A Framework for Determining The Costs and Benefits of Renewable Resources For Southern Company

Revised: 1/12/22

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SECTION 1 2022 IRP INTRODUCTION

Driven by market conditions and regulatory requirements, Southern Company and Georgia Power Company ("the Company") worked to establish a methodology to appropriately reflect the costs and benefits of intermittent renewable resources across the Southern Company electric system. The Company introduced the renewable cost benefit framework ("RCB Framework") in the 2016 integrated resource plan ("IRP"). Pursuant to the Stipulation approved by the Georgia Public Service Commission ("GPSC" or "Commission") in Georgia Power's 2016 IRP (Docket No. 40161), the Company worked collaboratively with the Commission's Public Interest Advocacy Staff ("Staff") to refine and clarify the application of the RCB Framework by Georgia Power. In December 2016, Georgia Power and Commission Staff filed a Joint Recommendation regarding implementation of the RCB Framework, which the Commission subsequently approved. The Company continued to apply the RCB Framework to the evaluation of renewable projects and pricing for programs offered in the 2019 IRP (Docket No. 42310). Pursuant to the Stipulation approved by the Commission in Docket No. 42310, the Company and Commission Staff made a good faith effort to resolve issues raised by Staff in the 2019 IRP. These specific issues included the evaluation of the RCB Framework components of deferred generation capacity, generation remix, and support capacity. In January 2020, the Company filed an RCB Framework Compliance Filing documenting those meetings and remaining issues. As the RCB Framework is a living document, the Company has made several improvements to the RCB Framework for the 2022 IRP as described herein.

In continued support of reliable and cost-effective renewable expansion, the Company has expanded this iteration of RCB analysis to include industry-leading renewable integration assessments examining the impacts of substantial renewable growth on the system, which provide unique insights into the challenges with, opportunities accompanying, and solutions that enable significant renewable expansion. These assessments capture the interactions of large renewable penetration levels with other system resources necessary to support reliable renewable integration. The Company used stochastic reliability modeling tools to complete an intra-hour reliability assessment that determines solar integration costs while accounting for weather, unit outages, and similar uncertainties. The Company continuously seeks to improve its modeling and analytical capabilities to make decisions in the customers' best interest. This new renewable integration study is one of those improvements; representing a significant increase in the analytical sophistication associated with renewable expansion. The RCB Framework incorporates this new information.

Many of the core components of the RCB Framework remain consistent with prior iterations. These components include avoided energy costs, deferred generation capacity costs, avoided transmission losses, deferred transmission investment, and avoided distribution losses. While maintaining these core components, the updated RCB Framework incorporates the previously discussed analytical and methodological improvements. Additionally, the Company seeks to streamline and simplify the RCB framework. Notably, the Company is removing the Generation Remix category and replacing the Support Capacity category with a comprehensive Integration Cost component. The Integration Cost component accounts for the Operating Reserves needed to mitigate the impacts of solar volatility and uncertainty previously accounted for in Support Capacity. Lastly, as the Integration Cost ensures that appropriate balancing services are available, the individual components for Ancillary Services and Bottom Out Costs are no longer needed and have been removed. Other elements previously held in "placeholder" status have been determined to be unnecessary at this time and have also been removed.

SECTION 2 EXECUTIVE SUMMARY

Introduction

Renewable generation resources remain an important component of the Southern Company electric system. Renewable resources have different operating characteristics from conventional generating resources, including limited dispatchability and instantaneous volatility. Therefore, an economic analysis of renewable resources will take into consideration that fleet operations is affected by the variability of renewable resources. To support and inform renewable planning and procurements, Southern Company has established a methodology for determining the costs and benefits of renewable resources on the Southern Company electric system (RCB Framework or RCB). The RCB Framework guides resource planning and procurement activities related to renewable resources and ensures economic and reliable renewable resource integration for the Southern Company retail electric system.

Components Included in the Cost-Benefit Analysis

Southern Company has identified key components of the costs and benefits of adding renewable resources on the Southern Company electric system.

There are two primary categories of renewable generation facilities that differentiate the generation type being evaluated

1. **Utility Scale (“US”):** Large-scale renewable generation facilities are generally connected at the transmission level (“US-T”) but may also be connected at the distribution level (“US-D”).
2. **Distributed Generation (“DG”):** Small-scale renewable generation facilities are connected at the distribution level and are intended to serve local load.

See Appendix A for single-line diagrams of the categories.

