NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Technical Report

## Inter-Entity Short-Circuit Model

July 2022

**RELIABILITY | RESILIENCE | SECURITY**




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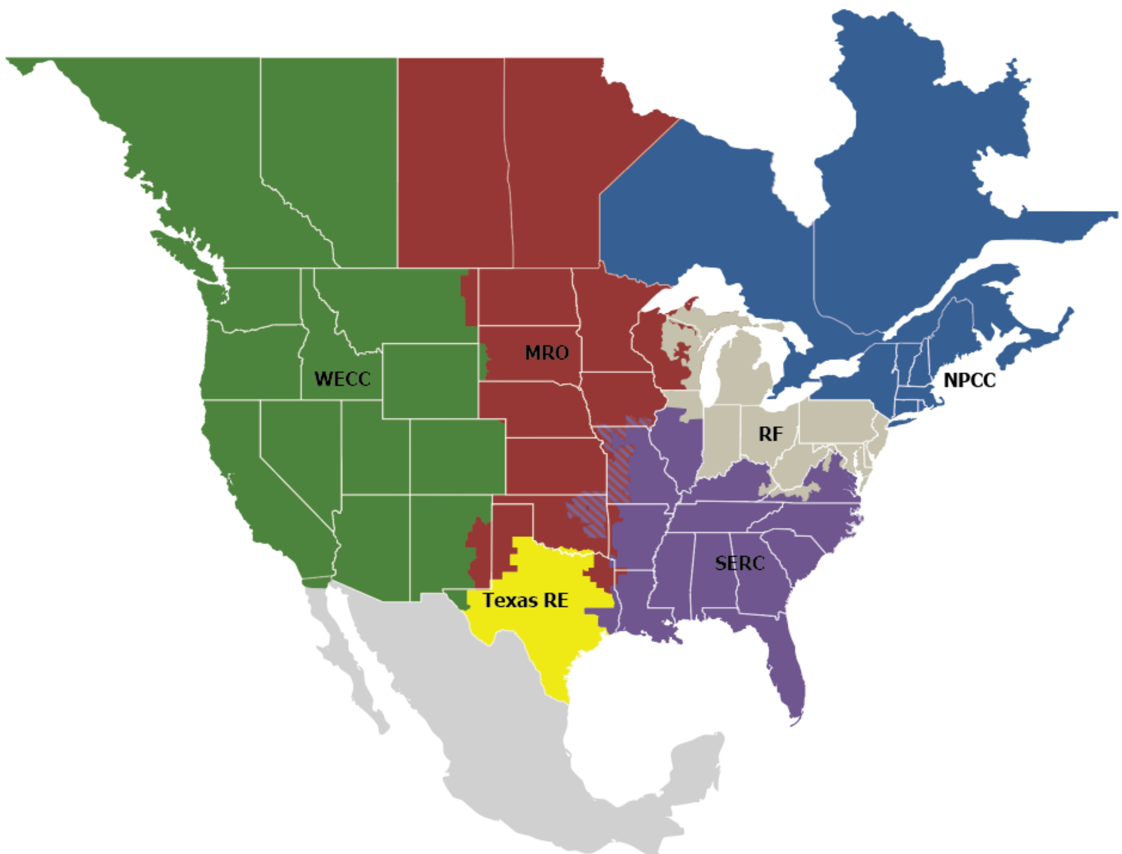
# Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

*Because nearly 400 million citizens in North America are counting on us*

The North American BPS is made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

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| **MRO** | Midwest Reliability Organization |
| **NPCC** | Northeast Power Coordinating Council |
| **RF** | ReliabilityFirst |
| **SERC** | SERC Reliability Corporation |
| **Texas RE** | Texas Reliability Entity |
| **WECC** | WECC |

# Executive Summary

Reliable operation of the power system requires accurate short-circuit models to predict fault currents used by protection engineers in the development of protection system settings. Updating model data internal to an entity is normally performed as part of new projects but updating model data at boundaries connecting to other entities (inter-entity updates) is more challenging. The increasing amount of Inverter Base Resources (IBR) requires updates at a rapid pace.

Best practices for Inter-entity updates include an annual review of the external system model, or more frequently if notified of a major change in the neighboring system. The decision to incorporate external changes should follow a risk-based process and consider the extent of the changes and their impact to the model. Network equivalents of neighboring systems should typically be located 2-3 buses into the neighboring system from the boundary bus. Correlation of the two models including short circuit parameter settings, bus and line formatting, and numbering and labeling should be completed pre-conversion. Quality assurance checks post update for normal and N-1 system conditions include comparison of fault values and X/R ratios. All four fault types (three-line-to-ground, single line to ground, line-line, and two-line-to-ground) should be considered.

Recommendations to improve the accuracy related to updating inter-entity short circuit models include providing short-circuit models in a format compatible with industry accepted software. If created by converting a power flow model, the converted model should be fully validated and corrected prior to publishing.  There are conversion errors between industry software, boundary equivalents may no longer be appropriate for creating equivalents that include IBR, and additional operating conditions may be of significance.

This report provides technical details on methods and challenges in updating inter-entity models and possible ways to validate an updated model prior to publishing for use.

# Introduction

Short-circuit studies form the basis for the development of protection system settings by providing necessary fault currents used by protection engineers. When performing protection system setting development, the short-circuit model should be accurate and up to date to the greatest practical extent. Short-circuit models are like power flow models; they both represent impedances utilized in analyzing grid flow of electric power in an interconnected system, and the same model is sometimes utilized for both short-circuit and power flow purposes. However, transformer connections, sub-transient synchronous generator impedances, and zero sequence data are of the utmost importance for accurate short-circuit models while also having a lower effect on power flow study results. With the increasing IBR influx and associated retirement of traditional generation, Bulk Electric System short-circuit models are requiring updates at a rapid pace to keep up with new changes. Updating modeling data internal to an entity is normally performed as part of new projects while all data is readily available. Updating modeling data at boundaries connecting to other entities is more challenging.

## Importance of Accurate Short-Circuit Models

Safe and reliable operation of electrical power systems requires the ability to predict and simulate sources of fault current. Accurate modeling of power system facilities is essential for the appropriate selection of equipment ratings as well as the setting of protection system parameters for various operating conditions. Nonsynchronous powered generating resources and synchronous generation are sources of fault current and should be considered in short-circuit calculations.

