Ameren Illinois Distributed Energy Resources Interconnection Policy Public Facing Guide

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Revision 2

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1. Definitions

Ameren Service Manual (ASM): Ameren's reference guide that facilitates the planning and installation of electrical equipment on customer systems operated at or below 1000 volts in a safe and reliable manner. This guide is applicable in both Ameren Illinois and Ameren Missouri territories. Section 1500 of the ASM specifically covers DER interconnection requirements for Ameren Illinois customers.

Behind the Meter (BTM) DER: distributed generation designed to operate in parallel with the Ameren Illinois EPS that is located at the premise of a load customer and shares a revenue meter with other loads.

Collectively Owned Generation Facilities (COGF): A COGF is an electric generating facility, typically using solar panels, that is:

1. Installed on-site at a multi-unit residential or commercial property (e.g., on the roof, over a parking lot, or on unoccupied land).
2. Owned by the property owner or a single entity representing the collective ownership of the building's occupants.
3. Interconnected to the utility's distribution system, either directly or through the existing service transformer.
4. Equipped with its own Ameren Illinois revenue meter.
   4.1. Cannot be installed behind an Ameren Illinois revenue meter intended to serve load.
5. Designed to offset the electrical consumption of multiple tenants or units within the property.
   5.1. COGF cannot be used to offset load behind meters that are permanently associated with the landlord/COGF system owner (i.e. house meters).
   5.2. COGF can be used to offset load behind meters temporarily under the system owner's name, such as cases where meters for unoccupied units are in the landlord's name.
6. Managed through Ameren Illinois' Renewables Portal, allowing the owner/property manager to allocate the credits from the generated electricity to individual units' electric service bills without requiring special wiring or submeters.
7. Providing financial credits directly to the participating tenants' monthly electric service bills based on their allocated share of the generation.

Distributed Energy Resource (DER): a source of electric power that is not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with interconnection requirements is part of a DER.

Distributed Generation (DG): devices that are connected to the distribution or subtransmission system that create electricity at or near the point at which the energy is used. Solar is commonly connected to the electric system as distributed generation.

Distribution Automation (DA): the use of modern technology on the EPS to facilitate the automated location of electrical faults and/or the automated restoration of customers experiencing an electric outage with automated switching.

Distribution System: in this document, distribution systems are electrical circuits with a nominal line-to-line voltage between 4kV and 15kV

Electric Power System (EPS): facilities that deliver electric power to a load.

Energy Storage System (ESS): a mechanical, electrical, or electrochemical means to store and release electrical energy, and its associated electrical inversion device and control functions. Batteries are commonly used as energy storage systems in DER systems.

Export Capacity: the maximum amount of power that a DER facility can export to the Ameren Illinois EPS. Export capacity is most often referred to with DER systems that limit their export of power to less than the nameplate capacity.

IEEE: the Institute of Electrical and Electronics Engineers. This organization publishes standards relevant to DER interconnection including but not limited to IEEE 1547 and IEEE P2800, standards that govern interconnection to the distribution system and subtransmission system, respectively.

Interconnection: the result of adding DER to the Ameren Illinois EPS.

Interconnection Agreement (IA): a contract agreed to by Ameren Illinois and the DER customer after the completion of interconnection studies. This agreement contains details about the interconnection including but not limited to DER operational requirements, required system modifications to facilitate interconnection, and associated costs for those modifications.

Interconnection Facilities: facilities constructed specifically to safely and reliably interconnect DER to the Ameren Illinois EPS. This equipment is typically at or near the POI and includes a tap line to reach the desired POI, DER metering equipment, and Ameren Illinois-owned protective devices dedicated to the DER.

Interconnection Study: the review that Ameren Illinois completes in response to a proposed customer interconnection. In this document, this term may refer to expedited reviews, supplemental reviews, feasibility studies, system impact studies, facilities studies, or any combination of these.

Nameplate Capacity: the maximum rated output of a DER system under specific conditions designated by the manufacturer and usually indicated on a nameplate physically attached to the power production equipment.

National Electrical Code (NEC): the code document that governs building and premise wiring.

National Electric Safety Code (NESC): the code document that governs electric and communication utilities.

Permission to Operate (PTO): official permission granted by Ameren Illinois to operate DER in parallel of the Ameren Illinois EPS after successfully completing a witness test.

Point of Interconnection (POI): the point at which a local EPS connects to the Ameren Illinois EPS. This is also referred to at the point of common coupling (PCC).

Remotely Located Generation (RLG): distributed generation located remotely from the load/market they're intended to serve, such as independent power producers and community solar facilities.

Subtransmission System: in this document, subtransmission systems are electrical circuits with a nominal line-to-line voltage of 34.5kV or 69kV

System Modifications: required addition or modification to the existing EPS to accommodate the interconnection of the DER facility.

Witness Test: a set of commissioning tests for DER systems that are conducted by the Ameren Illinois to ensure the systems meet certain operational criteria prior to granting PTO. These tests ensure the safety and reliability of the Ameren Illinois EPS.

2. Introduction

2.1. Purpose and Scope

The Ameren Illinois Distributed Energy Resources Interconnection Policy Public Facing Guide is designed to familiarize Ameren Illinois customers, distributed energy resource (DER) developers, and installers with DER interconnection on the Ameren Illinois electric power system (EPS). Ameren Illinois' interconnection requirements are designed to facilitate customer-sited DER installations while simultaneously ensuring the delivery of safe and reliable power to all customers. Topics covered in this document include the interconnection application process, system requirements that must be upheld, construction and operational requirements of customer DER systems, the interconnection study process and an overview of typical EPS modifications required for interconnection projects, and the testing and commissioning of new DER sites. This document is meant to supplement, not replace, other pertinent requirements explained further in the DER Customer Responsibilities section below. More information around interconnection with Ameren Illinois can be found at the Ameren Illinois Renewable Resource Center.

2.2. DER Customer Responsibilities

In Illinois, the interconnection of DER to the distribution system is governed by Illinois Administrative Code Title 83, Part 466 "Electric Interconnection of Distributed Energy Resources Facilities" and Part 467 "Electric Interconnection of Large Distributed Energy Resources Facilities" (abbreviated to as Part 466/467 in this document). Both the electric distribution companies (EDCs) and interconnection customers in Illinois are bound to these rules. Additionally, DER customers must adhere to the terms and conditions defined in the Interconnection Agreement (IA). DER facilities found to be out of compliance with Part 466/467 and/or the IA may be subject to disconnection. DER facilities that operate at a voltage of less than 1000 V are also subject to the requirements defined in the Ameren Service Manual (ASM). Specifically, section 1500 of the ASM covers DER related topics, but all sections of the ASM may contain requirements due to the similar nature of DER interconnection to other types of electric service work.

Customer DER equipment and facilities must be designed, constructed, and maintained by the customer according to Part 466/467, IEEE Standard 1547, IEEE Standard P2800, the National Electrical Code (NEC), the National Electric Safety Code (NESC), the ASM, the requirements defined in this document, and any other applicable laws or regulations that may apply based on the site-specific properties of a DER interconnection. Ameren Illinois' interconnection requirements are primarily designed to protect Ameren Illinois employees and facilities and mitigate negative reliability and power quality impacts of DER interconnection to other Ameren Illinois customers; protection of a customer owned DER system is the sole responsibility of the DER customer.

3. DER Interconnection Process

3.1. Illinois Interconnection Incentives

There are multiple existing and potential revenue streams for customers that drive growth of DERs across Ameren Illinois service territory. The primary revenue stream for customers installing distributed generation are the renewable energy credits ("RECs") provided through the Illinois Power Agency's ("IPA") Long-Term Renewable Resource Procurement Plan ("LTRRPP"). Monetization of generation output following construction is primarily provided through retail tariffs.

Residential and non-residential customers who own or operate a renewably fueled generator of 5,000 kW capacity or less and located at their point of electric service may qualify for net metering. Net metering customers can apply revenues from renewable generation towards supply costs from Ameren Illinois. Additionally, smaller Ameren Illinois customers (customers with a peak yearly demand of less than 150 kW) may carry excess generation credits into future billing periods in accordance with the tariff governing net metering.

DER customers can also apply to become a Qualifying Facility (QF) and receive compensation for all of a qualifying generator's output based on Midwest wholesale electric market prices. QFs are small-scale generators of commercial energy that meet Federal Energy Regulatory Commission's (FERC) requirements for ownership, size, and efficiency to qualify as non-utility generation units, and are limited to 20 MW. Because they do not directly serve utility customers, QFs are exempt from many federal and state regulatory requirements, including federal and state rate regulation and oversight by the Securities and Exchange Commission. QFs are not exempt from environmental regulations.

3.2. Applying for Interconnection:

All Interconnection application forms can be located here at the Ameren Illinois Renewables web page. Additionally, all applications can be submitted electronically via PowerClerk, Ameren Illinois' application portal. Interconnection in Illinois is broken down into several different levels depending on the size of the proposed DER system and the type of EPS used for interconnection. There is also a pre-application process that can be used to gather information about the existing facilities at a given proposed POI. While the pre-application process is valid for all levels of interconnection, it is not required, and is often bypassed for smaller behind the meter (BTM) facilities that do not have the flexibility of choosing their POI. The application levels and fees as defined in Part 466/467 are summarized in Table 1 below for reference.