Table 1 shows the list of components included in the Southern Company RCB Framework and whether each component is a cost or a benefit. Each component is discussed in further detail in Section 3.

Table 1: In Scope Renewable Cost Benefit Components

Component	Utility Scale	Distributed Generation
Avoided Energy Costs	Benefit	Benefit
Deferred Generation Capacity Costs	Benefit	Benefit
Avoided Transmission Losses	N/A	Benefit
Deferred Transmission Investment	N/A	Benefit
Avoided Distribution Losses	N/A	Benefit (1)
Integration Costs	Cost	Cost

Notes: (1) Determined by where it is connected to the distribution system for DG.

SECTION 3 BACKGROUND AND PURPOSE

Renewable energy is a fast-growing segment of electricity generation in the United States. Southern Company is committed to the cost-effective addition of renewable resources to benefit customers. This commitment requires a comprehensive understanding of the costs and benefits of renewable resources, both those common to other generation technologies and those unique to renewable resources. This understanding is essential for the company’s

Integrated Resource Planning process, resource procurement activities, and reliable fleet operation.

Southern Company has developed and updated this RCB Framework for determining the appropriate costs and benefits of renewable resources. The RCB Framework establishes the methods by which the Company will determine the impact of renewable resources on the economics and reliability of the generation fleet. The operating characteristics, including limited dispatchability, generation uncertainty, and generation volatility, are addressed.

The RCB Framework provides the Company, regulators, and stakeholders a consistent understanding of how renewable resources will be implemented in the Company's planning and procurement activities. The RCB Framework is intended to address common utility planning items based on established and emerging industry practice. The RCB Framework is not intended to address every element that could affect utility resource decisions; the regulatory process requires the flexibility to consider many qualitative and local jurisdictional issues.

SECTION 4 RENEWABLE COST-BENEFIT COMPONENTS

Definitions

These are general terms and acronyms used in this document.

- **Avoided Energy Costs**: The marginal energy-related costs avoided on the Southern Company electric system. These costs include marginal replacement fuel costs, variable operations and maintenance, fuel handling, environmental compliance costs, intra-day commitment costs, and applicable transmission losses when the renewable generation served the load.
- **Economic Carrying Cost ("ECC"):** The capital and fixed operations and maintenance ("FOM") related to the cost of deferring an investment for one year. ECC represents the avoided cost of an investment for a given year.
- **Capacity Worth Factor Table ("CWFT"):** The relative allocation of the capacity value across the year. It represents the relative reliability risk (i.e., risk of unserved energy) in one hour relative to all other hours.
- **Distributed Generation ("DG"):** DG renewable is metered separately from the load and delivered directly to the grid. This type of facility is typically less than 125% of the connected load.

- **Utility Scale-Distribution (US-D):** US-D renewable facilities connections are at the distribution level on a dedicated distribution feeder.
- **Utility Scale-Transmission (US-T):** US-T renewable generation facilities are connected at the transmission level.
- **Variable Energy Resource ("VER"):** A VER produces electricity by an energy source that (1) is renewable, (2) cannot be stored by the facility owner or operator, and (3) has variability that is beyond the control of the facility owner or operator. (This definition was established by FERC: *Integration of Variable Energy Resources Notice of Proposed Rulemaking*, FERC Stats. & Regs. ¶ 32,664 at P64 (2010).)

Components Summary

This section provides a detailed summary of the components in the Southern Company RCB Framework.

Avoided Energy Costs

Avoided Energy Costs for this report represents the marginal energy-related costs not incurred on the Southern Company electric system when renewable generation serves the load. As discussed in Section 4, the renewable-weighted Avoided Energy Costs represent the energy cost expected to be avoided during the renewable generation hours.

Avoided Energy Costs is a project-specific RCB component. Cost components are: marginal replacement fuel costs, variable operations and maintenance, fuel handling, environmental compliance costs, intra-day dispatch costs, and transmission losses associated with other resources.

Because many renewable resources have limited dispatchability, they can contribute to overgeneration when the renewable output exceeds system demand. This could result in curtailment of some renewable resource output. During periods of curtailment, there is no avoided energy cost for additional generation, and the Avoided Energy Costs value will be zero.

Avoided Energy Costs is a ***benefit*** in the RCB Framework.