Power system models form the foundation of calculating operating limits, performing event analysis, developing protection systems settings, performing protection system coordination and planning studies, and completing performance assessments. A primary aspect of power systems analysis is accurate modeling of the quantity of components that form complex interconnected systems within operational planning, short- and long-term planning, and protection models. The accuracy of power system models is vital to determine protection device settings. Inaccuracies in power system models can lead to misoperations caused by inaccurate protection device settings that often directly result in loss of load.

## Load Flow vs. Short-Circuit Models

In a balanced three-phase system, the currents flowing in the three phases under normal operating conditions constitute a symmetrical positive-sequence set. Cases that include sequence network parameter data can be used to calculate the current flow paths of each phase of the system. These positive-sequence currents cause voltage drops of the same sequence only. Individual sequence (positive, negative, and zero) circuit characteristics are essential for obtaining the values of the sequence impedances of elements of a power system to construct the sequence networks for unbalanced fault calculations. The neutral points of a symmetrical three-phase system are at the same potential when balanced three-phase currents are flowing.

Historically, power system planners have utilized modeling software with positive sequence data to predict balanced load flow. Such programs normally have the capability to include information for unbalanced systems; however, unlike power flow calculations, correct modeling of negative and zero sequence data as well as correct transformer connections are critical for accurate short-circuit data.

## Network Equivalent of Inter-Entity Modeling

Short-circuit models are representations of an electrical power system and designed to accurately provide short-circuit data at any point internal to its boundary. These boundaries are often chosen to be a NERC Regional Entity, or an individual Transmission Owner's system. For accurate short-circuit data, the boundary of one model must be properly woven together with the boundary of all adjoining models as short-circuit current will flow between them.

Creating a network equivalent requires engineering judgment concerning the size, accuracy, and complexity of the neighboring system. To create an equivalent network is to replace a portion of the network with an equivalent circuit that contains boundary buses with equivalent lines, generators, loads, and shunts from the external system that has been eliminated. The equivalent circuit is created such that the current-voltage relationship at the load of the original network is unchanged, so the fault current at the boundary buses between the two systems should remain unchanged.[1]

[1] "Short-Circuit Modeling and System Strength" NERC White Paper, February 2018

# Chapter 1: Methods

Modification to components that impact the network's topology (e.g., lines, transformers, breakers) or its generation resources that supply the network will impact short-circuit values. The NERC MOD Reliability Standards establish consistent modeling data requirements and reporting procedures for these model updates. However, when updating a short-circuit model in the network, two or more models are woven together to obtain updated short-circuit values internal and external to the combined model. This chapter details considerations and methods used to update inter-entity models.

## Considerations

When protection system settings are developed or a protection system coordination study is performed, a model of the protected element and short-circuit sources in the vicinity should be accurate and up to date. The severity of model change, number of buses away the change has occurred, and margins within the relay settings determine the timing of updating inter-entity short-circuit models. Model updates internal to an entity should be performed as topology and element changes are made in conjunction with new construction projects and new calculated protective relay settings. For coordination verification, specifically those within two to three buses from the boundaries or tie lines, inter-entity model updates should be completed within the six-year period at a minimum set forth in PRC-027. As a best practice, these updates should be revisited annually or more frequently if notified of a major change in a neighboring system.

An annual update of boundary equivalents coincides with most regional transmission organizations' (RTO) practices for providing network equivalents. The network equivalent updates are based on a current year and a future model. The future model may be two to five years out; however, this may vary among RTOs. The benefit of providing a network equivalent for a future short-circuit model is that it allows the receiving entity to prepare for any significant changes occurring in close vicinity of the network boundary.

When creating a network equivalent, the fault current at the boundary buses should remain unchanged. Partitioning an equivalent network from its neighboring study area requires analyzing up to three buses away from the study bus for sufficient accuracy.[2] By comparing fault values at the interconnection point(s) between the models, this accuracy can be validated. PRC-027 allows triggering of protection system coordination studies when the fault current changes by 15%. Protective relaying inherently utilizes margins when set points are selected to account for errors in current transformers, transmission line parameters and spacing, relay error, etc. A small amount of error in the short-circuit model is not critical nor uncommon when comparing fault values at interconnection points; however, should these variances approach values used for relaying margins or coordination triggers they become intolerable and could lead to misoperations.

## Max and Min

Most short-circuit models are configured for system peak conditions (i.e., all generating resources), including contingency reserves are considered online. The same is carried over to network equivalents. Typically, a network equivalent includes two real buses only as the rest of the network is reduced to an equivalent. An entity receiving the network equivalent would have to detach the existing network equivalent in the model and replace it with the updated equivalent.

Balanced and unbalanced faults are calculated from the source impedances of the connected grid resources that feed into system impedances. When grid resources are primarily composed of synchronous machines, maximum short-circuit fault currents are usually derived by utilization of the sub-transient reactance values. Minimum fault currents

[2] "Short-Circuit Modeling and System Strength" NERC White Paper, February 2018

are commonly derived by removal of generation and/or lines to determine an n-1 or greater contingency in the vicinity of the faulted location.

With the influx of IBRs, maximum and minimum fault values become dependent upon voltage since these devices are both voltage controlled current sources and the inverter's control strategy. For maximum fault values, the IBR should be correctly modeled in the system to vary its contribution based on the voltage of the interconnected system. Simply utilizing a driving source impedance or boundary equivalent may not be an accurate representation. Minimum fault cases become more complex.

The network equivalent for off-peak (valley, spring, fall) load level is typically not shared. However, this may be of importance in the future with increased IBR penetrations. As IBR penetrations increase, it is expected that short-circuit levels across the network will decrease. As such, it may be necessary to study off-peak load levels to verify that reliable, secure, and dependable protection is maintained. However, if such a scenario is studied with network equivalents of neighboring utilities based on peak condition, then the results (especially near the boundary buses) may be skewed enough where may not be considered reliable. Entities with significant IBR penetrations may want to consider sharing network equivalent for off-peak condition.

