

After steps 4.5.1 and 4.5.2 are completed and any required system upgrades are identified to eliminate any voltage problems or overloads, the study area CETL can be determined.

CETL for Voltage Problems

To determine the CETL for voltage problems, the imports into the study area will be increased in 50 MW increments starting from the dispatched base case identified in section 4.5.1. The import change will be modeled by increasing external generation and uniformly decreasing internal study area generation.

CETL for Thermal Problems

To determine the CETL for thermal problems, the transfer distribution factor on each of the flowgates will be calculated by using a source of generation external to the study area and a sink of generation internal to the study area. The transfer distribution factor multiplied by the increased imports will indicate which overload will limit the study area imports from a thermal perspective.

CETL for Study Area

The lower of the CETL identified for the voltage problems and the thermal problems will be used as the study area CETL.

1.0 Transitional Rules

This Load Deliverability Procedure will be applied for all future load deliverability analysis for planning years 2008 and beyond. Any existing projects identified through the RTEP for installation prior to June 2008 and approved by the PJM Board will remain requirements as identified in previous analysis.

Deliverability of Generation

The second deliverability test, the ability of an electrical area to export capacity resources to the remainder of PJM has historically been applied in situations where problems were expected to occur. Consistent with the move from IOU service territories to electrical areas, this test is applied to ensure that capacity is not "bottled" from a reliability perspective. This would require that each electrical area be able to export its capacity, at a minimum, during periods of peak load. Export capabilities at lower load levels would be based more on economic decisions and would not reflect on deliverability criteria and therefore the "certification" of resources as deliverable capacity.

Deliverability, from the perspective of individual generator resources, ensures that, under normal system conditions, if capacity resources are available and called on, their ability to provide energy to the system at peak load will not be limited by the dispatch of other certified capacity resources. This test does not guarantee that a given resource will be chosen to produce energy at any given system load condition. Rather, its purpose is to demonstrate that the installed capacity in any electrical area can be run simultaneously, at peak load, and that the excess energy above load in

that electrical area can be exported to the remainder of PJM, subject to the same single contingency testing used when examining deliverability from the load perspective. In short, the test ensures that bottled capacity conditions will not exist at peak load, limiting the availability and usefulness of certified capacity resources to system operators. In actual operating conditions, energy-only resources may displace capacity resources in the economic dispatch that serves load. This test would demonstrate that a magnitude of resources equal to or greater than the installed capacity in any given electrical area could simultaneously deliver energy to the remainder of PJM. Therefore, these tests do not require the calculation of the equivalent of export CETO and CETL values.

The electrical Regions, from which generation must be deliverable, range from individual buses to the entire regional generation under study. The premise of the test is that all capacity within the Region is required; hence the remainder of the system is experiencing a significant reduction in available capacity. However, since localized capacity deficiencies reductions are tested when evaluating deliverability from the load perspective, the dispatch pattern in the remainder of the system is modeled based on a uniformly distributed outage pattern.

Generator Deliverability Procedure

1.0 Introduction

To maintain reliability in a competitive capacity market, resources must contribute to the deliverability of the Control Area in two ways. First, energy must be deliverable, from the aggregate of resources available to the Control Area, to load in portions of the applicable PJM region experiencing a localized capacity emergency, or deficiency. PJM utilizes the CETO / CETL procedure to study this “deliverability of load”. Second, capacity resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM that are experiencing a capacity emergency. PJM utilizes a Generator Deliverability procedure to study the “deliverability of individual generation resources”. This document provides the procedure for Generator Deliverability.

2.0 Study Objectives

The goal of the PJM Generator Deliverability study is to determine if the aggregate of generators in a given area can be reliably transferred to the remainder of PJM. Any generators requesting interconnection to PJM must be “deliverable” in order to be a PJM installed capacity resource.

3.0 General Procedures and Assumptions

Step 1: Develop Base case

The RTEP base case is developed for a reference year 5 years in the future. All RTEP identified system upgrades and Supplemental RTEP Projects are included in the system model. Load is modeled at a non-diversified forecasted 50/50 summer peak load level as per the latest load forecast. All approved firm interchange is included with roll-over rights. Generation and Merchant Transmission projects that

have proceeded at least through the execution of the Facility Study Agreement stage of the interconnection process are considered in the model along with any associated network upgrades. The starting point dispatch is developed as explained in the next step. PJM uses a uniform reduction of generation in place of discrete forced outages for this test due to the significant bias any one specific outage pattern can have on the final overload results.

