices, as necessary.

The line-protection schemes must be able to distinguish between generation, in-rush, and fault current.

The District's existing relaying schemes may have to be reset, replaced, or augmented with additional relays for proper protection and coordination due to the interconnection of the Owner's new COG Facility. All associated costs to accomplish required modifications/additions will be at Owner's expense.

For communication aided protection schemes, typically high speed protection or Direct Transfer Trip (DTT), the District determines the appropriate communication type to be used on a case-by-case basis.

The leased telephone line or dedicated communication network must have high-voltage protection equipment on the entrance cable so the communication assisted scheme (such as DTT) can operate properly during fault conditions.

Interconnection of any new COG Facility to the District's Distribution System must not degrade the existing protection and control schemes or lower the levels of safety and/or reliability for existing District customers.

Many parts of the District's electric system have provisions for an alternate feed when the normal feeder is out of service. However, due to protection concerns with the existing schemes, there are cases where the District is unable to allow COG to be online while being fed from an alternate source (abnormal operating conditions). For some of these cases, it may be possible to upgrade the existing protective schemes to allow operation of the COG on the alternate feed.

Upon Owner's request, the District can provide the estimated cost of upgrades needed for Owner's COG to stay online while being served from an alternate source. After completion of the required upgrades, which will be at the Owner's expense, the COG Facility may stay online while being transferred to the alternate source. However, if the required upgrades are not completed, the District will require that the COG Facility stay offline while the line section is being served from the alternate source.

1. Direct Transfer Trip

Direct Transfer Trip ("DTT") is required if the District determines that a COG Facility cannot detect and trip for the District's end-of-line faults within an acceptable time frame. DTT is also required when the District determines that the COG Facility is capable of sustaining a section of the Distribution System energized (forming an unintentional island) when separated from the District. Before a new COG Facility may be connected to the District's Distribution System, additional protection and telecommunications systems may be required. When required, these protection and telecommunications systems must be satisfactorily commission tested and in-service prior to Parallel Operation. If the District requires DTT protection, then all required communication circuits and equipment as determined by protection studies, must be provided by the Owner at Owner's expense. The Owner must have a communication line in service for the DTT at least three (3) weeks before the COG Facility is energized.

The number of required DTT's will be determined by the District's protection study. If the District determines that DTT is necessary, the Owner will have to install a DTT to the COG circuit breaker or the interconnection substation circuit breaker from one or all of the following devices:

a. Transmission remote end terminal.

b. High-side circuit breaker/circuit switches on the transmission side of the substation transformer.

c. Distribution feeder circuit breaker.

d. Any distribution line re-closers.

Note: DTT is more likely to be required for non-certified inverter and/or machine based systems than for generation with certified inverter based interfaces. Each COG Facility is reviewed on an individual basis and the requirements will depend on variables influencing protection including: type, size, and location of the generator and the existing protective equipment on the District's electric system.

A.9 Voltage Flicker

The starting of motors and generators may cause inrush currents in excess of normal steady-state operating current. These inrush currents may cause voltage sag (flicker), which can adversely impact the operation of some electrical equipment. The COG is not allowed to produce excessive flicker to adjacent electric customers.

Therefore, the COG Facilities must limit voltage fluctuations on the District's Distribution System at the point of common coupling or Point of Interconnection, within the limits defined by IEEE 1453.

A.10 Frequency

The frequency of the District's Distribution System is 60 Hz nominal and shall be maintained within the limits of 59.3 - 60.5 Hz under normal steady-state operation. Under frequency and over frequency functions are applied to prevent unintended islanding operation. The Owner shall provide an automatic disconnecting means from the District's Distribution System when generation falls outside the values prescribed in the following table 2:

Table 2 Frequency Disturbance Delay & Trip Times

Frequency (Hz)		Clearing Time [2]	
Units < 30kW		**Seconds**	**Cycles**
	< 59.3	0.16	9.6
	59.3 - 60.5	Normal Operating Range	
	> 60.5	0.16	9.6
Units > 30kW		**Seconds**	**Cycles**
	< 57	0.16	9.6
	57 - 59.3	Adjustable Delay [3]	
	59.3 - 60.5	Normal Operating Range	
	> 60.5	0.16	9.6

[2] Clearing Time includes breaker and relay time.