Deferred Generation Capacity Costs

Deferred generation capacity costs are an RCB project-specific component. Renewable resources contribute to the reliability of the electric system, which in turn defers the need for other capacity resources. The Southern Company Integrated Resource Planning process establishes the level of capacity required to serve customer demand reliably. The operating characteristics of some renewable resources could limit their contribution to capacity requirements. The renewable resource contribution to the capacity requirement is called the Incremental Capacity Equivalent ("ICE") or the Effective Load Carrying Capability ("ELCC"). The ICE or ELCC determines how much other generation capacity can be deferred by the renewable resource. Renewable resources only contribute to capacity requirements if the resource has an established obligation to perform, such as a regulatory certification or executed contract.

Considering the appropriate ICE or ELCC, Deferred Generation Capacity Costs is reflected as a ***benefit*** in the RCB Framework.

Avoided Transmission Losses

Some renewable resources, such as those connected to the distribution system and intended to serve local load, do not use the bulk transmission system. These resources avoid the energy losses associated with moving energy across the transmission system. They could reduce the total capacity requirement for the system, since capacity is required to generate transmission losses. To reduce the total capacity requirement without compromising system reliability, the renewable resource must have an established obligation to perform.

Avoided Transmission Losses is reflected as a ***benefit*** in the RCB Framework for applicable DG resources.

Deferred Transmission Investment

Some renewable resources, such as those connected to the distribution system and intended to serve local load, do not use the bulk transmission system. These resources could reduce the demand placed on the transmission system and defer or avoid otherwise needed transmission investments, depending on the current and future state of the transmission system and the location of the renewable resources. As with deferred generation capacity, the renewable resource must have an established obligation to perform in order to defer or avoid transmission investments without compromising system reliability.

Deferred Transmission Investment is reflected as a ***benefit*** in the RCB Framework for applicable DG resources.

Avoided Distribution Losses

Some renewable resources, such as those connected at the customer site and intended to serve local load, do not fully use the local distribution system. In addition to avoiding transmission losses, these resources also could avoid distribution energy losses. They potentially reduce the total capacity requirement for the system, since capacity is required to generate distribution losses. To reduce the total capacity requirement without compromising system reliability, the renewable resource must have an established obligation to perform. The amount of impact on the system is dependent on where the resource is located on a specific distribution circuit.

Avoided Distribution Losses is reflected as a ***benefit*** in the RCB Framework for applicable DG resources.

Integration Costs

The intermittent nature of renewable resources introduces additional volatility to the net demand on the system, which could put pressure on the inherent flexibility and balancing services of the system. Reliable operation and compliance with NERC requirements dictate that system operators balance generation and demand while maintaining adequate operating reserves. Integration costs are associated with these requirements when a system has increasing levels of renewable resources. The following operational components contribute to Integration Costs:

- <u>Generation Volatility</u>

  Generation volatility is common for renewable resources, primarily based on instantaneous weather variability. This volatility increases the overall net demand volatility to which the system must be prepared to respond, and affects the economic dispatch, ramping and regulating requirements of other generating units. The Balancing Authority sets aside a minimum of online contingency reserves (Regulating Reserves) to meet intra-hour net load intermittency and volatility. NERC requires that short-term generation fluctuations of seconds to minutes be managed by Regulating Reserves to balance system load. These fluctuations are initially managed and served by online and available resources. If online reserves are insufficient to manage the generation volatility, additional resources are needed to manage the generation gap and maintain adequate contingency reserves. Increased use of contingency reserves increases total system production costs. High levels of renewable penetration will require additional levels of Regulating Reserves which will need to be committed at certain periods of time to manage the resulting net load variations.

- Generation Ramping

  When a renewable resource is available on a diurnal cycle, renewable generation has an impact on the ramping requirement of the fleet. Normal weather patterns create these ramping requirements, which vary across the year. Other generation resources are required to mitigate generation volatility and uncertainty as the amount of VERs increases. Renewable resources can affect both the magnitude and the duration of the ramping requirement. Outside of the 10-minute window, renewable resources directly affect operating reserves, which manage system load and generation variations that last more than 10 minutes. Increases in the system ramping requirement can affect the amount and type of operating reserves needed. These impacts have the potential to increase the total system operating costs.

- Generation Forecast Error

  Renewable resources have a degree of inherent uncertainty due to dependence on weather and limited dispatchability. An accurate renewable generation forecast is required to reliably and economically commit and dispatch the fleet, a level of forecast error is expected due to resource uncertainty. System operators must contend with this uncertainty as they make commitment and dispatch decisions, which introduces inefficiencies to overall system operations. The inefficiencies associated with imperfect forecasts have the potential to increase the total system operating costs. High levels of renewable penetration could require increased system flexibility to manage the generation uncertainty.