Step 2: Establish initial RTEP dispatch for unit under study

Place all in-service capacity resources (those that have procured capacity delivery rights) on-line at a generation value equal to their installed capacity \times (1 – PJM average EEFORd). Wind units with capacity delivery rights are derated to their granted capacity rights (either 13% beginning with the “U” queue or 20% for prior queues) representing the combined effects of wind variation and outage characteristics. The target generation value is the projected load + losses + firm interchange. (See addendum 1 for treatment of transmission withdrawal and injection rights). If all in-service capacity resources de-rated by the PJM EEFORd are greater than the target generation value, then all in-service capacity resources should be uniformly reduced to meet the target generation value. If all in-service capacity resources de-rated by the PJM EEFORd is less than the target generation value, then place all capacity resources with an executed Interconnection Service Agreement (ISA) on-line at a generation value equal to the installed capacity \times (1 – PJM average EEFORd). If all in-service and ISA capacity resources de-rated by the PJM EEFORd are greater than the target generation value, then all these resources should be uniformly reduced to meet the target generation value. If all in-service and ISA capacity resources de-rated by the PJM EEFORd is less than the target generation value, then place all capacity resources with an executed Facility Study Agreement on-line at a generation value equal to the installed capacity \times (1 – PJM average EEFORd). If all in-service, ISA and Facility Study capacity resources de-rated by the PJM EEFORd are greater than the target generation value, then all these resources should be uniformly reduced to meet the target generation value.

All resource requests in the study queue ahead of the unit under study are set at 0 MW but available to be turned on. The resource request under study is also set at 0 MW but available to be turned on. Resource requests queued after the unit under study are not modeled. The loading on each transmission line that results from this dispatch and the application of a contingency is the base loading of the facility. (See Addendum 2 for treatment of Common Mode Outage Procedures).

Step 3: Determine potential overloads

PJM uses a linear (DC) power flow program to analyze each facility for which PJM is responsible to determine whether any contingencies can overload the facility (including comprehensive flowgate analysis of single, tower, bus, and stuck breaker contingencies.) i.e., the program examines each PJM flowgate (contingency / monitored element pair) on the entire PJM footprint. The procedure below explains conceptually how the program works; following the procedure below would yield the

same results as the program. The procedure uses a load flow set up according to step 2.

Determine the distribution factor for each generator on each flowgate. The distribution factor for a particular generator is referenced to the PJM online generation. For each flowgate, multiply the distribution factor of each generator by the offline portion of the generator to obtain the MW impact the generator would have on a particular flowgate if it were ramped from its output in the initial load flow to its full output. This result will be referred to the ramping impact of a particular generator on a particular flowgate. For all flowgates determine the cumulative ramping impact of generators with greater than a 1% distribution factor. The total amount of ramped generation is capped to limit the number of potential overloads to a reasonable number of the worst impacts. A typical cap for the total ramping is 10,000 MW but the actual value can vary to establish a reasonable scope for the potential overloads. For each flowgate, add the cumulative ramping impact to the initial DC loading. If the resulting DC loading is greater than the flowgate rating, then this flowgate is a potential overload.

Step 4: Determine 80/20 DC loading

The number of generators having greater than a 1% distribution factor in Step 2 is often large enough that having them all simultaneously outputting their full installed capacity would be extremely improbable. As a result, in this step the number of generators contributing to the cumulative ramping impact on a flowgate is further restricted in the following manner.

Units modeled in the power flow with greater than a 5% distribution factor (or 10% distribution factor for flowgates whose monitored element's highest terminal voltage level is equal to or greater than 500 kV) that contribute to the cumulative ramping impact are ranked according to their distribution factor on a potentially overloaded flowgate. The availability (1 – EEFORd) of the unit with the highest distribution factor is then multiplied by the availability of the unit with the second highest distribution factor and so on until the expected availability of the selected units is as close to but not less than 20%. This resulting "80/20" cumulative ramping impact is then added to the initial DC loading on the flowgate. This resulting loading is the 80/20 DC loading and the generators chosen to contribute to the cumulative ramping impact are the 80/20 generators.

Step 5: Determine Facility Loading Adder

This Step 5 addresses off-line generators which are not included in the 80/20 list. Existing generators that do not have capacity delivery rights and active queued generators that are not yet in commercial operation (or do not yet have a signed ISA) are offline but available to be turned on. The ramping impact of this set of generators determines the Facility Loading Adder. First, for their ramping impact to be considered, off-line generators must pass the impact threshold of at least a 5% DFAX (10% for flowgates with monitored elements having the highest terminal

voltage 500 kV and above) on a flowgate or with an impact (DFAX times a generator's full energy output rating) greater than 5% of the flowgate's rating.