[3] COG Facility breaker must open before the District's breaker recloses.

In the event the Owner's COG fails to disconnect, creating a hazardous condition on the District's electric system, the Owner shall be liable for resulting damage and injuries.

Unless otherwise agreed to in the Interconnection Agreement, reconnection shall be permitted 5 minutes after the utility voltage and frequency return to normal range.

A.11 Under-Frequency Load Shed

A COG Facility's protective devices must coordinate with the District's under frequency load shed ("UFLS") program. The COG Facility's under frequency relays shall be set according to Table 2. The District's engineers will evaluate the UF settings on a case-by-case basis and may provide additional requirements.

A.12 Harmonics

The COG Facility shall not introduce excessive distortion to the sinusoidal voltage or current waveforms that exceed the guideline values for total harmonic distortion published in the latest issue of IEEE Standard 1547, IEEE *Standard for Interconnecting Distributed Resources with Electric Power Systems,* drawn directly from IEEE Standard 519, IEEE *Recommended Practices and Requirements for Harmonic Control in Electric Power Systems.*

The Owner shall cooperate with the District during the analysis of harmonic disturbances and when necessary, provide the District's personnel access to COG system equipment for testing and to obtain information relating to the causes and magnitude of the disturbances. The District will not be responsible for any COG Facility costs associated with the harmonic analysis.

The Owner shall comply with all District recommendations for the installation and operation of corrective equipment required to mitigate any harmonic disturbances generated by the COG Facility. The Owner is responsible for the cost to install and operate this equipment.

The Owner will be required to properly maintain all harmonic correction equipment installed. If the COG produces unacceptable harmonics during parallel operation, or if this equipment fails or no longer provides the level of harmonic correction per IEEE Standard 1547 (Table 3) the District shall disconnect and lock-out the generator from the District's Distribution System until the harmonic correction equipment is repaired and operational.

Table 3 Maximum Harmonic Current Distortion in Percent of Current (I) [1]

Individual Harmonic Order (odd harmonics)[2]	h<11	11<h<17	17<h<23	23<h<35	35<h	Total Demand Distortion
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

[1] IEEE 1547 – I = The greater of the maximum load current integrated demand over 15 or 30 minutes without the COG unit, or the COG rated current capacity (transformed to the PCC when a transformer exists between the COG and the PCC.)

[2] Even harmonics are limited to 25% of the odd harmonic limits shown.
Generally, equipment that is certified as meeting UL 1741 requirements will comply with this guide.

A.13 Synchronizing

The COG Facility shall not be manually synchronized unless authorized by the District. Automatic synchronization shall be supervised by a synch check relay, IEEE Device 25.

The District will have the right to review, and inspect the method of synchronization. Automatic synchronizing settings will not be changed following installation unless mutually agreed to by both parties. The Owner must install proper sensing devices to sense a de-energized circuit to assure that a de-energized circuit of the District is not energized.

The Owner shall be solely responsible for synchronizing their COG with the District's electric system. Table 4 shows the IEEE 1547, Table 5, parameter limits for synchronization to the District's Distribution System.

Table 4 IEEE 1547 Synchronization Parameter Limits for Synchronous Interconnection

Aggregate Rating of COG Facility[1] (kVA)	Frequency Difference (Δ f, Hz)	Voltage Difference (Δ V, %)	Phase Angle Difference (Δ Φ, °)
0 – 500	0.3	10	20
> 500 – 1,500	0.2	5	15
> 1,500 – 10,000	0.1	3	10

[1] Total amount of COG at PCC/POI being synchronized to the District's electrical Distribution System.