The IBRs are represented as voltage controlled current sources in the short-circuit model. The traditional short-circuit programs do not account for IBRs when reducing a network to develop an equivalent. There is a need to develop a methodology to represent voltage controlled current sources in the network equivalent. This is further explained with the example found in **Appendix A**. One alternative is to adopt the entire model. As a clarification the intent is to include the transmission network and generation resources in the entire model; however, not to necessarily include the distribution network, tapped distribution banks, etc.

## Adopt Entire Model

The simplest method to update short-circuit models is to adopt complete models around and including the entity's system that have already been updated. This is obviously not an option for larger networks but may be a viable option for a single entity. For example, an RTO may issue a short-circuit model each year that has updated equivalents from all members and external sources. Adopting the entire model would allow the entity the flexibility to modify generation mix as appropriate both internal and external to their system. As discussed further in **Chapter 2**, such a model should be vetted by the entity prior to use. Of specific model accuracy concern is a short-circuit case that has been created via a software conversion. This creates the possibility that the updated model could contain conversion errors. Additionally, topology like normal open ties between generator buses should be verified. If the entire model is reduced for ease of use by an entity, then the network equivalent should contain equivalents for a minimum of three buses away from the short-circuit bus under investigation.[3]

## Keep Entity Model and Update External Ties

Another option is to develop an internal model of interest and then integrate external models so that the resulting model simulation accurately portrays element currents and bus voltages as if the entire model was represented. This is often the case when there is no Regional Entity that develops a full Interconnection-wide model. An entity may also want to have a more detailed and up-to-date model than what is presented for an Interconnection-wide model and will develop its own model from a system-wide model. The following are a couple of options and methodologies for developing those types of models.

[3] "Short-Circuit Modeling and System Strength" NERC White Paper, February 2018

## Merge Internal with Entire External Model

When an Interconnection or system-wide model is available but an individual entity wants to include a more detailed model of its system, the entity can cut its system out of the detailed model and replace it with its full model. The entity would determine which external buses are directly interconnected to its system and then delete all elements that connect from those buses to its system. Then the entity would delete all the remaining buses from the model.

The next step would be to remove any external ties to the external buses in the entity's preferred model and paste that model into the Interconnection-wide model and merge the interconnecting buses together.

## Update Boundary Equivalents at External Tie Points

When an Interconnection-wide model is not available, an entity will need to coordinate with its neighboring entities and request the other entity's fault study model as well as share its internal model. The different models can then be spliced together, and boundary equivalents can be determined at some appropriate level of detail (i.e., at some number of buses back from the entity's interconnecting buses and element). Some geographic areas might develop a regional fault study model using this approach.

# Chapter 2: Challenges

Maintaining accurate inter-entity short-circuit models can be challenging both technically and logistically. The following are some of the common challenges that entities face when consolidating inter-entity short-circuit models. These challenges should be considered both when preparing to consolidate and when troubleshooting issues with model comparisons or validations.

## Pre-conversion Mapping

Perhaps the most challenging aspect of inter-entity short-circuit model consolidation is the pre-conversion mapping. Entities must be able to correlate components in one model to their counterparts in the other model. Logistically, this requires agreement between entities on naming or numbering conventions. In cases where only a few interconnections exist, a user might be able to determine the matching components without an exact match between component naming or numbering. However, if automation is being used for the consolidation of models, it is likely that the identifiers will have to match exactly. If models have already been established with names or numbers that are not common between the two models, then the process of manually renaming the components is both time consuming and tedious.

### Format Variances

Whether entities are using identical software or entirely different software, it is likely that the model format will have differences that must be considered. Due to differing company philosophies, they may use different per-unit bases, different transformer modeling techniques or connection codes, or different methods of modeling elements and buses. For example, some entities may assume uniform conductors for transmission lines while others may use tapped buses to distinguish changes in conductor type or spacing. Some entities may model all buses as straight buses for simplicity while others may model the exact configuration (e.g., ring buses, breaker-and-a-half, main-transfer schemes). It is highly likely that relays are modeled differently. Entities may also choose different options for the fault simulations and relay solutions that might impact comparisons during validation (see **Chapter 3** for more information).

### Power Flow to Short-Circuit

In some instances, there may be a need to merge data between short-circuit models and long-term planning or power flow models. This presents several unique challenges.

The first challenge is correlation of the data. Data must be correlated between the two models with a common labeling or naming convention. This is necessary to know when data extracted from one model belongs in the other model.

Once the components are correlated between the two model types, the second challenge becomes extraction of data. It is unlikely that the two software solutions support direct conversion between short-circuit and long-term planning or power flow models. Fortunately, most software solutions offer an application programming interface (API), which allows easier extraction of data; however, use of the API requires moderate knowledge of computer programming that protection engineers might not have.

The third challenge is the conversion of data. One must understand the data structure of both models to allow for data exported from one software to be imported into another. More than likely, the parameters are not identical between the two models. The primary key (unique identifier of components) might not match or have the same name, or impedances could be expressed in different units or be modeled entirely differently ("T" model impedances vs. short-circuit impedances). This step is more easily achieved with spreadsheets, databases, or similar tools that assist with visualization and transformation of data.

The final challenge is importing data into the final model that may require the use of a different API for the software into which the data is being imported.

### Short-Circuit to Short-Circuit

In most cases, short-circuit software solutions offer a means of converting network models for use in other short-circuit software solutions. This gives different entities the ability to collaborate despite utilizing different tools. The two models sometimes offer mathematically equivalent solutions; however, there are other aspects of the model that often do not translate identically. For instance, the physical topology of the model may not convert, meaning that the converted model could be difficult to interpret visually. Additionally, the relay models and associated settings will most likely not be included in the conversion, so an exchange of relay settings may also be necessary in addition to the models. Lastly, the conversion might model certain elements or branches differently than the source model. For example, a single 3-winding transformer might convert to two 2-winding transformers in series. Infinite impedances in one model (such as zero sequence impedances through the delta of a transformer) might convert to a shunt reactor or neutral impedance of value 99999. Vendor software may take third-party models and convert them to another format such as a ".dxt" file and then input that format back into their software.

### Version to Version of Same Software

If entities are using different versions of the same software, this can add additional complexity to the consolidation of the models. It is likely that the entity with the newer version will have no trouble importing the older model version because the software versions are likely backwards compatible. The entity with the older version might not be able to interact with or import the newer version at all. If they are able, they should consider the following factors:

- What new features or bug fixes have been added in the newer version?
- Is it worth an upgrade to the newer version to fix bugs or add additional features?
- If not, does the neighboring entity's model contain any of the newer features? If so, what is the impact of them not being included when their model is converted to the older version?