The ramping impact of offline generators is determined according to their classification as: (1) existing generators that do not have capacity delivery rights and active queued generators with signed ISA's, or (2) active queued generators without signed ISA's. Category (1) generators are allowed to aggravate or backoff overloaded flowgates. Category (2) generators are considered only if they aggravate overloaded flowgates (active queued generators without signed ISAs are not allowed to backoff overloads.)

The amount of generation change from the initial load flow due to changes in 80/20 and Facility Loading Adder generation shall not be any more than the online installed capacity exclusive of the 80/20 generators x PJM average EEFORd. Ramping impacts for lower DFAX offline generators that do not influence the 80/20 cumulative ramping impact are not considered when this threshold is exceeded.

The ramping impact of active queued generators without signed ISA's considers the commercial probability of queued generators at the feasibility and impact study stage of the interconnection process. For generators at the feasibility study stage of the interconnection process, the output of the generator is multiplied by the historic commercial probability of a generator at the feasibility study stage of the interconnection process. For generators at the impact study stage of the interconnection process, the output of the generator is multiplied by the historic commercial probability of a generator at the impact study stage of the interconnection process. To be conservative, these values are then multiplied by 150% to determine the ramping impact of generation at the feasibility study and impact study stage of the interconnection process. The entire requested capacity of queued generation is used to determine the ramping impact of generation that has signed a facility study agreement.

The summation of 85% (100% for a Merchant Transmission project) of the ramping impact on a flowgate of each off-line resource that meets the above conditions is calculated. The resulting impact defines the Facility Loading Adder. The Facility Loading Adder is added to the base loading and the 80/20 DC loading to obtain the final DC loading on the facility.

Step 6: Determine Final Flowgate Loading

If a flowgate has a final DC loading less than 90% of its rating, it is not considered to be overloaded and is not tested further. If a flowgate has a final DC loading greater than or equal to 90% of its rating, the 80/20 generators are ramped up to their installed capacity in the load flow from step 2 and all remaining PJM generators are uniformly ramped down such that the PJM firm interchange is maintained. The resulting flowgate loading is the 80/20 AC loading.

The Facility Loading Adder can sometimes have a significant impact on the results of a deliverability study. However, ramping up the units associated with the adder in the load flow will typically create too much localized generation and a localized

capacity emergency condition elsewhere when the rest of PJM is proportionally displaced to maintain the firm interchange. Therefore, to account for the effect of these units on the facility in question, the Facility Loading Adder, as determined in Step 5, is added to the 80/20 AC loading to result in the Final Flowgate Loading. This Facility Loading Adder accounts for the ramping impact of those offline resource requests that are both electrically close to a flowgate and did not participate as an 80/20 generator without actually turning them on. If the cumulative ramping impact of these offline resource requests has a beneficial effect on the flowgate, then the loading of the flowgate will be decreased to account for this beneficial effect. Similarly, the flowgate loading will be increased if these offline resource requests will further add to the overload.

In summary, the 80/20 generators will define the study area *for a particular flowgate* by determining which units to ramp up. All remaining online units are proportionally displaced to some level below their installed capacity $\times (1 - \text{PJM average EEFORd})$ to maintain the firm PJM interchange.

Addendum 1: Modeling Transmission Withdrawal Rights (TWRs) and Transmission Injection Rights (TIRs)

Firm TWRs and TIRs may be associated with a controllable merchant transmission request, i.e. HVDC, which interconnects PJM to another system. If the transmission request has an executed ISA associated with it, the firm rights are modeled at their full amount. When the firm rights are modeled, the initial dispatch in step 2 will need to be modified to support these rights. If the transmission request does not have an executed ISA and is queued ahead of the project under study or is the project under study the following rules apply; for TWRs the sign of the distribution factor is changed for the purpose of deciding whether to model the right. The right is modeled at its full amount if a generator with its distribution factor would be in the 80/20 list. The right is treated as a Facility Loading Adder using the rules of Step 5.

Addendum 2: Common Mode Outage Procedure

In addition to single contingencies, PJM planning criteria requires that the PJM system withstand certain common mode outages. These outages include line faults coupled with a stuck breaker, double circuit tower line outages, faulted circuit breakers and bus faults. PJM uses a procedure very similar to the generator deliverability procedure to study common mode outages. The list below highlights the other details of the common mode outage procedure that differ from the generator deliverability procedure.

In addition to the modeling of capacity resource requests, all existing energy resources and energy resource requests queued ahead of the unit under study are set at 0 MW but available to be turned on. The energy resource request under study is also set at 0 MW but available to be turned on. Energy resource requests queued after the unit under study are not modeled.

A 50/50 DC loading is used instead of an 80/20 DC loading, i.e., the expected availability of the selected units is close to but not less than 50%.

For all voltage levels, a 10% distribution factor is used instead of a 5% distribution factor to select the 50/50 generators.