A.14 Intertie Transformer

The District may require, at the Owner's expense, a dedicated transformer or transformers to serve the COG Facility. Since transformer connections and configuration can significantly impact the District's Distribution System operation, the District prefers grounded wye to grounded wye transformer connection configuration. The District shall review and if determined to be acceptable, may then approve other transformer configurations upon the request of the Owner.

Six interconnection transformer configurations are used to interconnect COG with the utility system; each has inherent advantages and disadvantages. Regardless of which party owns the interconnection transformer, it is important that the impacts to the Distribution System be considered. The interconnection transformer connection can adversely affect the utility feeder protection scheme, and can have adverse effects on the lightning arresters on the feeder. When the transformer is customer owned, it is important that the connection type be provided to the District so that the impacts to the District's electric system can be considered. Additionally, the use of neutral resistors at the transformer, COG, or both, has impacts that must be considered. Certain configurations may not be acceptable depending on the effect it has to the Distribution System, while others may require modifications to the Distribution System.

Existing delta-delta or ungrounded wye-delta service transformers for COG facilities will usually require reconfiguration of the transformers to wye-wye, installation of grounding transformers, or the installation of utility side voltage unbalance protection equipment. In some cases, upgrading of District transformer insulation levels and lightning arrester ratings to a higher voltage may be required. The COG Facility Owner is responsible for the installation and material costs of such equipment.

A.15 Single-phase Devices

Replacement of single-phase overcurrent devices (line fuses, single-phase automatic circuit re-closers, single-phase line switches) may be required on the District circuit between the District substation and the COG Facility service entrance.

Regardless of whether any single-phase devices are replaced with three-phase devices, the COG Owner is solely responsible for protecting COG equipment from the effects of excessive negative sequence currents, system imbalance effects, or loss of utility phase/utility single-phase conditions. The District is not responsible for damage to Owner equipment due to these or similar effects.

A.16 Protection Equipment

The necessary protective equipment shall be established in the design phase and confirmed prior to start-up of the Owner's COG Facility. The District has the right to require certain protective devices, including relays that the Owner must install. Settings of interconnection protective devices on the Owner's system will be specified by the Owner, but will be reviewed by the District. The District may request changes to the Owner's relay settings.

The Owner shall submit all relay settings, with the engineering basis for the relay settings, to the District for review prior to initial commissioning and prior to any relay setting changes post commissioning. The District reserves the right to have final review on all COG Facility's relay settings. Any aspects of the COG Facility's relay settings that are found to be unsatisfactory by the District shall be redesigned, changed, or otherwise reworked, and then resubmitted to the District for additional review

A.17 Relays and Test Switches

The relaying package shall have a reliable source of power independent from the AC system (DC battery and charger) to assure reliable operation of the protection. Relay trip output contact(s) shall directly energize the trip coil of the COG Facility's breaker or an intermediate auxiliary tripping relay that directly energizes the breaker trip coil.

Relays shall monitor all ungrounded conductors. For example, protection of a three-phase system using single-phase relaying is unacceptable.

All equipment providing relaying functions shall be utility grade devices that meet or exceed ANSI/IEEE Standards for protective relays, i.e., IEEE C37.90, and IEEE C37.90.1. All relays shall be equipped with setting limit ranges at least as wide as specified in IEEE 1547. Setting limit ranges are not to be confused with the actual relay settings required for the proper operation of the installation. At a minimum, all protective systems shall meet the requirements established in IEEE 1547.

The COG Facility's system protective equipment shall be located within the COG Facility whenever possible. The COG Facility's equipment will not be allowed on the District's property. The relays shall be grouped in dedicated panels or cabinets accessible to District personnel. Equipment shall be installed in accordance to manufacturer recommendations, including environmental considerations.

All relays that are not draw-out cased relays shall have appropriate test switches (ABB type FT-1 preferred) to allow testing the operation of the relay without unwiring or disassembling the equipment. The test switch configuration and terminal designation may be reviewed by the District's System Protection group upon the District's request.