Table 1. Application Level Criteria and Fees

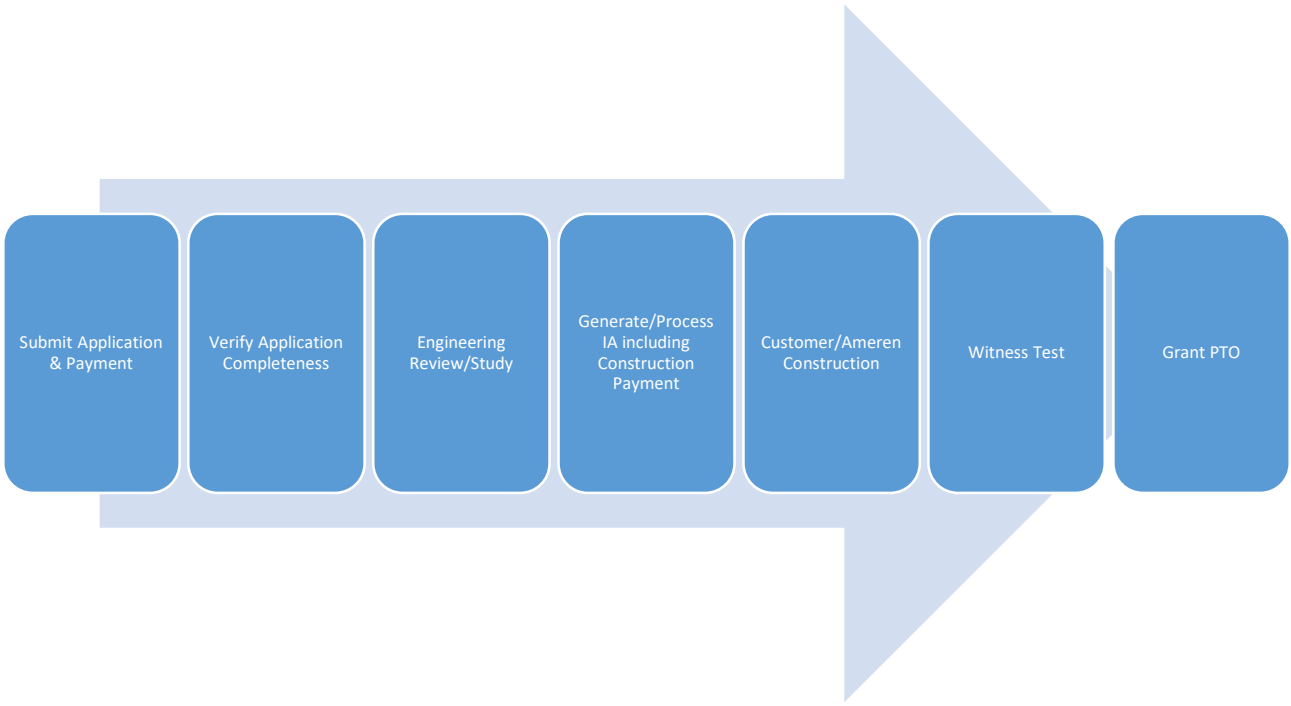
Application Level	System Requirements	Fee to Apply
Pre-Application	No system requirements, but is typically designed for projects larger than Level 1. An alternative to the pre-application process would be to utilize Ameren Illinois' Hosting Capacity Maps, which are available to the public at no cost. They can be found here.	$300
Level 1	DER export capacity of 25 kW or less, nameplate capacity of 50 kW or less (likely connected behind the meter at a residence or small business)	$50
Level 2	DER is connected to a distribution or subtransmission line (69 kV or less) and has a nameplate capacity up to 5 MW depending on interconnection voltage	$100 plus $1 per kVA nameplate capacity*
Level 3	DER connected to a networked system and does not export power, nameplate capacity of 50 kW or less OR connected to radial distribution with nameplate under 10 MVA	$500 plus $2 per kVA nameplate capacity
Level 4	DER is 10 MVA or less and does not qualify for one of the lower levels of application	$1,000 plus $2.00 per kVA nameplate capacity (part of this is refundable)
Part 467 Interconnection	DER is larger than 10 MVA	$5,000 plus $10,000 study fee subject to true-up

*Level 2 applications that fail the expedited review are typically given the opportunity to continue with a supplemental Level 2 review that requires a $1,500 review fee

3.3. Interconnection Process Overview

The interconnection process begins when a customer or developer submits an interconnection application. The application must include information about the DER facility including the fuel source, nameplate capacity, export capacity, and equipment being used. Level 2 and above interconnections must also include a site plan and electrical diagram (one-line) in the application. Additional one-line and site plan requirements for RLG projects and BTM projects 200kW and above can be found on the Ameren Illinois Renewables Website: BTM 200kW and Above Requirements; RLG Requirements. When an applicant is not currently an Ameren Illinois customer at the proposed site, the applicant shall provide, at the time of the interconnection request, proof of the applicant's legal right to control the site, evidenced by the applicant's name on a property tax bill, deed, lease agreement, option agreement, or other legally binding contract. Applications are reviewed based on the processes and procedures defined in Part 466/467 to ensure the delivery of safe and reliable power to all customers and Ameren's co-workers. If the interconnection study identifies system modifications to the Ameren Illinois EPS that are required for interconnection to proceed, the applicant will be provided with an estimated cost for modifications. Ameren Illinois will then generate an Interconnection Agreement (IA) that includes any necessary system modifications and DER customer charges. The DER customer constructs their facilities, Ameren Illinois constructs any required facilities, and when both parties are ready a witness test is

scheduled. After the DER facility successfully passes the witness testing, permission to operate (PTO) is granted to the DER customer. The flow chart on the next page gives an illustration of the interconnection process.



3.4. Energy Storage Systems

Applications for energy storage system (ESS) interconnections follow the same process as other DER interconnections. An "ESS Supplemental Form" must be completed for such applications and can be accessed via PowerClerk by indicating in an application that ESS interconnection is desired. For ESS-only applications, the application level and associated fees is based on the AC nameplate size of the inverter following the same guidelines from Table 1 above. Each ESS application will fall under one of the six categories of ESS charging and export listed in Table 2 below.

Table 2. ESS Charging and Export Configurations

Description	Export Compensation	Applicable Tariff	Hardware And Controls Required
Type 1-NEx: ESS can only charge from appropriate source , no ESS export allowed	All export netted through NM or gross output compensated thru QF	Rider NM or QF	Power Control System (PCS)* (No Exchange Mode)
Type 1-Ex: ESS can only charge from appropriate source, ESS export allowed	All export netted through NM or gross output compensated thru QF	Rider NM or QF	PCS (Export Only Mode) or DC Coupled with 2 Quadrant Inverter (Generation Only)
Type 2-NEx: ESS can charge from appropriate source and Grid, no ESS export allowed	All export netted through NM or gross output compensated thru QF	Rider NM or QF	PCS (Import Only Mode)
Type 2-Ex: ESS can charge from appropriate source and Grid, ESS export allowed	Only energy-sourced kWHr receive export netting or gross output compensated thru QF	Rider NM or QF	Separate energy-source and ESS meters
Type 3-NEx: ESS can only charge from Grid, no ESS export allowed	NA	Standard rates	PCS (Import Only Mode) or Relaying
Type 3-Ex: ESS can only charge from Grid, ESS exports allowed	MISO or NA	Standard rates	No Requirement

*** Power Control System (PCS)**: Depending on the 'description,' PCS equipment can be certified by UL 1741 for the following modes:

- *Export Only Mode* – ESS may export to grid during discharging, but shall not import from grid for charging purposes
- *Import Only Mode* – ESS may import from grid during charging, but shall not export to the grid for discharging purposes
- *Unrestricted Mode* – ESS may import from grid during charging and may export to grid for discharging purposes
- *NO Exchange Mode* – ESS shall not exchange power with grid for charging or discharging purposes

3.5. Interconnection Queue Process

DER interconnection applications are studied following a queue process to ensure fairness and consistency when considering system impacts, balancing a holistic view of the electric distribution system with expedience. Level 1 systems are studied on a first-in, first-out basis and are not tracked via the interconnection queue. Level 2 and larger applications are queued based on the time the application is submitted and the electrical system that will serve the proposed interconnection. Consideration must be given to the primary and alternate subtransmission sources when determining common system components and shared impacts between two or more DER systems. This in mind, the queuing area may be limited to a distribution substation or include multiple bulk substations depending on the configuration of the EPS serving the proposed POI.

4. System Requirements and Limits

Ameren Illinois' interconnection study process is designed to facilitate the interconnection of customer owned DER while maintaining the safety, reliability, and affordability of the EPS. The following criteria and considerations determine if a proposed interconnection can occur without system modifications, or the scope of any required system modifications and associated customer charges.

4.1. Thermal Loading Limits: DER interconnections must not cause Ameren Illinois' current carrying devices (e.g. conductors, transformers, switches, reclosers, etc.) to exceed 90 percent of their thermal ratings.

4.2. Ameren Illinois' Steady State Voltage Requirements: Ameren Illinois is required by the ICC to maintain a delivery service voltage for residential customers of 120 volts ± 7 volts (120V base). For non-residential customers, Ameren Illinois must maintain a delivery service voltage within 10% of the nominal service voltage. DER interconnections onto the Ameren Illinois distribution system must not cause steady state voltage to deviate from these requirements. For more information on Ameren Illinois's service voltage regulations, please see ICC Administrative Code Title 83: Chapter 1 Section 410.300 Voltage Regulation.

4.3. Distribution (15kV and below) Frequent Voltage Variation (FVV) Limits: Ameren Illinois requires that the maximum voltage change at any point on the distribution system due to the DER tripping off-line must be less than 3% of the nominal voltage. Additionally, the maximum voltage change due to the DER instantly ceasing to generate at any voltage regulation device must be less than 2% of the nominal voltage to prevent excessive operations of the device.

4.4. Subtransmission Voltage Variation Limits: These limits apply to subtransmission interconnection studies.

4.4.1. Frequent Voltage Variation: Voltage variation on the EPS caused by the intermittent output of solar- and wind-based DER shall not exceed 1.5% after the DER output has dropped from 100% of the AC megawatt export limit to 50%. This is to limit the excessive operation of voltage regulating equipment, resulting in loss of life and premature failure.

4.4.2. Infrequent Voltage Variation: Voltage variation on the EPS caused by switching, unplanned tripping, or maintenance of a DER shall be limited to 10%.

4.5. Stability Analysis Requirements: Grid stability requirements apply to both subtransmission and distribution interconnection studies. Grid stability and power quality are essential to maintaining a reliable electric power system that is operating with parallel inverter-based generation sources. A weighted short-circuit ratio (WSCR) metric is applied when evaluating an interconnection application to determine if the application is proposing to connect to a point on the grid where stability may be limited. Ameren Illinois is working toward developing the capability and expertise to perform an electromagnetic transient (EMT) analysis for such project(s), which would provide further insight into grid stability, based on the individual project and its proposed interconnection placement. While that EMT study capability is being developed, the WSCR screen serves as the primary grid stability analysis used in

interconnection studies. A WSCR metric at the POI of the DER must be greater than 10 during both normal and contingency system conditions.

4.6. Single-Phase DER Interconnection Limits: Ameren Illinois developed several limits regarding single phase DER systems based on the Admin Code Part 466 screen limiting imbalance on a single phase 120/240 V service (specifically, this limit is presented in Parts 466.90(a)(4) and 466.100(a)(8)). These limits are designed to maintain system phase balancing while allowing smaller applications, which often do not have three-phase equipment available, to proceed with interconnection. Installations behind a three-phase meter should be balanced, three-phase generators whenever possible to preserve phase balancing. In all cases, single phase DER interconnections are limited to 100kVA to prevent phase imbalance. Additional limits around single phase DER interconnections may apply depending on the existing service voltage for BTM DER installations.