Integration Costs are reflected as a ***cost*** in the RCB Framework.

SECTION 5 RENEWABLE COST-BENEFIT METHODOLOGY

Avoided Energy Costs

Renewable resource Avoided Energy Costs can be calculated by multiplying the hourly renewable generation profile (in MW) by the appropriate System Avoided Cost (in $/MWH) for that same hour. The annual sum of this product represents the annual avoided energy cost.

This sum is divided by the renewable generation (in MWH) to give a single annual avoided energy cost (in $/MWH). This calculation can be performed for each year of the resource life. The equation for this calculation is:

$$\textit{Avoided Energy Cost}_j = \left[\sum_{i=1}^{8760} RGP(i,j)\ x\ SAC(i,j)\right] / \sum_{i=1}^{8760} RGP(i,j)$$

Where:

Avoided Energy Cost$_j$ = the avoided energy cost in year *j (measured in $/MWH);*

Renewable Generation Profile(i,j) = the renewable hourly generation profile for hour *i* in year *j (measured in MWH)*; and

System Avoided Cost(i,j) = the System Avoided Cost for hour *i* in year *j (measured in $/MWH).*

Renewable resource Avoided Energy Costs can also be derived directly from a production cost model. The system can be simulated in the model both without the renewable resource and with the renewable resource. The reduction in system production cost between the two simulations represents the Avoided Energy Costs of the resource. This value can be divided by the renewable resource generation (in MWh) to produce a $/MWh value.

Deferred Generation Capacity Costs

Deferred Generation Capacity Costs are a function of the renewable resources contribution to system reliability. Assessing a resource contribution to reliability requires the determination of an Incremental Capacity Equivalence (ICE) or an Effective Load Carrying Capability (ELCC). The ICE (in MW) is calculated by multiplying the hourly CWFT by the renewable hourly generation profile. This product is then summed by hour across the year. The ELCC (in MW) must be derived in a system-reliability planning and production cost model. The capacity equivalence measurement (in MW) is then multiplied by the value of generation capacity deferred, which includes FOM impacts, to calculate the annual total deferred generation capacity benefit. The formulas for the above calculations are:

$$\textit{Deferred Capacity Cost}_j = \textit{Capacity Value}_j \ x\ \textit{Capacity Equivalence}_j$$

Where:

Deferred Capacity Cost$_j$ = Deferred Capacity Costs in year *j (measured in $);*

Capacity Value$_j$ = value of deferred generation capacity in year *j* (measured in $/kW); and

Capacity Equivalence$_j$ = capacity equivalence in year j as defined by either the ICE or ELCC of the resource.

$$\textit{Incremental Capacity Equivalence}_j = \sum_{i=1}^{8760} CWFT(i)\ x\ RGP(i,j)$$

Where:

CWFT (i) = the capacity worth factor for an hour *i* in any given year (measured in %); and

Renewable Generation Profile(i,j) = the renewable generation profile in an hour *i* of year *j (measured in kW).*

And:

ELCC = Effective Load Carrying Capability as determined by a system-reliability model

Deferred Transmission Investment

The size and various locations of DG should be evaluated in a system-wide study based on assumed future DG levels. The deferred transmission investment benefits associated with the addition of DG are determined by evaluating two alternative future system scenarios, one with and one without additional DG. The transmission investments and in-service timing of projects are determined for each scenario's study horizon. The DG analysis is performed based on traditional transmission expansion planning, focusing on how DG impacts the required in-service date of any identified projects.

The starting point year for the study is based on the last known year of state commission-approved resource decisions for load-serving purposes. Future generation to serve future load growth over the longer-term study period is not determined, so the location and size of any future generation is speculative and uncertain. The study is modeled as proxy generator injections into the 500 kV network, in order to avoid impact on the location of transmission by the assumed placement of new generation. The metropolitan areas of Atlanta and Birmingham are excluded from the new proxy generation additions to simulate power delivery into these major load centers over the bulk transmission network.

For purposes of performing the analysis to determine the increase in power flows on transmission facilities from load growth, the power flow model is used to scale the system load in the transmission planning cases by 200 MW for each year of projected load growth. This load scale is performed on a pro-rata basis for the load located at each existing system load bus.

$$\Delta load_n = \frac{load_n}{load_{total}} \times 200\ MW$$

This process is repeated for each year in the 20-year study timeframe until the system load has been scaled by a total of 4,000 MW. The load at each bus is scaled using an assumption that the power factor (pf) of the load does not change as it is scaled.