A.18 Disconnect Switch

The Owner is required to provide a utility-accessible, lockable, and visible disconnecting device for use by the District as a means of electrically isolating the District's electric system from the COG system and to establish working clearances for maintenance and repair work in accordance with the District's safety rules.

A single disconnect shall be used to isolate all COG at a service, unless approved as an exception by the District prior to OPPD Approval for Construction. The disconnect shall be located next to the meter, unless approved as an exception by the District prior to OPPD Approval for Construction. When installation of the utility disconnect next to the utility meter is not feasible, a printed/etched placard (not handwritten) shall be installed near the meter showing the location of the disconnect. Where installed in the vicinity of similar disconnect switches, the switch shall be clearly labeled with a printed/etched placard as the Interconnection Disconnect Switch to be readily identifiable by District personnel. When energy storage devices are installed, it is typically required for the switch to be installed between the meter and the main service panel to avoid inadvertent energization of protective grounds.

The device shall be a UL-approved or National Electrical Manufacturers Association-approved, manual safety disconnect switch of adequate ampere capacity that meets the following:

- Located at the Point of Interconnection between the COG Facility and the District's Distribution System, or it may be located at the point where the COG system interconnects with the Owner's load. Disconnect switch must be on the AC portion of the system. The DC disconnect will not meet the requirement for the Utility Disconnect.
- Be properly rated for the specific application and installed location.
- Be manually operable and simultaneously open all ungrounded conductors.
- The interrupting rating shall be suitable for the available fault current from either the utility or COG (whichever is greater).
- The switch will be load break type with arc arrestors, and provide a visible means of verifying the switch contacts are in the open position with the switch enclosure open. Switch designs requiring removal of plates, covers or partial disassembly of the switch to provide visual access to the contacts, are not acceptable to the District.
- The switch shall have provisions for padlocking the switch in the open position and shall accommodate a standard District padlock, which may be installed by the District.
- The switch must have provisions for grounding all phase conductors and neutrals (on both sides of contacts) to a proper grounding conductor/electrode within the switch enclosure. The District must be able to close and secure the disconnect door or cover with the ground jumpers in place.

Note: The switch is not required to be fused. Fused switches are not restricted, but removal of the fuses shall not be required to meet the visible means of open switch position described above.

Each interconnect disconnect switch shall be installed as follows:

- The switch enclosure (if conductive) and switch grounding provisions will be grounded in accordance with the NEC and local codes.
- A grounding bar or other grounding point shall be provided within the switch enclosure for termination of District grounding cables. The grounding point shall allow the District grounding cables to be installed with the switch in the open position and the switch door closed and locked.
- The switch shall be installed in a location readily accessible to District personnel (i.e., be erected so as to be a drive-up location). Locked fences or other permanent barriers shall not restrict District access to the switch. Fences may be secured with a chain and series connected District and Owner padlocks, so either the District or the Owner has access without the other present. Where the District has approved switch

locations within dedicated, interior vaults or switch rooms (always with direct exterior access), the District will typically provide door lock hardware (keyed for the District) with interior panic bar for installation within an Owner-provided steel door. The door construction, location, etc. must meet District approval.

Each interconnect disconnect switch is subject to the following conditions:

- NEC service entrance overcurrent protection devices will not be allowed to bypass the District interconnection disconnect switch.
- Is under the sole control of the District, unless the District should release the switch for COG Owner operation. The COG Owner shall not remove any District padlocks or District safety tags. The District will be allowed unrestricted access to the switch and will operate the switch under conditions and at times deemed appropriate by the District.
- Use of the switch is to provide positive separation of the COG source from the District system to effect maintenance or repairs to the District electric system. The District will normally attempt to notify the COG Facility Owner or operator prior to operation of the switch, but the District reserves the right to operate the switch without Owner notification.
    - If the District should not open the interconnection disconnect switch, such act shall not serve to relieve the COG Facility Owner of any liability for injury, death or damage attributable to the negligence of the COG Facility Owner.
- All devices and their locations are subject to approval by the District.
- A molded-case type circuit breaker alone is not sufficient, as it does not allow visual indication of contact position. A switchgear rack mount circuit breaker is not allowed to serve as a visible open.