4.7. Supervisory Control and Data Acquisition (SCADA) Requirements

4.7.1. For Behind the Meter installations 200 kW AC and larger, a SCADA-capable meter shall be installed to allow Ameren to monitor the output of the generation. Additionally, ESS metering is required for any ESS capable of exporting 200kW or greater, or any BTM ESS sited at a DS-3 customer or larger (a DS-3 customer has a peak demand greater than or equal to 150 kW in two of the 12 monthly billing periods but less than 1,000 kW maximum demand in 11 of the 12 periods during the prior calendar year). This meter will connect to Ameren approved, customer-installed PT's and CT's. The assembled meter cabinet will be provided to the customer to be mounted and connected to their instruments. The meter will be installed and programmed during the witness test by Ameren personnel.

4.7.2. In some cases, BTM DER installations with an export capacity of 1MW or greater (including contribution from both generation and energy storage) will require a SCADA-capable electronic recloser upstream of the point of delivery when engineering judgement deems the device necessary. This protective device is intended to prevent EPS issues when a customer installs large generation or energy storage such that the BTM DER could impact the system in a similar manner to remotely located generation (RLG) DER.

4.7.3. For installations interconnecting at distribution voltage or greater, a SCADA-capable recloser shall be installed at the POI. This device will be owned and installed by Ameren to monitor the output of the generation and disconnect the generation in the event of an emergency.

4.7.4. For any voltage regulation device upstream of a generator that can experience reverse power flow due to the generator, a SCADA communications package will be required to monitor system voltage, current, active and reactive power and ensure proper regulator operation. This will be installed by Ameren and paid for by the generation owner that creates the reverse power flow condition.

4.8. Direct Transfer Trip (DTT)

Direct Transfer Trip is a high-speed communication/relay function usually initiated by a protective relay device upstream of generation. It is intended to rapidly remove generation for EPS faults so

that it does not aggravate the situation or cause any unexpected impacts (overvoltage, islanding, etc.) to Ameren Illinois customers. DTT is also required to properly isolate the generation if the circuit or line has an automated Distribution Automation scheme, in order to ensure proper operation of the automatic transferring of load to alternative sources.

4.8.1. For 34.5kV and 69kV connections, Direct Transfer Trip (DTT) to Ameren Illinois owned equipment may be required. The requirement of DTT applies to normal and alternate sources and is determined by the following conditions:

- Generation has ability to cause reverse power flow onto the transmission system
- An unintentional islanding condition could be formed with a mix of synchronous, asynchronous, and/or inverter-based generation
- Aggregate generation capacity exceeds two-thirds of the minimum line loading
- Generation facility capacity is greater than 10 MVA

Ameren Illinois typically requires radio or cellular as the communications path for direct transfer trip schemes. Fiber optic cabling may be required in some circumstances.

4.8.2. For 15kV and below three-phase primary interconnections, DTT shall be required for DER that is able to reverse power flow at the substation protective device. This will be facilitated by enabling communication between the protective device at the POI and the other protective devices on the circuit upstream of the POI.

4.9. 59N Schemes and System Protection Requirements

Ground fault over voltages can occur on the high side of delta connected substation transformers when the transformer, subtransmission line, or transmission source protective devices operate for ground faults and significant generation exists on the low side system. If the aggregate generation could exceed 2/3 the minimum load of the subtransmission or transmission system that could become islanded, a 59N scheme may be required. The voltage ratings of surge arresters on the high side of delta connected Ameren IL substation transformers will be evaluated for suitability during line to ground faults as well.

Ameren IL subtransmission line terminals and protective devices will be evaluated for synchronization check or dead line reclosing provisions and the need for directional relaying if the aggregate generation on a line can exceed 67% of the minimum load.

Subtransmission busses that were designed for a radial system where added generation can exceed the minimum loading will be evaluated and may require the addition of protective and/or lockout relays.

4.10. Subtransmission N-1 Contingencies

Mitigation measures necessary to comply with these requirements shall be at the Customer's expense. 34kV and 69kV systems must be compliant with all interconnection requirements at both normal and N-1 contingency system configurations.

5. Customer DER Project Requirements

5.1. The customer shall install and maintain ownership of all required interconnection facilities on the customer side of the POI. For RLG facilities, Ameren Illinois will install and maintain ownership of all required interconnection facilities on the utility side of the POI and the POI will mark the point of change of ownership of facilities. BTM facilities will often have customer owned equipment and conductors on the utility side of the POI.

5.2. All inverter-based generation shall utilize inverters that are IEEE 1547 and UL 1741 SA compliant. All inverter-based DER must be capable of and set to disconnect for a loss of utility phase within two seconds. Inverter-based DER must also wait 300 seconds after the restoration of full grid voltage to begin to reconnect, and reconnect at a rate of no greater than 2% of nameplate capacity per second or less. For inverters incapable of a smooth, linear ramp function, a step function may be used such that the average increase in generation is less than or equal to 2% per second, provided that each step is no more than 20% of the DER's nameplate capacity spread across equal intervals over the same period of time (no less than 50 seconds). Additionally, generation utilizing a smart inverter must meet the Ameren Illinois Smart Inverter Specifications to be eligible to receive a Distributed Generation Rebate. The rebate application can be found here. Ameren reserves the right to verify these settings to ensure compliance.

5.3. A DER project owner may choose to "derate" inverters if inverters of the desired nameplate capacity are unavailable for any reason. The following procedure shall be followed when a project uses derated inverters:

5.3.1. The manufacturer must issue the device a new nameplate which reflects its new restricted maximum operating capability, or the inverter must be labeled with a permanent placard indicating the manufacturer has derated the inverter in such a way that the DG owner cannot reverse the changes. Placards shall be phenolic and when secured to the outer cover of the electrical enclosure shall be adhered using permanent adhesive. When the surface area of the electrical enclosure does not permit attachment, the placard is permitted to be adhered to a wall or immediately adjacent surface. Placards shall not overlay critical equipment information such as ON / OFF designations or equipment ratings and shall not overhang the surface of the equipment to which they are attached.

5.3.2. The new maximum power output rating must be implemented in such a way that only the manufacturer or their authorized representative (ex: maintenance technician, not the customer or developer) can modify it. This is typically accomplished by requiring a specific, manufacturer-maintained passcode which is not made available to the customer.

5.3.3. The interconnection application must reflect or be amended to reflect the new maximum output capability.

5.3.4. The manufacturer must provide an attestation letter indicating that all the above requirements are met. The attestation letter shall be uploaded to PowerClerk.

5.4. A DER project owner may choose to implement a limited export DER system to reduce the potential impacts to the distribution system. These systems are most suitable for load customers installing DER to offset their load, using the export limit to reduce DER system output during times of lower loading. IL Admin Code Part 466.75 lists applicable methods to

implement export controls on DER projects in the state of Illinois. Ameren IL has the following requirements for projects implementing an export control system:

5.4.1. The submitted one-line will need to show the export limiting equipment, including any control wiring used to provide power production / export data to the controller and any communications wiring use to control the system inverters or other protective devices such as relays.

5.4.2. The export limit value needs to be clearly indicated on the one-line diagram.

5.4.3. The developer needs to provide us with a brief narrative of the logic used by the controller to ensure that the site will adhere to the agreed upon export level. This narrative needs to include a description of how the system will ensure that the export limit is enforced if the controller fails or there is a communication failure between controller and the managed end points. The preferred approach is that this is included as a table or descriptive text included with the one-line drawing package.

5.4.4. The Illinois Administrative Code Part 466.75(c) describes several different approaches to the design of an export limiting control system, and AIC will typically accept any of these design approaches. AIC will review the one-line and proposed controller operational logic to ensure that we believe the system is robust enough to function reliably.

5.4.5. AIC will validate the operation of the export limiting system during the DER witness test. Depending on the design of the system and environmental conditions on the day of the test, the customer may be required to shed load as part of the testing.

5.5. All Customer generation connections should comply with the recommended practices outlined in latest version of IEEE Standards 519 and 1453 to limit harmonic voltage and current waveform distortion. Inverters shall be rated as IEEE 1547 compliant and UL 1741 safety compliant. Adequate voltage control shall be provided by all Customers to minimize voltage deviations on the Ameren IL electric system caused by changing generation output. Generation output may be subject to reduction below maximum rated output if power factor, VAR control, or other control mode is required. Inverter based resources > 10 MW are required to meet minimum reactive capability at all active power levels including zero MW. The POI to the electric distribution system shall be the point at which all appropriate voltage, current, and harmonic thresholds apply, including settings and thresholds required for a Smart Inverter Rebate as defined in the Smart Inverter Specifications included as a supplement to Rider CGR.

5.6. A generator disconnect switch must be installed by the customer that can safely isolate all parallel generation or energy storage (DG or ESS) from the distribution. This switch must be the first device on the generation side of the POI and must comply with the guidance provided in the Generation Customer Checklist provided during the application process. A separate disconnect switch for an ESS may be required for systems that incorporate both DG and ESS. This switch must be lockable, readily accessible to utility, gang operated (if three-phase), and have a visible indicator of the switch's position. If the voltage at the POI is greater than 1000V, the switch must also have a visible air gap when in the open position. This switch is required per the 2020 NEC (sections 480.7(B), 690.12(C), 694.22(C)(1), and 706.15(A)) to allow utility personnel, the customer, or emergency first responders to isolate DER facilities for maintenance, reliability, or safety concerns. In cases where the generator disconnect switch is locked closed or locked behind a gate, a lock box will be provided by Ameren Illinois and installed by the customer at an accessible location to Ameren Illinois personnel. The lock box

will contain a key to access and operate the generator disconnect switch and will be locked closed with an Ameren Illinois lock.

For buildings with roof mounted panels, the system must include a RAPID SHUTDOWN DEVICE (RSD). For string inverters, this is typically a rotary switch that is behind the inverter weather shield or a rotary switch that is mounted adjacent. Microgrid systems (systems that include a Microgrid Interconnect Device (MID) and can form an intentional island) may have an RSD that controls the PV, ESS, and Standby Generator rapid shutdown functions.