Fortunately, the mathematics behind the short-circuit calculations is fundamentally unchanged in many cases. New features often involve the user interface or graphical representation, meaning that the accuracy between model versions is often unaffected. This also means that in some cases versions are even forward compatible. A useful conversion check may be to take a vendor's model, convert it using their tool, and reading it back into their software.

## Bus and Line Common Format

There needs to be some consistency in line and bus format to create inter-entity network equivalents. Connection points between entities need to be consistent in what is shown, and they must be able to be mapped between the entities with some identifying characteristic. Typically bus names or bus numbers are used. For lines modeled to the border buses, it is important to ensure line impedances do not get duplicated.

One of the options in the methods discussed above is to adopt the entire model of a neighboring entity. If this is done, bus naming and/or numbering must be unique so that the short-circuit program can identify different data points. If the adoption of an entire model is used for a Regional Entity with multiple entities, it may be helpful to standardize bus naming, numbering, and having an identifying tag to denote ownership. This standardization may be a significant change when first merging with the entire model of a neighboring utility.

## Duplication of Model Parameters

When simplifying interconnections using Thévenin equivalent calculations, it is important to consider multiple network paths that may exist between boundary terminals. For instance, consider Entity 1, which owns Substation A, and Entity 2, which owns Substations B and C, as depicted in **Figure 2.1**. If Entity 1 wishes to model the Thévenin equivalent of the tie line to B, they must account for the connection between B and C. In this simplified scenario, an accurate Thévenin equivalent at B and C requires taking not only the lines from A to B and A to C out of service to avoid inclusion of Entity 1's own system but also the line between B and C. After determining the separate Thévenin equivalent parameters for B and C, the lines should be placed back in service and remain in the simplified model. If the lines are not removed when performing the calculation, the Thévenin equivalent calculation at the tie line to B will include both C and A, and the Thévenin equivalent at C will include B and A. The impact of the errors varies depending on the relative contributions from each equivalent circuit. The errors quickly diminish for network connections that are further electrically from the interconnections being modeled. For instance, a connection between B and C that exists three or four buses away may have little or no impact on the Thévenin equivalent calculations between the two entities. Entities must balance the need for accuracy of the model with their desire for simplicity when determining which network paths should be modeled and which can be ignored.

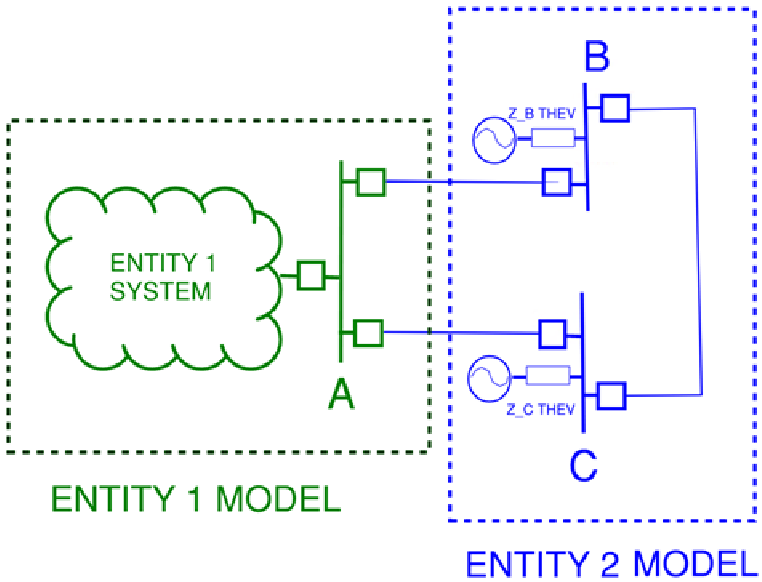


**Figure 2.1: Two Entity Simplified Model**

## Mutual Impedance

Another challenge to consolidating short-circuit models is the inclusion of mutual impedances. Entities may have different philosophies regarding when mutual coupling needs to be modeled and when it can be disregarded. Additionally, the mutual coupling itself might be modeled differently. For instance, the starting and ending terminals of the paired lines may not have matching identifiers between the two models. The starting and ending terminals might also be reversed for one or both paired lines, resulting in different mutual impedances. The polarity of the mutual coupling can be easily verified by performing the following steps:

1. Simulate a fault on one of the lines in the mutual coupling pair.
2. Determine the direction of current flow on the unfaulted line of the pair.
3. Verify the apparent impedance as seen from each terminal of the faulted line both with the unfaulted line in service and out of service:
    a. For opposing current flow, the apparent impedance should decrease with the mutually coupled line in service
    b. For current flow in the same direction, the apparent impedance should increase with the mutually coupled line in service.

In **Figure 2.2**, the entity should expect the apparent impedance to the fault as seen from Terminal B to be less when Line B–C is in service.

If entities wish to consolidate the collapsed Thévenin equivalent models, mutual coupling can be problematic because tie lines may be mutually coupled with lines solely in the neighboring entity's system. Depending on the strength of the sources and the amount of coupling, the entity may need to model the additional neighboring entity's mutually coupled lines. This portion of the neighbor's system can be simplified if necessary by collapsing one or both ends of the (non-tie) coupled line using the Thévenin equivalent as an example. In many cases, this can only be done with one end of the line because the other end often terminates at the same station as the tie line (see **Figure 2.2**). Again, entities must balance accuracy and simplicity when determining which mutual coupling pairs should be modeled.