To determine the transmission projects necessary to support 20 years of load growth, the Managing and Utilizing System Transmission ("MUST") power flow transfer analysis tool is used on the created cases. MUST simultaneously scales up the proxy generation and forecast load, simulating serving load growth from the proxy generation. The single transmission line (i.e., N-1) contingency analysis performed by MUST is used to determine the MW transfer level at which a given transmission facility becomes overloaded. A series of approximately 60 more cases are created with individual existing units modeled offline to create generation contingency (i.e., N-G) system models. A similar MUST analysis is run, resulting in a single transmission line plus generator contingency (i.e., N-G-1) analysis matching the typical transmission planning expansion criteria. The most limiting system loading from the N-1 and N-G-1 cases are reviewed to determine the need for transmission expansion projects. Each thermal constraint identified by the MUST analysis process is then evaluated on a case-by-case basis to determine the transmission project needed to alleviate the constraint. The cost of each identified project is determined using planning level cost estimates. The timing of those projects is determined based on the MW transfer level identified for the constraint. The identified MW transfer level is divided by 200 MW load growth per year to determine the expected year of construction for identified projects.

This process is performed with and without the DG to determine DG impact on the expected timing of the projects. This resulting difference in transmission project timing to serve load over the 20-year study period is evaluated in an economic analysis that results in a benefit attributed to DG.

Avoided Distribution Energy Losses

Calculation of Avoided Distribution Energy Losses associated with the addition of DG is the same as Avoided Energy Costs and Deferred Capacity Costs, except the calculation is applied only to the distribution loss profile. Using the same model as Avoided Energy Costs and Deferred Capacity Costs, the 8,760-hour (8,784 for leap year) distribution loss profile is applied to the system avoided energy costs and CWFT (see those sections for detailed formulas). The distribution loss profile is developed by multiplying the distribution profile by system-weighted distribution loss factors, including components for transmission substation losses, sub-transmission losses, and distribution system losses. Alternatively, the DG profile can be grossed up by the amount of distribution losses. In this case, the Avoided Distribution Energy Losses benefit is incorporated into the calculation of Avoided Energy Costs and of Deferred Generation Capacity Costs.

Integration Costs

A reliability-based renewable integration study is conducted to determine expected system integration costs. The study considers system operation and costs at various levels of renewable penetration, and uses a production cost model with these capabilities:

- Sub-hourly system dispatch.
- Sub-hourly load volatility.
- Sub-hourly renewable resource volatility.
- Sub-hourly reliability determination.
- Weather variability

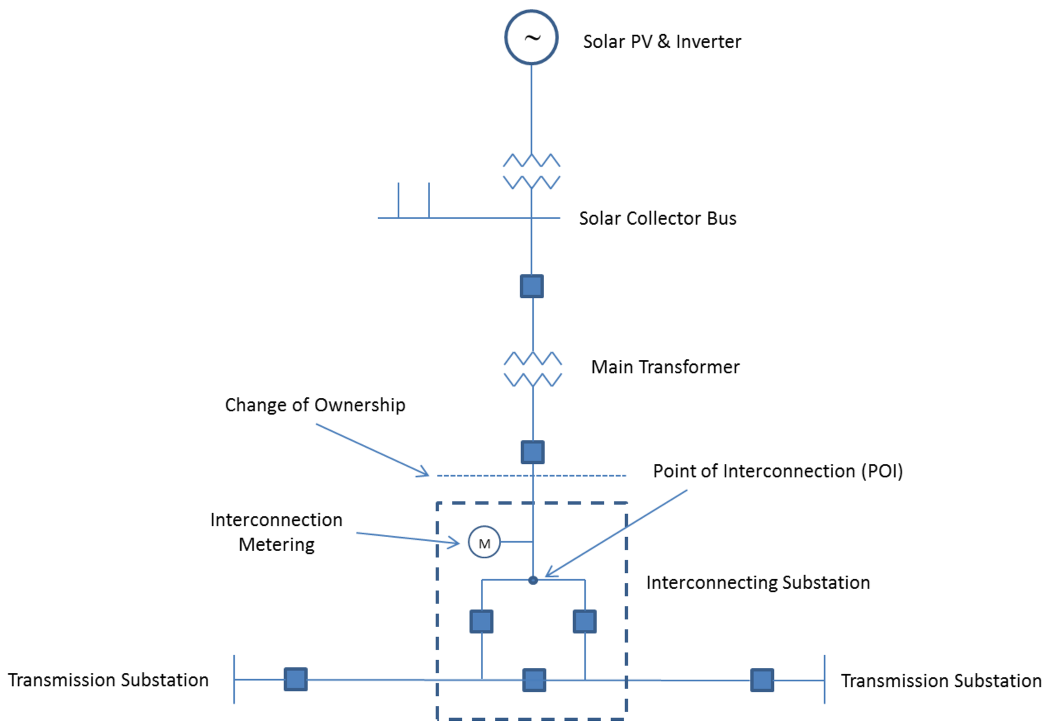
A stochastic production cost model is used to simulate sub-hourly real-time interactions and allocate hourly resources for operating reserves to manage hourly weather-driven variations. The system is first simulated without renewable resources to establish a reliability baseline. The study then determines the sub-hourly reliability impacts of adding renewable resources and identifies the costs to mitigate those impacts. The reliability impacts represent the inability to routinely balance load on a defined time interval (e.g., 5 minutes). Mitigation techniques include increased load-following reserves or operating reserves and the introduction of additional flexible resources to the system. The study isolated sub-hourly reliability impacts from the resource adequacy of the system by maintaining a consistent Loss of Load Expectation (“LOLE”) across all simulations. The identified mitigation costs are divided by the renewable generation to develop in Integration Cost in $/MWh.