5.7. Ameren Illinois requires a fault isolating device at the generation connection to ensure the reliability and integrity of the EPS. For RLG, the customer is required to install a protective device at the tap or within 500 feet of the tap. The customer's main protective device shall be owned by the customer, and the customer is responsible for maintenance and replacement of the protective device. For RLG interconnections, the protective device is **required** to be an electronically controlled recloser or breaker. When installed, this device should be programmed to sense voltage imbalance and loss of phase to disconnect the DER accordingly. The protective device must be capable of detecting faults on the customer's system and on the Ameren Illinois system and must separate the customer generation from the Ameren Illinois system either directly or through an auxiliary device such as a circuit breaker. The protective device should coordinate with the Ameren Illinois protection equipment and be capable of interrupting the available fault current at the device location. The customer is responsible for protecting the customer generation equipment in such a manner that faults or other disturbances on the Ameren Illinois system do not cause damage to the customer generation.

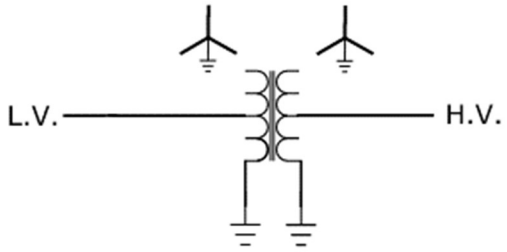
5.8. The customer shall provide lightning protection through either a static wire or lightning arresters for any line section which would cause an outage for Ameren Illinois facilities.

5.9. Ameren IL subtransmission lines are single point grounded at the source substation(s). To prevent ground relay de-sensitization, 69 kV and 34.5 kV customer generation interconnection transformers should have delta connected windings on the Ameren IL side. 59N protective schemes are also required to sense and clear ground faults on subtransmission feeders that may be fed from the generation customer.

5.10. Ameren IL 13.2kV, 12.47kV and 4.16kV distribution feeders employ 4-wire configurations with multiple neutral grounding connections. To mitigate ground fault overvoltage (GFOV) and load rejection over voltage (LROV) conditions, 4.16 kV, 12.47kV and 13.2kV RLG interconnection transformers for inverter based resources should have grounded wye-grounded wye winding configurations.

Three-phase, three-legged, core form transformers should not be used as internal magnetic coupling can disguise the loss of an incoming phase and prevent the proper shut-down of inverter-connected generation. This type of core form is more prone to ferro-resonance during open phase conditions and grounded-wye / grounded-wye winding configurations typically produce excessive tank wall heating during ground faults due to zero-sequence currents

circulating in the tank. Thus, a five-legged core transformer is recommended for DER interconnections.



Grounded-Wye Grounded-Wye with Inverters Compliant with IEEE 1547-2018 Section 7.4

Installations of non-inverter based generation or inverter based systems not compliant with IEEE-1547-2018 section 7.4 or existing interconnection transformers where BTM generation is added that could exceed 67% of the minimum load will be evaluated on a case-by-case basis by Ameren System Protection for GFOV and LROV mitigation requirements.

For interconnections at service voltage (<1000V) that require the use of a customer-installed transformer, the DER customer must carefully evaluate the operational characteristics of the system such that additional transformation beyond the POI does not prevent the DER system from being able to detect a loss of phase condition (applicable for three-phase interconnections). More information on transformer selection can be found in the Ameren Service Manual, Section 900.10.

5.11. Consistent with Section 2.F of the Ameren Illinois Standards and Qualifications for Electric Service filed with the Illinois Commerce Commission, the customer is responsible for obtaining all right of way and property needed to build and maintain the facilities required to make the connection to the Ameren system, including all necessary environmental, zoning, and/or special use permits. This includes building and maintaining a road suitable for accessing the Ameren-owned meter pole for operations, maintenance, testing, and inspection. Easements obtained by the customer from the POI to the point of ownership change shall be transferred to Ameren Illinois. The customer shall grant Ameren Illinois all necessary easements for Ameren Illinois facilities on customer property.

5.12. Ameren Illinois has experienced several issues of customer DER inverters tripping for high voltage, despite no excessive voltage being detected on the Ameren Illinois distribution system or delivery points. To prevent these types of issues, and based on installer experience and interactions with customer DER systems that experience production issues, DER systems should be designed for a 1% or less voltage rise between the inverter and the POI to reduce the likelihood of the inverter(s) tripping for overvoltage.

5.13. Power Plant Controllers: Effective for all new applications submitted after the approval date of this policy, all RLG DER interconnecting directly to primary distribution or

subtransmission voltage lines with a nameplate capacity of 500kVA must incorporate a Power Plant Controller (PPC) in their design.

The PPC must adhere to IEEE 1547-2018 standards as it pertains to maintaining Reference Point of Applicability (RPA) functions at the POI. The controller shall have real-time monitoring and control capabilities, including the ability to receive and respond to utility signals for active and reactive power control. It must also be capable of implementing power factor (PF) control for grid stability functions. In addition to regulating real and reactive power output at the POI, the PPC should be able to implement ramp rate controls for both up and down power adjustments, provide voltage regulation support, and facilitate seamless disconnection and reconnection processes. These capabilities are essential for maintaining grid stability and reliability as the penetration of distributed energy resources increases.

All sites utilizing a PPC must also be equipped with a SCADA-capable power quality (PQ) meter, such as a Shark 270 meter. This meter will be used to ensure that the DER plant is functioning correctly and can be utilized in situations where customers report power quality issues at or near the DER plant.

RLG operators are responsible for maintaining the PPC in good working condition and ensuring its continuous operation during electricity generation. The PPC must be configured to respond to Ameren Illinois' control signals within a timeframe specified by the company. Furthermore, RLG installations must be prepared to participate in future active network management schemes when required for grid stability and optimal DER integration.

Prior to interconnection approval, each RLG installation must undergo witness testing to verify PPC meter functionality and compliance with this policy. Ameren Illinois may require periodic testing and reporting to ensure ongoing compliance and optimal performance.

The implementation of this policy is justified by several factors. First, it ensures compliance with IEEE 1547-2018 standards for RPA functions at the POI. Second, it prepares for future integration with Distributed Energy Resource Management Systems (DERMS). Third, it enables Ameren Illinois to rely on RLG sites to perform grid stability functions, such as power factor control. Lastly, it enhances monitoring and control capabilities, allowing for more efficient grid management and improved reliability.

Ameren Illinois recognizes that there may be unique situations that warrant exceptions to this requirement. Requests for exceptions or waivers must be submitted in writing and will be evaluated on a case-by-case basis. This policy will be reviewed annually and updated as necessary to align with evolving technology, industry standards, and regulatory requirements.

By implementing these requirements, Ameren Illinois aims to create a more resilient, flexible, and efficient grid that can accommodate the growing integration of distributed energy resources while maintaining the highest standards of safety and reliability for all customers.

5.14. Collectively Owned Generation Facilities: Collectively Owned Generation Facilities (COGF) interconnecting with the Ameren distribution system must adhere to specific requirements to ensure safe, efficient, and compliant integration. Two primary interconnection options are available:

- Direct connection to the Ameren Illinois distribution line, which requires a step-up transformer, overvoltage and overcurrent protection, and standard generator protection equipment.
- Connection on the low voltage side of an existing Ameren Illinois service transformer, utilizing new or existing secondary voltage lines and standard generator protection equipment. COGFs must have dedicated service conductors and their own service installation to the AIC ownership point (transformer secondary bushings, secondary pedestal or existing secondary voltage lines).
- Connections to unmetered positions of CT cabinets or switchgear require that the DER installer provide pictures during application submission and review processes to allow Ameren Illinois Metering Engineering to review and approve the POI location for suitability.

Each COGF must have a dedicated Ameren Illinois revenue meter installed at the point of interconnection. Systems 200kW and above require a SCADA generation metering package, while those below 200kW use revenue metering without SCADA. COGFs cannot connect to existing transformers with internal current transformers (CTs), nor can they connect to the supply-side lugs of metering equipment. Furthermore, COGF meters must not be positioned behind existing revenue meters.

Interconnection requirements include adherence to Ameren Illinois Interconnection Policy. COGFs must have dedicated service conductors and their own service installation to the AIC ownership point (POI).

The choice between primary or secondary voltage interconnection can be made by either the customer or Ameren, with Ameren providing the necessary infrastructure and adhering to standard requirements. Local constraints, such as pole limitations, may influence this decision. While Ameren charges for the transformer, it is not rate-based as with load customers.

Typically, COGF ownership is limited to a single building owner. In cases of proposed co-ownership, regulatory guidance may be necessary, potentially requiring the formation of a single entity such as an LLC. Safety considerations, particularly regarding disconnect location accessibility for AIC and first responders, must be addressed.

All COGF installations must comply with the National Electrical Code (NEC), the Illinois Public Utilities Act, and Illinois Commerce Commission-approved tariffs for electric service and net metering. The allocation of generated power to individual units is managed by the property owner or manager through the Ameren Illinois Renewables Portal, with tenants receiving corresponding financial credits on their monthly electric bills.

COGF DER installations that utilize a limited export or non-export control mode must adhere to the following requirements:

- Limited export systems for COGF DERs must be designed to ensure that the export limit can account for real-time customer load of all customers served by the COGF.
- A failsafe for the export control must be in place and be able to be tested during the witness test.
- For any export limit applied to a COGF that connects directly to Ameren Illinois primary lines or other Ameren Illinois equipment exclusive of shared equipment with the load, a full nameplate capacity check must be performed specific to those facilities subject to full nameplate output.
- All COGF export limits shall be reviewed on a case-by-case basis by Ameren Illinois engineering to ensure all requirements are met.

These comprehensive requirements are designed to facilitate the integration of COGF systems into Ameren's distribution network while ensuring safety, regulatory compliance, and equitable distribution of benefits to property owners and tenants.

6. Standards for Evaluating Interconnection Requests and Methodology for Determining the Scope of System Modifications and Cost Estimates

To ensure that the system requirements outlined above are maintained, Ameren Illinois screens all potential DER interconnections using the interconnection study procedures mandated by ICC Administrative Code Part 466 and 467 (specifically, subparts 466.90, 466.100, 466.110, 466.120, and 467.70 define the various review processes). Computer-based system models are used to assist with this process. These studies are performed in the order in which the applications are received based on the queue, and existing hosting capacity is allocated on a first-come, first-served basis. Electric system upgrades are allocated to the first project that violates the criteria defined in Section 4 of this document, in accordance with the Admin Code's "cost-causer pays" philosophy. This process is standardized to ensure that all applications are reviewed and studied consistently throughout the entire Ameren Illinois territory.