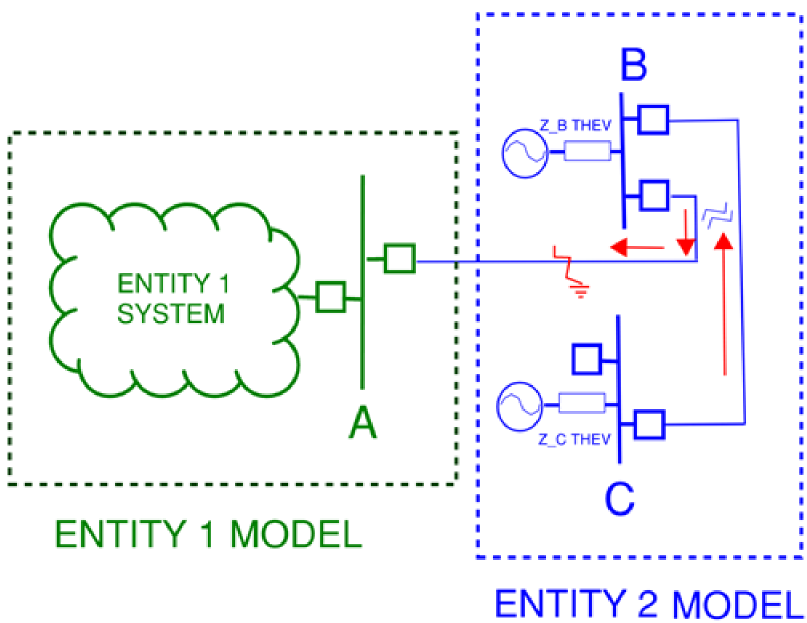


**Figure 2.2: Two Entity Model Example**

## Inverter-Based Resources

Previously, the number of IBRs connected to the grid was very small, and their effects could be ignored, but this is no longer the case. As more IBRs are connected to the grid, there are challenges both with modeling them and with simplifying cases to equivalents.

The method for modeling IBRs discussed above is modeling a voltage controlled current source. To solve a short-circuit case that includes IBRs, the software uses an iterative process for solution: it solves to find the voltage at the terminals of the IBR, uses that voltage to generate the expected current, solves to find the voltage at the terminals of the IBR using that current value, and iterates until the solution converges. Since the existing method for modeling IBRs includes this iterative process, and IBRs have a variety of parameters, it is not possible to accurately fold multiple IBRs into a Thévenin equivalent. It should be noted that IBR units (e.g., PV inverters, Wind Turbine Generators) at one facility with similar characteristics can be aggregated, reducing the number of IBRs modeled; however, this does not solve the issue with creating an equivalent.

As modeling IBRs is a recent development, available modeling software varies in the parameters used to model, and different entities may use different methods of modeling. The challenges discussed in the conversion portion of this section apply to IBRs too.

As more IBRs are added to the model, there is a software challenge: each IBR adds more complexity and more iterations to each solution, requiring more processing power. If a complete model is used, including the IBRs of all neighboring entities, the processing performance of the software used may be reduced to the point of failure. One possible solution to this problem is to alter the modeling software to limit the number of IBR terminals modeled in the area being studied; IBRs where voltage is not expected to be impacted due to a fault being studied could be assumed fixed current sources. Further work by software vendors and power engineers will be required to adequately address this challenge.

## Change Management

There are many small entities that do not have or maintain their own short-circuit models. Small municipalities and Generator Owners are some examples. For an entity that maintains a model connecting to one that does not, it is a challenging task to ensure the data for these entities is accurate and up to date. If there are changes, the non-modeling entity may not have the resources in place to send an accurate update. For non-modeling entities that connect to multiple modeling entities, there is an additional challenge: which of the modeling entities is responsible for including the non-modeling entity's data into their model. There will be redundancy in equivalent circuits if more than one of them do. If a model of an entire area is adopted, there will be challenges in ensuring the non-modeling entity's system is fully represented, not just an equivalent.

# Chapter 3: Data Validation (Post Update)

Once a model has been updated, it should be vetted prior to use. Errors could have occurred in the process regardless of the methods used for the update. This is extremely important for organizations or RTOs that publish updated short-circuit cases for multiple users. Short-circuit sequence data should be validated, including characteristics of generators, transmission lines, and transformers. Updated data should be reviewed, values should be measured against a benchmark, and common characteristics between the old and new case should be compared when possible. Criteria like total fault current at boundary buses; number of lines and impedances; generating resources available; number of generators; total MVA of generation; and transformer type, configuration, and impedances can be evaluated.[4]

## Comparison of Fault Values

One of the most common methods of proving model data validity is through the comparison of fault values. With the challenges of pre-conversion mapping addressed and an understanding of how the network topology is modeled, short-circuit studies can be performed, and the results can be compared between models. Historically, as the electrical system grew, it was typical that short-circuit fault values would increase over time. However, this may no longer be the case with the increased penetration of IBRs and the retirement of synchronous machines. It is important that the fault value comparisons check for any discrepancy and not just fault current increases.

Comparing short-circuit fault values to an accuracy within a margin of difference can help identify areas in the model to investigate for modelling discrepancies. Creating a few different levels of margin can help prioritize and categorize what must be reviewed. Determining margin levels for a particular organization or RTO will be a balance between total discrepancies found and resources to resolve discrepancies. For example, a few levels of margins could be as follows:

- < 5% Low (acceptable but could be investigated)
- 5–10% Medium (acceptable but should be investigated)
- 10–15% High (should be investigated)
- >15% Very High (must be investigated)

These proposed margins are based on experience with three-line-to-ground (3LG) and single-line-to-ground (SLG) bus faults. Other margins may be more appropriate for different fault types.

At a minimum, 3LG and SLG fault types should be compared. Comparing 3LG faults checks the positive-sequence network of the model while comparing SLG faults incorporates the zero-sequence network and connectivity of the model. Because most short-circuit software also outputs the remaining line-to-line (LL) and two-line-to-ground (2LG) fault types (typically in the same report as 3LG and SLG), it is a best practice to also compare LL and 2LG fault values to determine any discrepancies or anomalies in the short-circuit model.

With higher penetrations of IBRs, focus may shift towards looking at comparisons of the IBR fault contributions to confirm validity in addition to comparing the total bus fault value. The negative-sequence fault current contribution from IBRs is still a widely studied topic and dependent on the inverter control. However, as mentioned previously in the challenges section, available short-circuit software varies in the parameters used to model, and different entities may use different methods of modeling.

Another best practice would be comparing fault values for N-1 contingencies of lines and bus equipment immediately surrounding the study bus. Running these N-1 comparisons can help expose model inaccuracies that may otherwise

[4] "Short-Circuit Modeling and System Strength" NERC White Paper, February 2018

only appear as smaller discrepancies for N-0 comparisons. Efficiently comparing the N-1 results from two models is not always straightforward; however, a macro can be developed to align these values and automate their comparison.