Also see Section 2.0 Right to Disconnect.

The revenue meter may not serve as the disconnect switch. Revenue meters do not have provisions for protective grounding.

Where Owner COG facilities receive primary metered service from the District, the District's primary service disconnect may be acceptable in lieu of an Owner's interconnect disconnect, at the District's discretion. For purposes of this Manual, primary metered service means single or three phase service taken from the District's electric system at a standard available voltage above 11,000 volts or 4,000 volts provided there is only one transformation involved from the District's transmission voltage (above 60,000 volts) to the service voltage.

A.19 Protection from Automatic Reclosing

The District normally applies automatic reclosing after fault clearing on all overhead distribution lines. The duration of outages due to clearing temporary faults is most frequently in the range of 0.1 - 2.0 seconds, but varies depending on many factors.

The automatic reclosing schemes often assume that the circuit is dead and do not employ any voltage check, phasing, or synchronization schemes. The Owner must insure that his generation is disconnected from the Distribution System prior to automatic reclosing. The District will assume no responsibility for damage to the Owner's equipment due to out-of-phase reclosing.

It is possible to install voltage check schemes at some locations on the District electric system to prevent automatic reclosing. At the discretion of the District, these voltage check schemes may be installed at the Owner's expense. When these schemes are contemplated, both the preferred and the alternate circuits that can supply power will be considered.

A.20 Automatic Throw-Over Service

Automatic throw-over ("ATO") service interconnected with COG creates operational and technical difficulties and will be evaluated by the District on a case-by-case basis.

A.21 Synchronous Generators

Overcurrent devices (circuit breakers) for synchronous generators shall be three-phase devices with electronic or electro-mechanical control. The Owner is solely responsible for properly synchronizing its generator with the Distribution System.

A.22 Induction Generators and Inverter Systems

Induction generation may be connected and brought up to synchronous speed as induction motors if it can be demonstrated that the initial voltage drop measured on the Distribution System at the Point of Interconnection is within the limits stated in the District's Service Regulations and consistent with IEEE 1453. The Owner may be required to install equipment or employ other techniques to bring voltage fluctuations to acceptable levels.

Self-commutated inverters, whether of the utility-interactive type or stand-alone type, shall be used in parallel with the Distribution System only with synchronizing equipment. Line-commutated inverters do not require synchronizing equipment.

A.23 Event Analysis

The Owner shall cooperate with the District in the analysis of disturbances to either the COG Facility or the District's Distribution System by gathering and providing access to any information relating to disturbances, including information from oscillography, protective relay targets and reports, breaker operations, power quality monitors, and sequence of events recorders. Any actions, events, or eyewitness accounts of information relating to a disturbance shall also be made readily available within seventy-two (72) hours of the District's request for the records.

A.24 Requirements for Inverter Based Units 100 kW or Less

Each COG Facility shall have:

a. Accessible, lockable, visible break disconnect switch at the service entrance (near meter for outdoor meters).

b. Over-current protection.

c. Over/under voltage trip.

d. Over/under frequency trip.

e. Manual or automatic synchronizing (may omit if not capable of standalone operation).

Note: Inverter based units that meet the non-islanding requirements of UL 1741 will satisfy requirements A.24 b-e above.

A.25 Requirements for Non-Inverter Based Units 100 kW or Less

These COG Facilities shall have:

a. Accessible, lockable, visible break disconnect switch at the service entrance (near meter for outdoor meters).

b. Over-current protection.

c. Over/under voltage trip.

d. Over/under frequency trip.

e. Manual or automatic synchronizing (may omit if not capable of standalone operation).