Co-located three-phase RLG interconnections are sites that are owned by the same customer and are sited on adjacent parcels of land. If it is possible to protect two or more co-located sites with the same protective device while maintaining coordination with other protective devices on the circuit, the standard option will be to utilize a single protective device for all co-located sites, which would minimize the interconnection cost assessed to the customer. In cases where this is deemed infeasible, the alternative approach would require that an additional device be installed at each metering point, which would come at the customer's expense and increase utility maintenance cost and system complexity, but may slightly reduce the likelihood that all the generation is disconnected during a system disturbance. The results of interconnection studies are used to determine which, if any, system modifications will be required to interconnect the proposed DER without causing negative system impacts. This shall include system modifications required to serve the proposed DER during subtransmission system switching contingencies, consistent with other Ameren Illinois subtransmission planning processes. Level 1 interconnection projects are subject to a $200 interconnection cost cap; any additional system modification costs are borne by the rate base per CEJA and the Admin Code. For Level 2 and above projects, the applicant bears the cost of these modifications, including installation of any required Ameren Illinois facilities at the POI, if they would like to proceed with interconnection upon receiving the results of the interconnection study. System modifications required for interconnection must be completed prior to interconnection of a customer's DER system. Ameren Illinois strives to meet customer requested deadlines and in-service dates, but project completion is ultimately subject to material lead times which can be affected by shortages and other factors. A list of most typical examples of these modifications (commonly referred to as interconnection costs) is listed below. A list of estimated costs for system modifications are listed in the table at the end of this section. Please note that location and equipment specific conditions may cause actual cost estimates to deviate from the estimated costs below, and that these values are provided for informational purposes only.

6.1. Any voltage regulators that will experience reverse power flow due to the proposed DER must have controllers able to detect and correctly operate with co-generation. SCADA communications must be added to these regulators as well to ensure voltage limits are maintained.

6.2. Any substation load tap changer (LTC) that experiences reverse power flow due to the proposed DER must have controllers able to detect and correctly operate with co-generation. SCADA must be added to these LTCs as well to ensure voltage limits are maintained.

6.3. Any hydraulically controlled recloser that will experience reverse power flow due to the proposed DER must be replaced with an electronically controlled recloser. This is to ensure a recloser does not open and reclose before an inverter is able to detect a loss of source and cease generation, which could cause the parallel sources to be out of phase.

6.4. The ratings of surge arresters on the high side of delta connected distribution substation transformers may need to be evaluated if the transformer could experience reverse flow under light loading conditions and is protected by a circuit switcher or breaker (three phase tripping device) or if the aggregate DER connected to the distribution transformer could be large enough to support the minimum loading of the subtransmission line if the subtransmission line becomes isolated from its source. If one of these conditions exists for a proposed DER, the surge arresters must be replaced with arresters that have a higher voltage rating and a 59N scheme must be added.

6.5. When a proposed DER exceeds FVV criteria, some or all of the line conductor between the proposed DER and the substation will need to be replaced with larger conductor to reduce line impedance, which in turn reduces FVV. Line reconductor costs can vary widely due to geographic diversity, population density, existing system condition, and a litany of other circuit-specific factors. Line reconductoring costs depend on several conditions including line condition, geographic constraints, line voltage, and the potential of multiple circuits sharing the same pole line adding complexity.

6.6. Similar in cost to a line reconductor, a line extension may be required to serve a proposed DER that is not located at an existing service point. Most DER-related line extensions will be three-phase line extensions.

6.7. Service transformer replacement is required in cases where the output of a proposed DER exceeds the nameplate rating of the existing service transformer.

6.8. Substation transformer upgrades may be required to increase the thermal rating of substations to support DER interconnection projects. When a transformer rating violation is identified in an interconnection study, Ameren Illinois will consider a transformer upgrade when the transformer is smaller than the largest standard equipment size. The addition of new transformers in substations will not be considered during an interconnection study due to the complexity and time required to facilitate a substation expansion project.

6.9. For DER installations where DTT functionality is required, a communications device may be required to be added to the substation recloser. In cases where the existing substation protective device is incompatible with the communications device, the substation protective device must be replaced as well to facilitate this requirement.

6.10. As determined by Ameren Illinois System Protection Engineering, in some cases hot-bus-dead-line reclosing and synchronous check reclosing may be required to be added at

substations upstream of customer owned DER. This may require a voltage transformer to be added at the line-side substation terminal.

6.11. Additional system work and associated costs not covered in this document may be necessary to safely and reliably connect a new DER system.

6.12. Interconnection Facilities:

6.12.1. For RLG DER interconnected on a distribution voltage circuit, the following equipment will be required at the POI: three-phase tap, electronically controlled SCADA-capable recloser, primary metering, and the associated poles and conductor to facilitate installation.

6.12.2. For RLG DER interconnected to a subtransmission system via a line tap (singular or co-located), the following Ameren-owned equipment will be required at the POI: (1) three-phase line tap; (2) main line load break switch on both sides of the tap; (3) electronically controlled SCADA-capable recloser; (4) primary metering; (5) associated poles and conductor to facilitate installation.

6.12.3. For BTM DER with an AC nameplate rating of 200 kW AC and larger, SCADA-capable generation metering is required. The SCADA metering package is provided by Ameren Illinois to the customer at the customer's expense. The SCADA-capable meter will connect to the customer's instruments and be set up by Ameren Illinois personnel during the witness test.

6.12.4. For renewable generation systems combined with energy storage, separate metering may be required for the energy storage in cases where it is either AC coupled with the generation, or DC coupled with the generation using a bi-directional inverter. See section 4.7.1 of this document for more information.

Estimated Costs of Typical Interconnection Upgrades and Facilities Updated November 18, 2025		
Description of Upgrade	Typical Cost Range (Low)	Typical Cost Range (High)
Distribution voltage electronic recloser, pole mounted	$100,000	$150,000
1 mile of distribution voltage line reconductoring or buildout	$516,000	$774,000
Distribution voltage regulator, pole mounted (per phase)	$98,000	$147,000
Distribution voltage POI equipment, (tap, recloser, and metering)	$128,000	$192,000
100kVA Padmount transformer (single phase)	$7,000	$10,500
Distribution voltage electronic recloser, substation	$225,000	$337,500
Substation Intellinode + communications for DTT	$40,000	$60,000
Distribution voltage substation voltage regulators (three-phase)	$360,000	$540,000
Distribution substation transformer replacement with 14 MVA unit	$1,800,000	$2,700,000
Distribution substation transformer replacement with 22 MVA unit	$3,100,000	$4,650,000
Voltage regulator control upgrade + SCADA communications package	$85,000	$127,500
SCADA BTM generation metering package	$27,000	$40,500
SCADA communications package (substation equipment)	$10,000	$15,000
Distribution voltage primary metering, pole mounted	$11,000	$16,500
Line VTs for distribution substation protection upgrades	$175,000	$262,500
Bus VTs for distribution substation protection upgrades	$300,000	$450,000
Substation transformer lightning arrestors (three-phase)	$60,000	$90,000
Transmission substation transformer lightning arrestors (three-phase)	$70,000	$105,000
Transmission substation CCVT (per phase)	$195,000	$292,500
Labor charges related to system protection settings changes	$20,000	$30,000
SEL-651R for 59N Scheme (system protection)	$70,000	$105,000
59N with Existing CCVTs and Relays (system protection)	$75,000	$112,500
SEL-2411 Capacitor Controller (system protection)	$70,000	$105,000
LOR and Rework Sub-T Bus Protection (system protection)	$50,000	$75,000
Switchgear Relaying Upgrade (system protection)	$130,000	$195,000
De-energized Tap Position Change (substation)	$35,000	$52,500
LTC Control (VO SCADA Package)	$105,000	$157,500
Single relay replacement (system protection)	$70,000	$105,000
Single line panel replacement (system protection)	$240,000	$360,000
Single transformer panel replacement (system protection)	$335,000	$502,500

Electrical crew mobilization for sub. work	$8,000	$12,000
Civil crew mobilization for sub. work	$8,000	$12,000
Drill Pier Rig crew mobilization for sub. work	$15,000	$22,500
Mobile Substation transformer installation and transport	$25,000	$37,500
34kV electronic recloser, pole mounted	$85,000	$127,500
69kV electronic recloser, pole mounted	$500,000	$750,000
69kV metering instruments, pole mounted	$85,000	$127,500
34kV metering instruments, pole mounted	$66,000	$99,000
34kV GOAB switch, pole mounted	$54,000	$81,000
69kV GOAB switch, pole mounted	$79,000	$118,500
Subtransmission line tap pole	$14,000	$21,000
1 mile of subtransmission voltage voltage line reconductoring or buildout	$750,000	$1,125,000
Subtransmission substation transformer replacement with 22 MVA unit	$3,500,000	$5,250,000
34kV substation terminal addition	$680,000	$1,020,000
34kV capacitor bank, pole mounted	$40,000	$60,000
Subtransmission OPGW shield wire replacement	$55,000	$82,500

7. Testing and Commissioning

7.1. Purpose

All DER interconnections to the Ameren Illinois EPS, including Level 1 facilities, are witness tested to ensure safe and reliable system operation. A witness test consists of simulating utility system outages to ensure that parallel generation responds accordingly and does not create an unintentional island. During the witness test, Ameren Illinois personnel also verifies that the DER system installed by the customer aligns with the system proposed during the application process. The witness test is scheduled at the time that the DER customer submits documentation informing Ameren Illinois that their construction is complete. While larger systems (Level 2 and above) typically require scheduling a test with multiple representatives from Ameren Illinois and the DER customer present, Level 1 witness tests are completed within 15 business days as a technician becomes available to complete the test.

Witness testing is a critical step in ensuring that DER is connected to the system safely. In our experience, at all levels of interconnection – regardless of whether the installer is a local firm or a national developer – the tests have prevented unsafe conditions from being created by DER interconnection projects. Not only is an unintentional island dangerous for customers and equipment served temporarily by the island, but during a grid outage it may create a risk of contact with energized equipment at ground level for utility personnel as well as the general public. There are also site-specific situations that must be reviewed on-site after construction is complete that cannot be addressed simply by performing an interconnection study or through the use of a screening question. For example, use of step-up or step-down transformers between POI and the inverter terminals can cause a certified inverter to fail to detect a grid outage and cease power output, which can only be identified during an on-site witness test. Once all test conditions are satisfied and any issues are resolved, the DER system is issued permission to operate ("PTO").