As short-circuit models are typically used to evaluate circuit breaker short-circuit ratings and fault duty, it is also a best practice to run a comparison of X/R bus ratios. Special attention should be paid to the short-circuit model's X/R preferences and any assumed X or R values the software uses when encountering an X or R equal to zero.

## Model Comparison

Short-circuit software typically has a model comparison routine or program to build a report that describes differences between model files of the same type. This report can be helpful when only a few differences exist between models; however, the output report may become overbearing when many differences exist that may be typical for annually updated models. Additionally, if there is not an easy way to filter or compare model parameter differences from the output data, manual review is necessary to find discrepancies above a specified margin.

An alternative approach to using the software's model comparison program is to export model equipment and parameters to a spreadsheet. Parameters from two models can be compared to a margin by using formulas and/or macros within the spreadsheet. Once these checks are built, the spreadsheet can be reused in future comparisons if the output data and formatting remain consistent.

## Comparison with Actual Fault Values

Real-world fault data is what a system model is attempting to calculate. It stands to reason that validating model data through comparison to real-world fault data is useful for validating a short-circuit model. To ensure a valid comparison between a model and the real-world, the system configuration in the model must match the real-world system configuration at the time of the fault. This includes generators on-line or off-line, normally open points in the system, and any abnormal issues (e.g., lines out of service, pre-fault voltage characteristics). With matching system configurations, output parameters from the actual fault and the model can be compared to find discrepancies above a margin.

When comparing model fault values to actual fault data, it could take months or even years for an actual fault on the system to show up. It is also difficult to completely match a model to real world conditions, including location, fault impedance, and generation dispatch. For these reasons, this type of comparison is most useful for approximate rather than detailed comparisons, but it still can identify major modeling errors.

When event data following a line-to-ground fault from relays at two ends of a transmission line are available, positive, negative, and zero sequence line impedances can be calculated and used to verify that transmission line's model data. It is important to note there are several phenomena that can affect calculation results. For example, if a line is not transposed, line inconsistency, measurement errors in the current or potential transformer, small fault data (three cycles or less) resulting from fast breakers, and a low fault record sampling rate. Similarly, line impedance can be validated by using a test set in conjunction with a coupling unit that injects currents into a de-energized line and sends voltage measurements back to the test set.[5]

## Comparison with Neighboring Models/Interconnection Buses

The greatest potential for outside fault current impacts to an entity's system exists at border locations with neighboring entities, so communication of short-circuit models at these locations affects the reliability of the interconnected power system.

[5] *Validating Transmission Line Impedances Using Known Event Data*. April 2016. Revised edition, SEL, inc.

When comparing fault values with neighboring entities, it is important to understand software settings to best match short-circuit output values. Make sure that fault current settings are the same as or comparable to neighboring ones (e.g., pre-fault bus voltage and generator impedance used in the fault calculation). When using an equivalence at seam location, it is recommended to have at least three buses into the neighbor's system.

# Possible Variance Issues

After updating a short-circuit model, the validation effort may reveal inaccurate data in need of correction. This section discusses common issues created when inter-entity models are merged.

## Transformer Connections

For two-winding transformers, a grounded wye can provide a path for zero sequence, unlike a delta winding in which zero sequence current cannot pass through. Incorrect modeling of grounded wye, ungrounded wye, or delta windings and their associated impedances could be a source of modeling error. The same is true for autotransformers. In a two-winding autotransformer with a delta-connected tertiary, the tertiary provides a low impedance path for zero-sequence current and has a significant impact on ground fault currents. Correct modeling of transformer impedances in addition to the connection is necessary. When modeling a transformer, understanding is needed about how the modeling software accounts for base impedance and what equivalent model values the program is looking for.

When converting from one software platform to another, there are known transformer connections and codes that do not properly convert. Software manufactures should be consulted prior to conversion if these known issues are not understood. Should three-phase fault values look reasonable in a newly updated model near a transformer, but unbalanced faults look unreasonable, the transformer connection should be questioned and validated. Most two-winding autotransformers with a tertiary are grounded wye with a delta tertiary. Such autotransformers that have all delta windings or three-winding transformers with all delta windings are likely candidates of modeling error.

## Out-of-Tolerance Zero Sequence Impedance Values

Power flow models may lack zero sequence data since it is unnecessary for a power flow study in a balanced system. If converted to a short-circuit model, out-of-tolerance zero sequence data often results. The absence of zero sequence impedance data in short-circuit models has occurred in regional short-circuit models, resulting in questionable line-to-ground fault current results when solving the short-circuit model. In many cases zero impedance values are missing (0.00) or infinite (9999). Similarly, incorrect transformer connections that do not affect power flow models can have a significant impact on the short-circuit model.

## Generation Type

Parameters for synchronous machines should provide three different positive sequence values: sub-transient reactance (Xd''), transient reactance (Xd'), and the synchronous reactance (Xd). Since the sub-transient reactance (Xd'') values give the highest initial current value, they are generally used in system short-circuit calculations for high-speed relay applications. The negative sequence reactance of the turbine generator is typically equal to the sub-transient reactance (Xd''). The zero-sequence reactance is much less than the others, producing a phase-to-ground fault current magnitude greater than the three-phase fault current magnitude.

Type III wind farms (doubly fed induction generators) are sometimes modeled with a regulated current source. Since the fault current is typically limited to 1.2–2.0 pu of maximum MVA capacity, early models sometimes were built upon the synchronous machine model with a reactance between 0.5 and 0.9 per unit. Newer models can be more sophisticated, better representing the fault contributions. Expected positive sequence values should produce 1.2–2 times rated MVA as opposed to over 6 times rated MVA for synchronous machines. Expected negative sequence impedances should be much larger than the positive sequence. Since wind turbines are typically ungrounded, the zero-sequence impedance should be very high. These types of windfarms should produce little negative sequence fault current and negligible zero sequence.

Type IV wind farms, solar farms, and batteries (IBRs that are converter interface resources) have no direct connection to the grid except through the ac/dc–dc/ac electronic converters, so they could be designed to provide negative sequence current although they provide little negative sequence current more commonly today.