A.26 Requirements for Units greater than 100 kW

These COG Facilities shall have:

a. Accessible, lockable, visible break disconnect switch at the service entrance.

b. Over-current protection.

c. Over/under voltage trip.

d. Over/under frequency trip.

e. Manual or automatic synchronizing (may omit if not capable of standalone operation).

f. Ground fault detection and tripping.

g. Reverse power tripping, if not exporting or set to limit export.

Note: Inverter based units that meet the non-islanding requirements of UL 1741 will satisfy requirements A.26 b-g above.

A.27 Metering Requirements

The Owner shall agree to allow the District to install on their premises the equipment necessary to measure loads and other required data.

The Owner may be financially responsible for the installation of District-owned metering equipment.

- The District shall furnish electric revenue meters and instrument transformers including secondary wiring.
- The Owner shall furnish and install at their expense meter sockets, associated cabinets and enclosures for meter equipment, and all conduits and piping between the instrument transformers and meter sockets and provide a suitable metering mounting location.
- Metering is to be installed according to the District's service regulations, metering standards, and/or contracts.

Net Metering is only allowed as provided for by state law or regulation.

A.28 Telemetering

Telemetering may be required depending on the output or the application of the Owner's COG Facility.

All COG requiring telemetry is required to be compatible with IEEE 2030.5, IEEE 1815 (DNP3), SunSpec Modbus, and OpenADR protocols for communications.

Continuous telemetry of power quantities, breaker statuses and alarms are required for:

- All aggregate COG capable of exporting greater than 1 MW to the District's Distribution System at a voltage 15 kV or less.
- Any COG involved in wholesale power transactions, except in situations when operating as part of an approved aggregation and the District determines continuous telemetry is not required.

The Owner shall furnish and install, at their expense, the necessary communication equipment, channel(s) and the necessary District approved telemetering equipment and devices. The District will determine the most appropriate technology.

Typical data points needed are:

- MW (0.01 resolution)
- MVAR (0.01 resolution)
- Volts (13.8 kV)
- Amps (13.8 kV)
- On/Off status at main switch

Additional data points may be required as determined by the District.

The basis for requiring continuous telemetry for power quantities, breaker statuses and alarms are:

- Determination and monitoring of real-time limit thresholds and/or violations.
- Historical tracking of limit thresholds and/or violations.
- Monitoring of the real power flows – real-time and historical.

- Monitoring of reactive power flows - real-time and historical.
- Monitoring of COG on or off line status.
- De-coupling of COG and load for network applications such as state estimation and security analysis.
- Monitoring equipment health and functionality.

A.29 Socket Mounted Adapter Devices

Socket mounted adapter devices may be accepted by OPPD for use on certain COG, including solar installations. Conditions of use, restrictions, and cautions apply:

a. The adapter device must be UL Listed.

b. The adapter device does not take the place of the visible-open disconnect required by OPPD.

c. The adapter device cannot be installed on a ring-style or recessed meter socket.

d. Any terminal block(s) on top of the device prevent the meter socket enclosure lid from being removed. In the event access to the meter socket is required, the customer bears responsibility for removal and reattachment of the terminal block(s) after completion of work.

e. The conduit connected to the terminal block(s) shall be sufficiently flexible to be moved out of the way in situations where the meter socket itself would need to be accessed.

f. The adapter device is the customer's property.

g. Whole-house Surge Guard devices located on the meter cannot be used in conjunction with the adapter device. Panel mounted Surge Guard is available should the customer wish to continue enrollment.

Appendix B Testing Guidelines and Inspections

B.1 Testing Requirements

All COG protective relays must be tested and calibrated per manufacturer recommendations and industry standards. The District reserves the right to trip the intertie interrupting device to verify on demand the calibration of all protective equipment including relays, interrupting devices, etc., at the Point of Interconnection.