In addition to the DER system performance testing detailed above, Ameren Illinois may, but is not required to, identify wiring and electric equipment practices that may raise safety and/or reliability concerns for Ameren and/or the DER customer on the customer side of the point of delivery. Ameren Illinois reserved the right to identify and require the correction of such concerns prior to connection of service. Please see the Ameren Illinois Witness Test Criteria and Ameren Service Manual for more information.

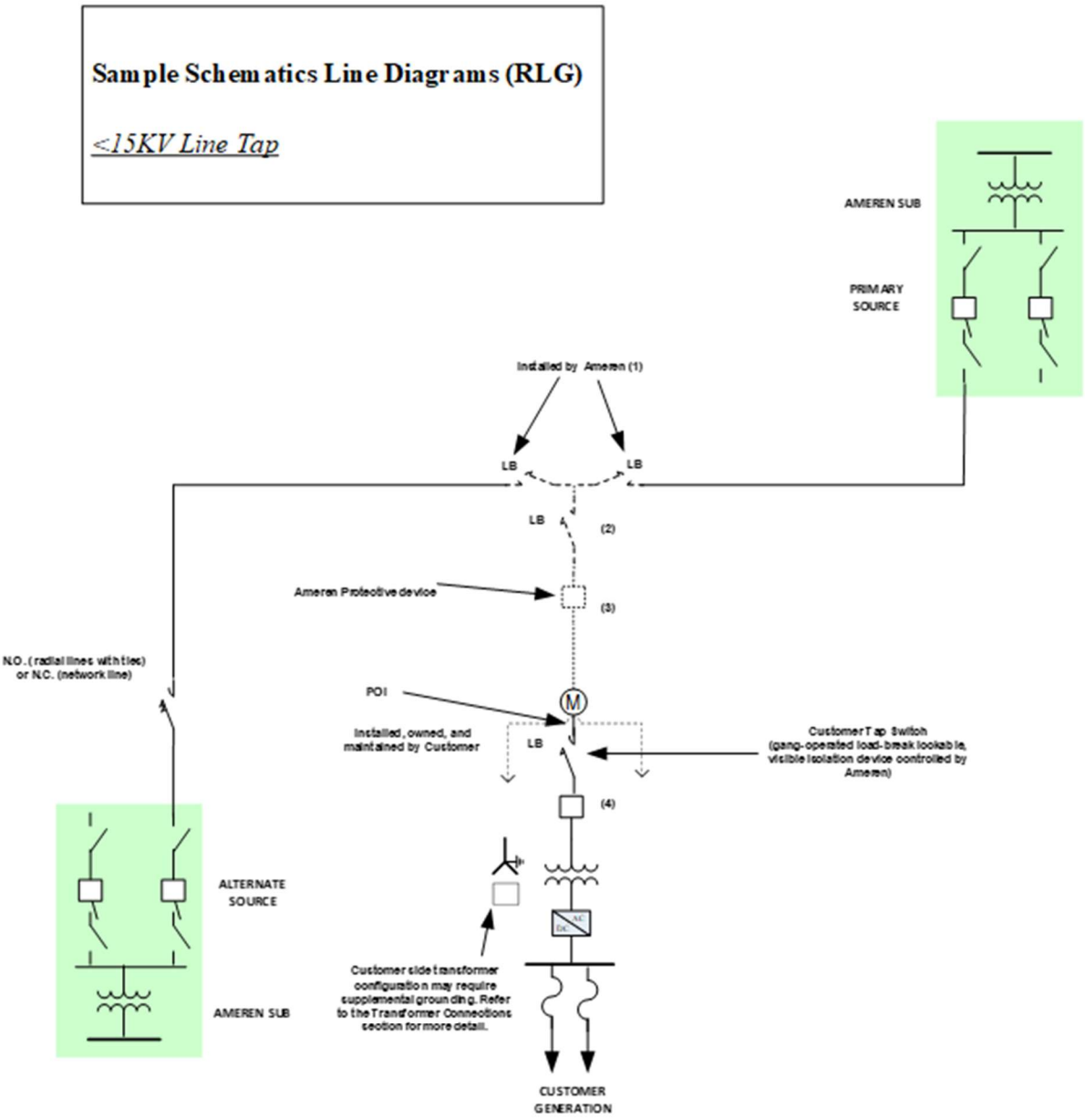
7.2. Permission to Operate

If all test conditions are successfully met during the on-site witness test and a power quality meter was not used during the test, then the customer will receive a written conditional permission to operate. An official and permanent PTO will be issued by Ameren Illinois' DER Application Team, typically within two business days of the witness test. If a power quality meter is used during the test, the recorded data must be reviewed by Ameren Illinois engineering before a full permission to operate can be awarded. At Ameren Illinois' sole discretion, the generation may remain connected and generating while the data is reviewed in the form of a conditional PTO. Otherwise, the generator disconnect switch must be locked open until a permanent PTO is issued by the DER Application team. Witness test results will be provided to the customer within 48 hours of the witness test.

If on-site test conditions are not met during the witness test, or if the power quality meter data raises an issue with the operation of the generator, another witness test will be scheduled within 30 business

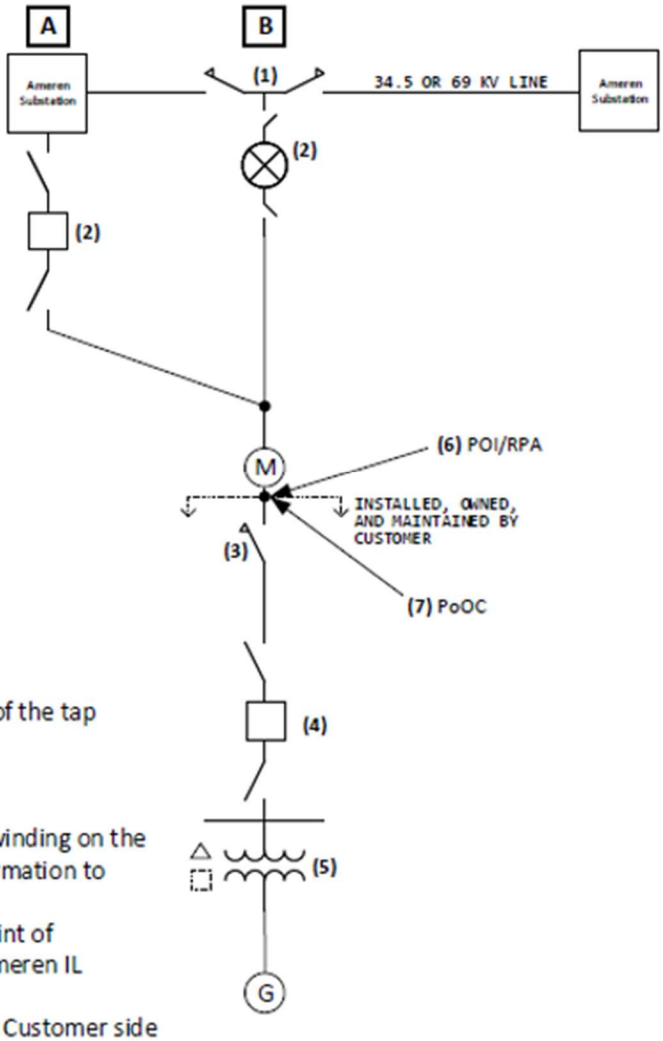
days to allow the customer time to resolve any problems. The 30 business days may be extended upon the mutual agreement of Ameren Illinois and the customer, so long as no other queued DER installations are affected by the extension

Appendix 1: Typical Configuration Diagrams for RLG DER Systems



(1) Load-break switches at either side of the tap is optional.
(2) Disconnect switches upstream of Intellirupter required if no additional pole needed for installation.
(3) Ameren installed and owned S&C Intellirupter (or future standard SCADA capable recloser)
(4) Customer installed protective device. Ameren IL recommends an electronically controlled protective device that is programmed to prevent overvoltage during a single phasing event by opening for a loss of phase. This has been required to pass the witness test for many RLG installations

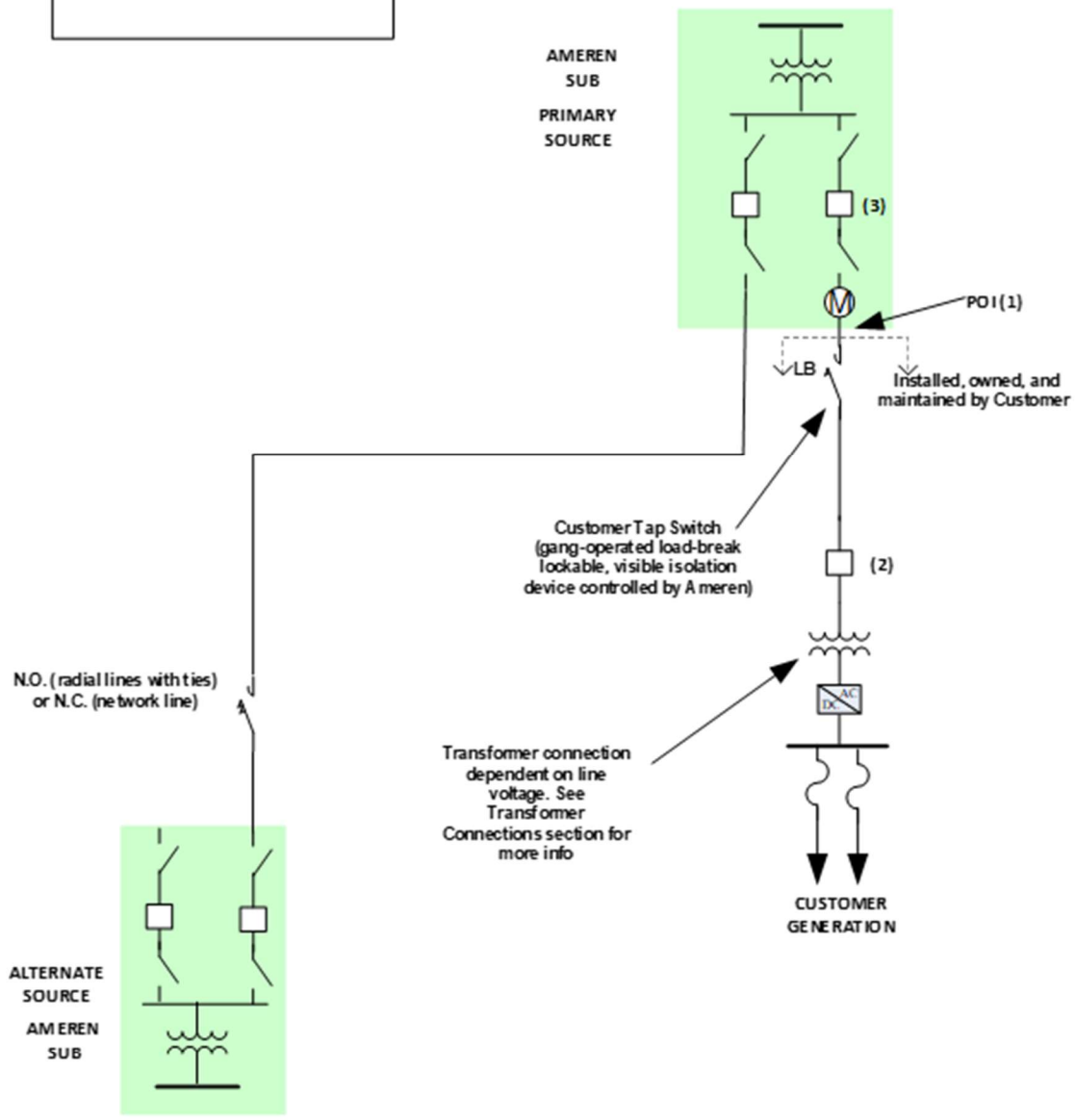
Typical Interconnection Configurations for Remotely Located Generation – Subtransmission