Historically, IBRs were sometimes modeled as current-limited synchronous machines; however, newer IBR modeling advancements more accurately represent IBRs. Prudent checks when validating older short-circuit models should include looking for IBR resources where the positive X’’ and negative sequence impedances are the same. This is expected for synchronous machines but not for IBRs. Additionally, the zero sequence of an IBR is expected to be very high. Lastly, fault current values are expected to be in the range of 1.2–2.0 per unit of maximum MVA. During validation, consideration should be given to not only correcting any inaccurate sequence impedances but also updating IBR modeling to newer recommendations that may be available from the software manufacture.

As the ratio of IBR/synchronous generators increases, verification of accurate IBR models becomes more crucial to system short-circuit values.

## Duplicated or Missing Model Paths/Parameters

Depending upon the method used to update the model, duplication can commonly occur at the seams between regions and seams between transmission owners (area or zone numbers). Be watchful for duplication of branches and omissions of branches. Branch impedance data changes generally do not occur year-to-year in short-circuit cases. Other checks between models include bus count, line count, and mutual impedances.

# Chapter 4: Conclusion and Recommendations

Updating short circuit models at boundaries connecting to other entities is essential for protection system coordination studies and settings. Whether the updating is performed for entities of a large geographical area or by a smaller single entity, there are challenges. Considerations such as software capabilities with boundary equivalents and generation mix is becoming increasingly important factoring in the influx of IBRs. When weaving together two models consistent labeling and formatting is needed and care must be taken to not duplicate, inadvertently change or omit model parameters. Also, there are known and possible unknown issues with software conversions. Once updated, the converted model should be fully validated and corrected prior to publishing for use.

Best practices for Inter-entity updates include the following:

- Annual review of the external system model, or more frequently if notified of a major change in the neighboring system. The decision to incorporate external changes should follow a risk-based process and consider the extent of the changes and their impact to the model.
- Network equivalents of neighboring systems should typically be located 2-3 buses into the neighboring system from the boundary bus.
- Correlation of the two models including short circuit parameter settings, bus and line formatting, and model numbering and labeling should be completed pre-conversion.
- Quality assurance checks post update for normal and N-1 system conditions include comparison of fault values and X/R ratios. All four fault types (three-line-to-ground, single line to ground, line-line, and two-line-to-ground) should be considered.

Recommendations to improve the accuracy related to updating inter-entity short circuit models include the following:

- Regional Entities, Regional Transmission Operators, and other parties that may provide short-circuit models intended for utilization in protection system relaying should provide those models in a format compatible with industry accepted short circuit software as opposed to industry power flow software.
- If creating short-circuit models by converting a power flow model, the converted model should be fully validated and corrected prior to publishing. There are many errors which can occur during conversions including out of tolerance zero sequence impedances and inaccurate power transformer connections.
- Neighboring system parameters can be difficult to obtain for model validation but necessary for fault current flows into a system within a few buses from a bus under study for protection coordination.
- Modeling of IBRs and software is evolving and requires improvement.
- Consider adopting the entire model rather than using boundary equivalents at tie lines until improvements are made in software tools for creating equivalents that include IBRs.
- Historically, boundary equivalent sharing has been for peak operating conditions used in short-circuit studies. Consider sharing additional operating conditions of significance as applicable. For example, minimum synchronous resources with peak IBR dispatch.
- An improved method for an efficient exchange of data between short-circuit software should be developed.

# Appendix A: IBR Network Reduction Example

This appendix presents an example that illustrates a need to develop a new methodology to develop network equivalents for a system consisting of IBRs.[6]

One simple and popular tool used to represent network equivalents is the Thévenin impedance. For example, the Thévenin impedance of the network at 230 kV bus #1 in **Figure A.1** is 0.23% + j 2.39%.

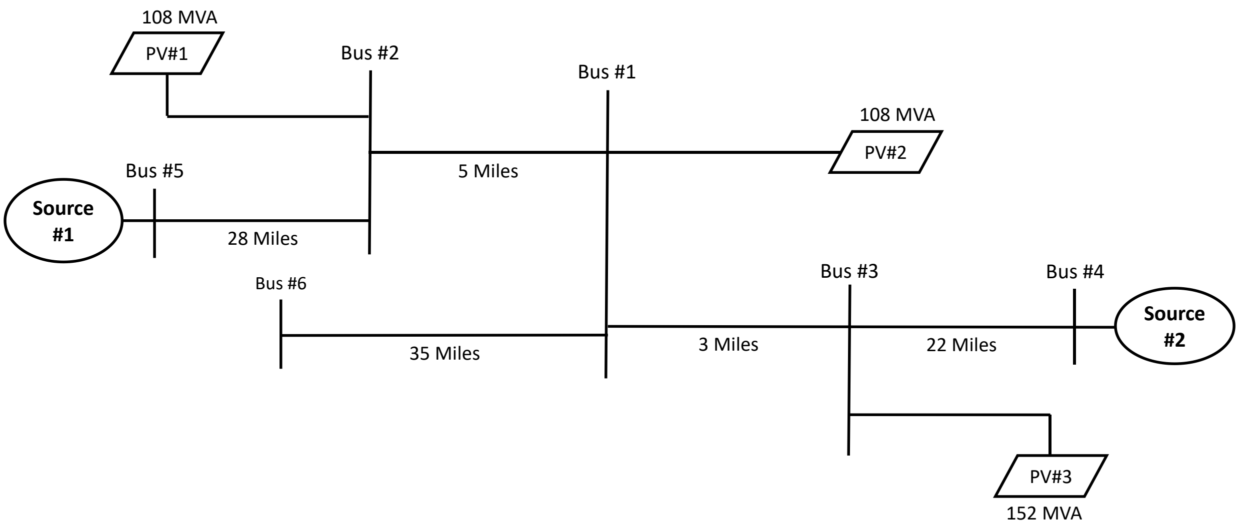


**Figure A.1: Fault Current Distribution with Photovoltaic Resources Off-Line**

One could calculate the bus #1 three-phase fault current magnitude by simply taking an inverse of the Thévenin impedance (assuming a pre-fault voltage of 100%), which is 41.7 per unit, or 10 470 A. This matches with the fault current calculated by commercial short circuit programs when the PV solar resources noted in **Figure A.1** are offline. When the nearby PV solar resources are on-line, three-phase bus fault current increases to 11 045 A (44.0 per unit). However, the Thévenin impedance calculated by the commercial short circuit program is unchanged. This is expected for networks with independent sources because the Thévenin impedance is calculated by replacing the voltage source with a short circuit and the current source with an open circuit. As such, the addition of PV solar resources (i.e., voltage controlled current sources) should not change the Thévenin impedance as these resources will be replaced with an open circuit for calculation of the Thévenin impedance anyway. However, in the presence of inverter-based resources, the network behind bus #1 cannot be represented by a pre-fault voltage source behind a Thévenin impedance.