B.1.1 Testing Parameters

a. The following data will be collected for **certified** equipment:

- Device ratings (kW, kV, Volts, amps, etc.).
- Maximum available fault current in amps.
- In-rush current in amps.
- Trip points, if factory set (trip value and timing).
- Trip point and timing ranges for adjustable settings.
- Nominal power factor or range if adjustable.
- If the equipment is certified as non-exporting and the method used (reverse power or under power).
- If the equipment is certified as non-islanding.

b. The following data will be collected for non-certified equipment:

- Test results for non-certified equipment must be submitted to District for supplemental review; the manufacturer or a laboratory acceptable to District may perform tests; and
- Approval by District for equipment used in a particular COG Facility does not guarantee District approval for use in other COG facilities.

B.1.2 Commissioning Tests

The District and/or the Owner shall notify the other in advance of performing tests of its interconnection facilities and shall notify each other of any modifications to its facilities that are found to be necessary as a result of such testing.

Commissioning tests shall include visual inspections of the interconnection equipment and protective settings to confirm compliance with the interconnection requirements. District personnel have the right to witness the following commissioning tests which may include, but are not limited to:

- Equipment Commissioning Tests (Conducted prior to energizing the system)
    - Instrument Transformer Tests – Verify proper wiring, polarity, CT/PT ratios, and proper operation of the protection and measuring circuits. CTs shall be visually inspected to ensure that all grounding and shorting connections have been removed where required.
    - Verifying Final Protective Relay Function Settings and Testing – Confirm and document all devices are set to the final review settings. All protective relays shall be calibrated and tested to ensure the correct operation of the protective element. Documentation of all relay calibration tests and settings shall be furnished to the District.
    - Trip Test/Checks – Protective relay control circuits shall be tested to ensure they correctly activate associated interrupting device(s).
- Direct Transfer Trip / Anti-Islanding Function (if applicable).
- Inability to Energize Dead Line.
- Time Delay on Restart After District Source is Stable.
- District System Fault Detection (if used).
- Synchronizing Controls (if applicable).
- Grounding shall be verified to ensure that it complies with this guideline, the NESC, and the NEC.
- Auxiliary Equipment Energization (600 V and below).
- Control System Tests – Remote control, SCADA, and remote monitoring tests.
- Initial Energization – Verify correct CT/PT secondary values and inputs to protective devices and metering, phase tests, and synchronizing test.

- Post Energization Tests – On-line commissioning test including an anti-islanding test will proceed once the Owner has completed pre-testing and the results have been reviewed by the District.

For inverter based COG inspection checklist, see Appendix C - Inverter Based COG Inspection Checklist

B.1.3 Final System Sign Off

The COG Owner must submit the commissioning test results to the District for review before any COG Facility is energized from the District's Distribution System. The District will provide a permission-to-operate letter to the COG Facility owner directly interconnected to the District's Distribution System contingent upon successfully completing all commissioning tests.

Appendix C Inverter Based COG Inspection Checklist

Customer Name: ____________________ Contractor Name: ____________________

Customer Address: ____________________ Meter Number: ____________________

Net Metering (Y/N): ________

1. General

- ☐ System appears to meet all design criteria and interconnection requirements specified in the OPPD COG Manual.
- ☐ Installation is consistent with design drawings approved per COG Application process.
- ☐ Installed equipment is UL listed.
- ☐ Major components are listed for voltage/current ratings of installation per design drawings/application.
- ☐ Permanent labels have been installed on required components to indicate presence of alternate generation.
- ☐ Installed equipment does not appear to have been modified in such a way that would invalidate UL listing.

Notes/Comments____

2. Interconnection

- ☐ AC disconnect has been installed between OPPD meter and inverter, within line-of-sight from meter.
- ☐ AC disconnect appears appropriately sized for its application.
- ☐ If AC disconnect cannot be physically located within line-of-sight, a means of indicating its presence and specific details on its location have been provided (e.g., signage, map, etc.).
- ☐ Meter socket is of an approved type per Meter Specification Manual.

Notes/Comments____

3. System Performance

- ☐ Net metering (if installed) is functioning correctly.
- ☐ System de-energizes when AC disconnect is opened.
- ☐ System does not re-energize for 300 seconds after AC disconnect is closed.

Notes/Comments____