Interconnection Configurations Types
A: Direct substation connection
B: Line Tap

(1) Main line disconnection switches on both sides of the tap
(2) Ameren-owned protective device
(3) Customer Tap Switch
(4) Customer-owned protective device
(5) Main step-up transformer(s) must have a delta winding on the utility side. Customer must provide step-up transformation to utility primary voltage at the POI.
(6) Point of Interconnection (POI) and Reference Point of Applicability (RPA) is on the Customer side of the Ameren IL revenue meter.
(7) The Point of Ownership Change (PoOC) is on the Customer side of the dead-end clamps on the primary meter pole. The primary meter pole cannot be used as tension change structure.

Substation Bus Tap



(1) Point of Interconnection (POI) may be on a substation bus if supported by an Interconnection Study.
(2) If electronically controlled, customer installed protective device shall prevent overvoltage during a single phasing event by opening for a loss of phase. Required to be electronically controlled device for 34kV and above, highly recommended for 15kV and below.
(3) SCADA capable electronic recloser

Appendix B: Sample Schematics Line Diagrams for Behind the Meter DER Systems

Notes for BTM SLDs:

SCADA

(1) Intellirupter: May be required based on generator/DER size and/or the presence of a Distribution Automation scheme on the feeder serving the Point of Interconnection (POI).

Disconnects & Switches

(2) Customer Service Main Disconnect: This load protection device can be gang operated fused disconnect switch or circuit breaker.

(3) Generator/DER/ESS Disconnecting Means: Gang operated fused disconnect switch or circuit breaker. May be connected supply/line side (between the revenue meter and service main disconnect) or load side (downstream of the Customer Service Main Disconnect). If connected line side, the disconnect must be service rated. If gang operated fused disconnect switch is used on system greater than 1000V it must have a visible air-gap. If circuit breaker is used on systems greater than 1000V, then it must be on a rackable frame allowing for a visible open. For secondary systems (operating under 1000V), a visible indication of switch position is required, but the presence of a visible air gap is optional. This switch must be located outdoors, be accessible to the utility and first responders, and be lockable in the open position; if it is not, an additional switch will be required between the POI and the DER system to meet these requirements.

(4) Readily accessible generation disconnect: additional switch required if (3) does not meet the utility accessible and lockable requirements.

- For secondary systems, a lockable, visible indication of switch position is required, but the presence of a visible "air gap" is optional. For primary systems a visible "air-gap" is required.
- DER and ESS systems shall maintain separate disconnects to facilitate witness testing and to meet the requirements of the latest edition of the NEC and Ameren Electric Service Manual.

(6) Meter Disconnect Switch: Required if meter #5 is installed. (we could strike the rest of this except (5) and (7) if we removed diagram on P.25. More info on that page)

(10), (11), (12) and (13) are Meter disconnect Switches (Can be Circuit Breaker or other acceptable means with visible indicators of OFF/ON position). {(10) and (11) are optional if (3) is installed. However, (10) and (11) are useful to allow segmented isolation. Depending on proximity to POI, (10) and (11) could be used instead of (4)}

Meters

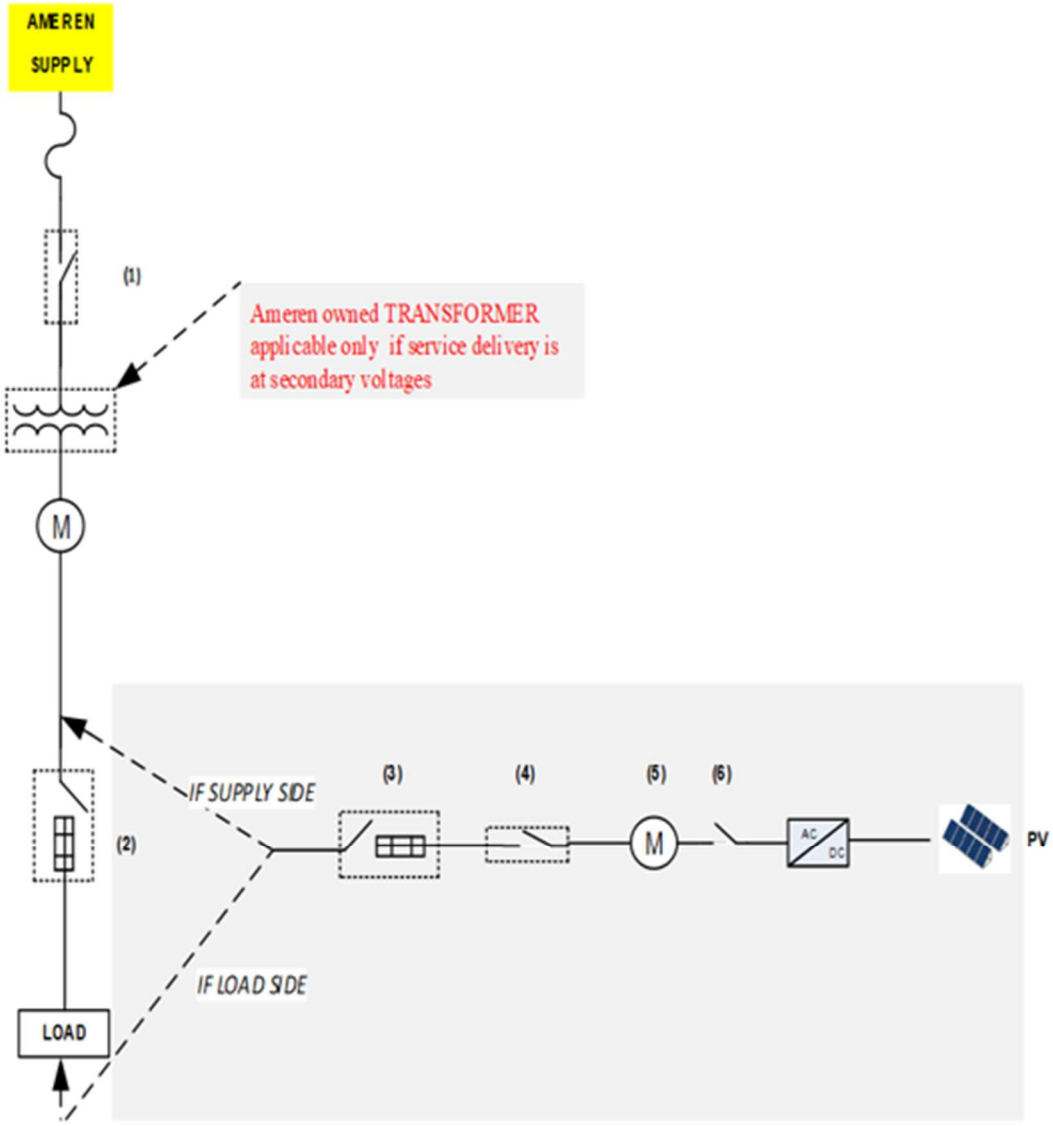
(5) SCADA Enabled SCADA Capable Production Meter with Intellinode: Meter is owned by Ameren and connected to instrument transformers that are owned by the customer.

(8) and (9) are AIC DER Production Meters that are revenue grade. Meters are owned by Ameren and associated instrument transformers are owned by the customer.