There needs to be a way to represent the impact of PV solar resources with an equivalent. One option would be to add a current source with magnitude equal to a difference between fault current with and without PV solar resources in parallel with a voltage source behind a Thévenin impedance as shown in **Figure A.2**.

[6] M. Patel, "Opportunities for Standardizing Response, Modeling and Analysis of Inverter-Based Resources for Short Circuit Studies," in *IEEE Transactions on Power Delivery*, vol. 36, no. 4, pp. 2408–2415, Aug. 2021.

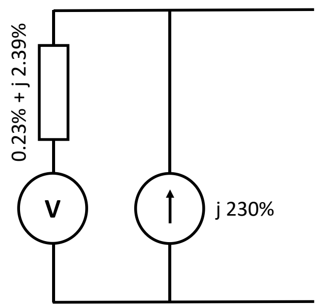


**Figure A.2: Potential Equivalent of the Network at 230 kV Bus#1**

For this example, the difference in fault current is 575 A, or 230% at 100 MVA base. However, as noted before, inverter-based resources are voltage controlled current sources. An equivalent of these resources cannot simply be a constant current source; it needs to correctly reflect dependency on voltage. Hence, the equivalent shown in **Figure A.2** is not a correct representation except in one very specific case.

Another alternative is to back-calculate either pre-fault voltage or the Thévenin impedance such that voltage divided by the Thévenin impedance equals fault current. For example, if the Thévenin impedance is unchanged, then the pre-fault voltage could be raised to $I \times Z_{TH} = 44 \times 0.024 = 1.056$ per unit. Alternatively, if it is preferred to keep the pre-fault voltage to 100%, then the Thévenin impedance could be lowered to $V/I = 1.00/44 = 0.0227$ per unit. However, none of these alternatives correctly represent the true impact of voltage controlled current sources on the network. These alternatives may be used as stopgap measures while new method(s) are developed to create equivalents with the presence of inverter-based resources is developed.

This is further illustrated with the analysis of the simple network shown in **Figure A.3**.

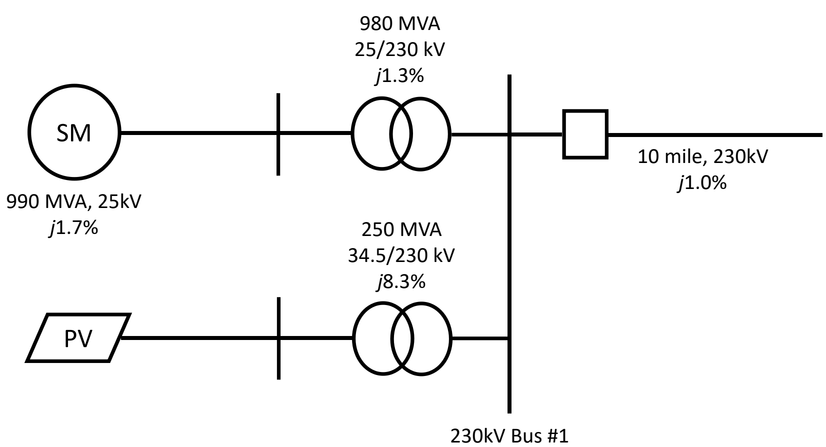


**Figure A.3: Simple Example–Synchronous Machine And Photovoltaic Resource**

The Thévenin impedance of 230 kV bus #1 is 3.0% (sum of impedance of synchronous machine and step-up transformer). For a three-phase fault on this bus, it is assumed that PV solar resource injects purely reactive current and the magnitude of this current is 753 A (300% at 100 MVA base). The total fault current is then 9120 A. One could represent the equivalent of bus #1 as shown in **Figure A.2** but with the impedance of 3% and current source magnitude of 300%. If this equivalent is used to calculate three-phase fault current at $F_1$, then the contribution from a current source would still be 300% and purely reactive. However, the reactive current contribution from the PV resource for a fault at $F_1$ is only 580 A in reality. A similar issue arises if the pre-fault voltage or Thévenin impedance is back calculated with a fault current at the 230 kV bus. For example, a three-phase fault current at the 230 kV bus is 9120 A, or 36.3 per unit. If one chooses to represent an equivalent with a back-calculated pre-fault voltage, then magnitude must equal to $I \times Z_{TH}$ = 36.3×0.03 = 1.09 per unit. In this case, equivalent at the 230 kV bus is then a voltage source with a magnitude of 109% behind an impedance of 3%. Per this equivalent, the three-phase fault current at $F_1$ is then 6840 A, which is slightly higher than the actual fault current of 6712 A. If one chooses to back-calculate the Thévenin impedance, then magnitude must be set equal to V/I = (1.0/36.3) = 0.0275 per unit. Using this equivalent, the three-phase fault current at $F_1$ is 6693 A compared to the actual fault current of 6712 A. The resulting mismatch in the magnitude of fault current is not much; however, this example clearly illustrates that the presence of inverter-based resources offers a challenge in representing the network with an equivalent that was simply achieved by using the Thévenin impedance in synchronous machine dominated networks. The complexity increases when the network with high penetration of inverter-based resources needs to be represented with a two-bus-deep equivalent network. It may be that IBRs being voltage controlled current sources cannot be correctly represented with equivalent; at a minimum, this warrants further research.

# Appendix B: Contributors

NERC gratefully acknowledges the contributions and assistance of the following individuals in the preparation of this report. NERC also would like to acknowledge the technical discussions and contributions of the NERC System Protection and Control Working Group (SPCWG).

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| Tyson Niemann | WECC |
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| Maysam Radvar | Ready Engineering |
| Lynn Schroeder | Sunflower Electric |
| Nick Stueve | Evergy |
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