The methodology allows for the Integration Study to be completed by Southern Company personnel or contracted to an established industry consultant and allows for different renewable technologies to be studied independently to determine technology-specific Integration Costs.

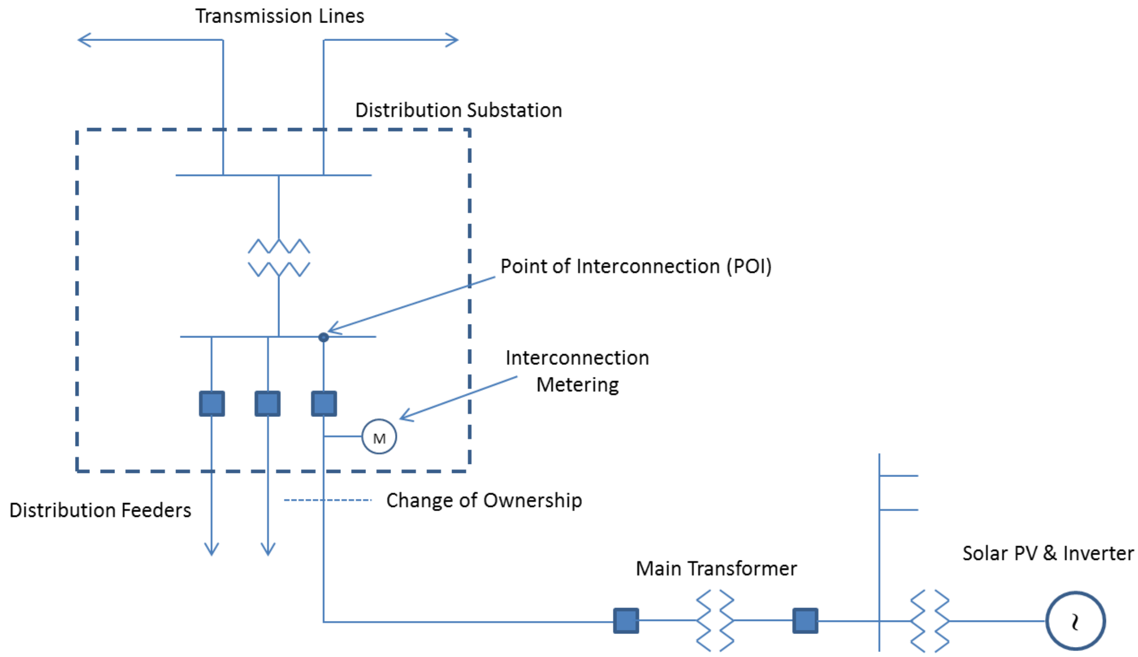
APPENDIX A – REFERENCE CONNECTIONS

The various connection types shown are for illustrative purposes only. For Utility Scale – Transmission (US-T), Utility Scale – Distribution (US-D), and Distributed – Greenfield (“DG-G”), the exact interconnection configuration will be determined by the respective Operating Company.

Utility Scale – Transmission (US-T)



Utility Scale – Distribution (US-D)



Distributed – Behind the Meter (DG-BTM)