Inverter Specification

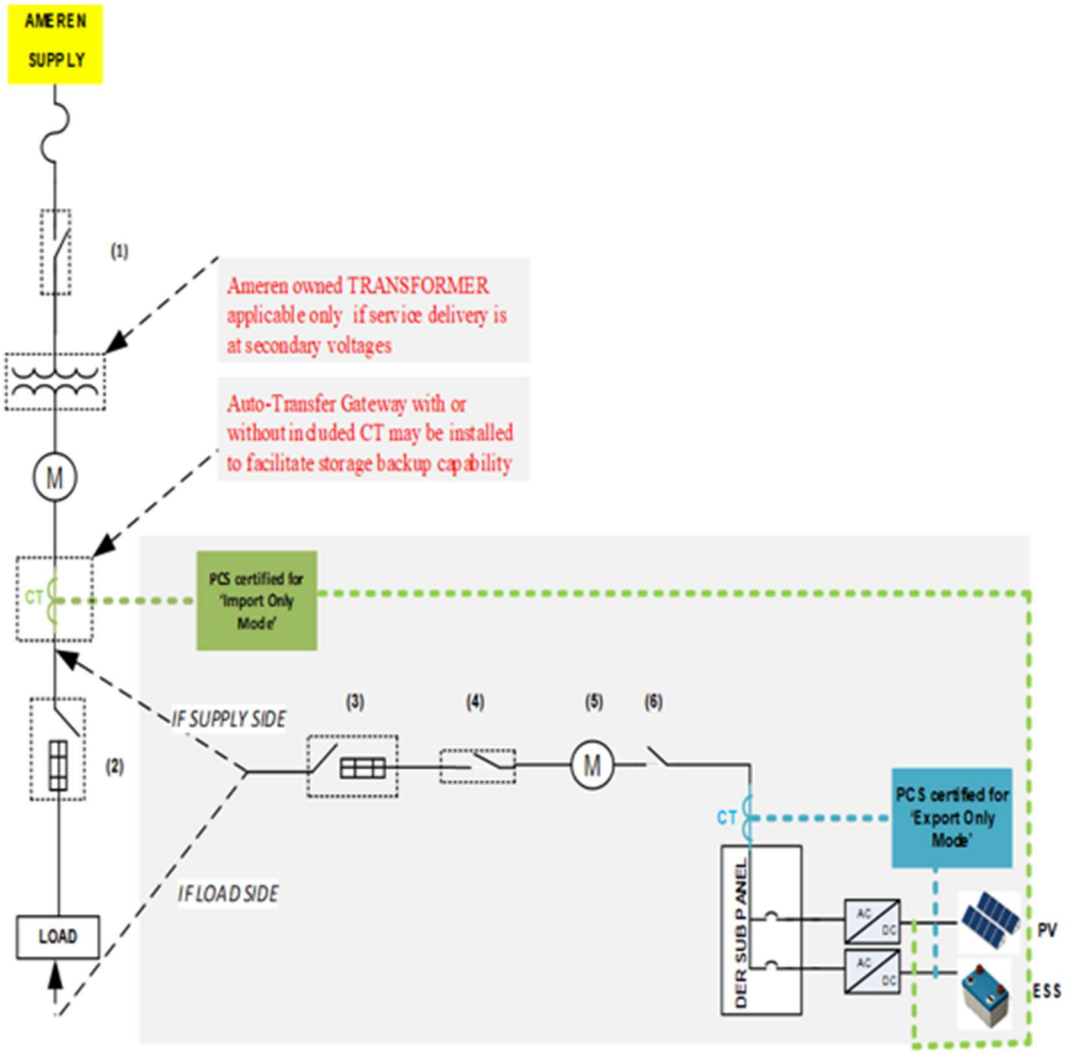
(7) A 'Two Quadrant' Inverter. The 2 Quadrant refers to injection only for real power and required for the DC coupled ESS in 'Type 1-Ex'

PV/Wind only


AMEREN
SUPPLY
(1)
Ameren owned TRANSFORMER applicable only if service delivery is at secondary voltages
M
IF SUPPLY SIDE
(2)
(3)
(4)
(5)
(6)
M
AC
DC
PV
IF LOAD SIDE
LOAD

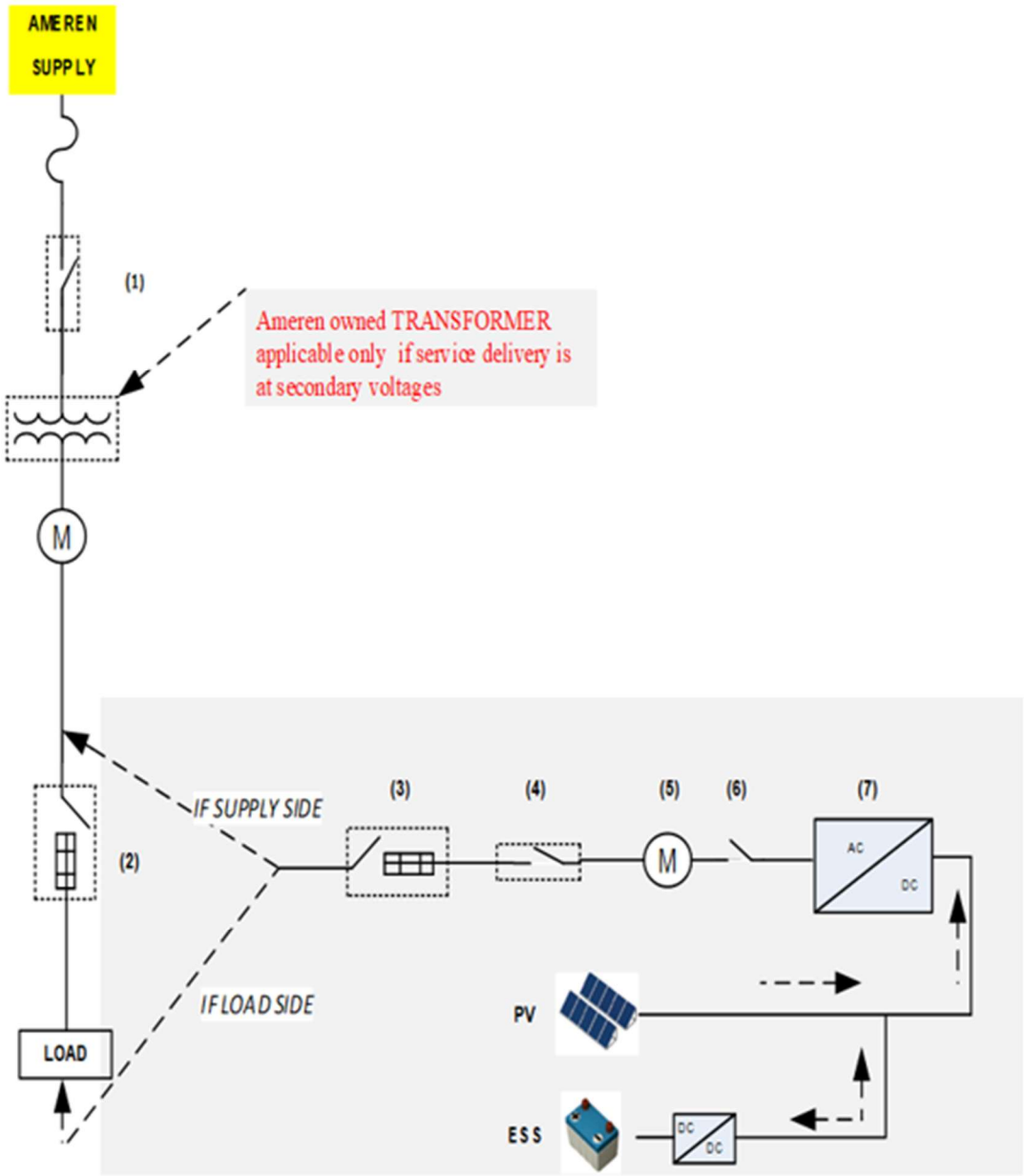
ESS Configurations that utilize PCS

Applicable Configurations	PCS Requirement
Type 1-NEx	**NO Exchange** requirement can be fulfilled through a combination of 'Export Only' and 'Import Only' PCS
Type 1-Ex	'Export Only'
Type 2-NEx	'Import Only'
Type 3-Ex	'Import Only'



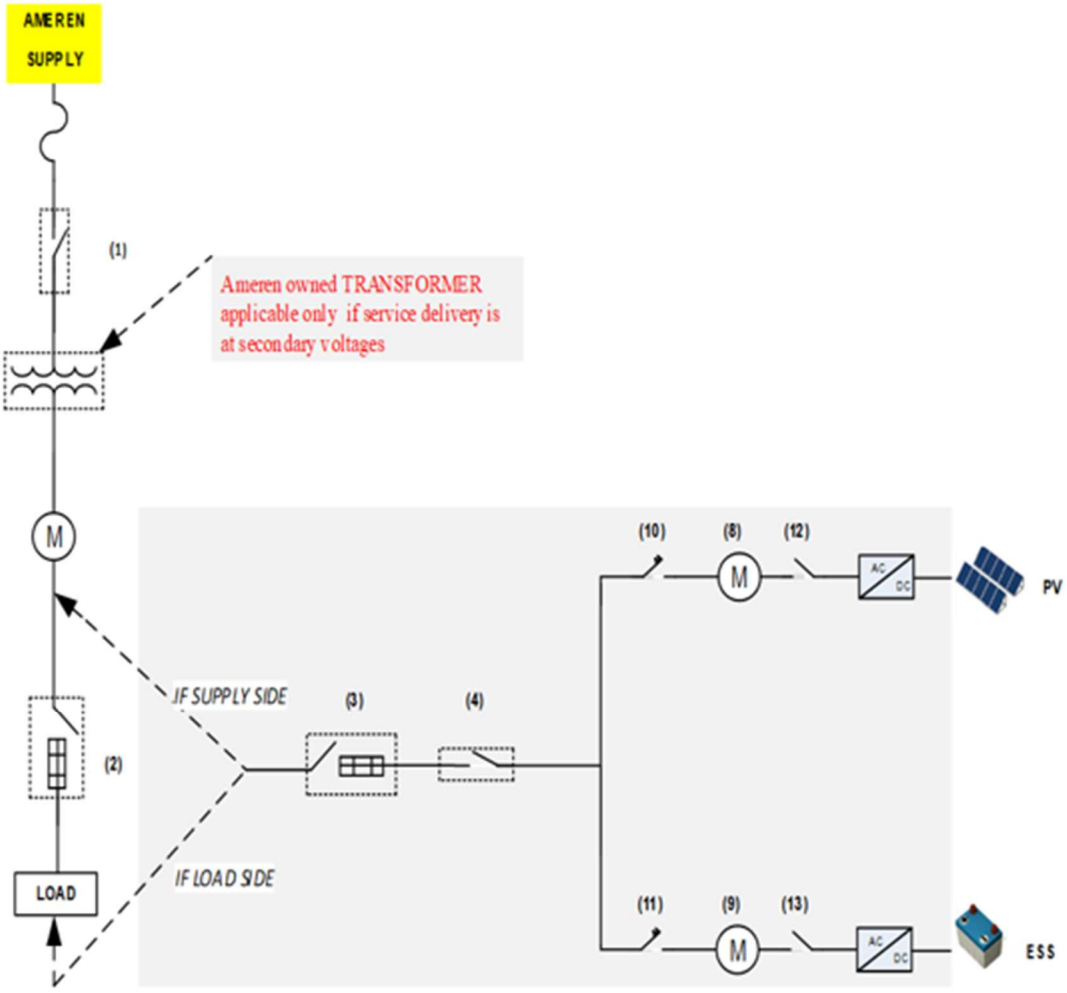
ESS Configuration that utilize a DC Coupled 2 Quadrant Inverter

Applicable Configurations	Hardware Requirement
Type 1-Ex	**DC Coupled with 2 Quadrant Inverter (Export Allowed)**



ESS Configuration that utilize Separate PV & ESS Meters

Applicable Configurations	Hardware Requirement
Type 2-NEx	**Separate PV and ESS Meters**



ESS Only (No PV)

Applicable Configurations	Hardware Requirement
Type 3-NEx	'Import Only' and/or 'No Export Relay'
Type 3-Ex	No Requirement