NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference

Version 2.0
Document ID: 1062
Approval Date: 09/11/2020

Versioning and Acknowledgments

Version History

Date	Version	Notes
04/30/2015	2015-1	Initial version.
09/11/2020	2.0	Full review conducted; no changes made, other than placing on current template.

Review and Update Requirements

- Review: every 5 years
- Update: as necessary

Table of Contents

Section 1: Generating Unit Reactive Power Capability Modeling Reference Document Scope

Note 1: This Reference Document applies to synchronous generators only.

Note 2: This Reference Document uses the term 'Generator Entity' to refer to both the Generator Owner and Generator Operator. Depending on how a particular company is organized, responsibilities may be assigned to either the Generator Owner or Generator Operator.

Note 3: This Reference Document does not create binding norms, establish mandatory reliability standards or create parameters by which compliance with Reliability Standards are monitored or enforced. In addition, this Reference Document is not intended to take precedence over any regional procedure. It is recognized that individual Generator Owners and Transmission Owners may use alternative and/or more specific approaches that they may deem more appropriate for their generators and transmission systems.

A generating unit's capability to provide reactive power support is essential in maintaining adequate system voltage profiles under a variety of steady-state (normal and contingency) conditions for ensuring Bulk Electric System (BES) Reliability.

It is important to recognize that the "generator" reactive power capability curve only represents the capability of the electrical generator itself. The manufacturer generator reactive power capability curve or D-curve does not take into account: a) the design of the auxiliary power system and its coordination with the generator terminal voltage; b) the GSU transformer electrical characteristics; c) the strength of the transmission system to which the generator is connected; d) the transmission operating voltage and coordination with the GSU transformer tap setting; and e) generator protection system settings. These five factors will affect the "generating unit" reactive power capability. The distinction between the "Generator" reactive power capability and the "Generating Unit" reactive power capability must be understood, evaluated and reported so the generating unit can be modelled correctly in Transmission Operations and Planning studies. For additional information on this concept see Appendix A: Understanding Generator and Generating Unit Reactive Power Capability.

In addition to the above considerations, Generating Unit reactive power factor requirements are generally governed by the Interconnection Agreement between the Generator Entity and the Transmission Owner/Operator. These Interconnection Agreement requirements often define a narrower band or range within a generating unit's rated capability curves.

Transmission planners and operators use models of generating units as part of their responsibility to ensure reliable and economic operation of the grid. Most present network analysis tools use fairly simple representations to depict each unit's reactive power capabilities at fixed minimum and maximum reactive power limits. The lagging and leading generator reactive power capability available to the transmission system is specific to each unit and can vary significantly based on numerous factors. These simple representations do not typically take into account key variables such as transmission system voltage, generator and auxiliary bus voltages, transformer tap settings, MW output level, the impacts of excitation system controls and limiters, effects of cooling provided by variable hydrogen pressure, ambient air, etc.

Staged reactive power tests have been used to verify and document a generating unit's reactive power capability. It is important to recognize that the test results are representative of each unit's reactive power capability for the prevailing conditions at the time of the test. The same unit may have significantly more or less reactive power capability under different operating conditions. Therefore, tests performed under a single set of conditions may not be adequate to provide the full picture of a unit's reactive power capability. Consequently, the tests may result in reduced reactive power capability in comparison to the actual reactive power capability achievable under different sets of conditions.

Presently, there is no consistent, industry-wide approach for ensuring that generator voltage and reactive power limits are determined and reported appropriately for use in the various types of steady-state studies performed. Developing a reference document for verification and reporting of generating unit reactive power capability for steady state studies performed by transmission planning and operations has been identified by the North American Transmission Forum's Modeling Practices Group (NATF MPG) as a high priority initiative. The NATF Modeling Practices Group's (MPG) Generator Reactive Modeling Working Group (GRWG) reviewed the major factors affecting the ability of a generating unit to produce lagging and leading reactive power. From this review, the group is providing information for help in determining, verifying, reporting, and modeling generating unit reactive power capabilities and associated limitations for use in steady-state evaluations of Bulk Electric System (BES).

Section 2: Generating Unit Reactive Power Capability Modeling Reference Document Objectives

This NATF Modeling reference document 'Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines' is intended to provide guidance towards the use of consistent, industry-wide approaches for verifying, reporting and validation of generating unit reactive power capability. This document does not replace, change, or interpret any requirements in NERC Reliability Standards or other applicable criteria.

The reactive power limits used in the transmission planning and transmission operations power flow simulations should be based upon the "Generating Unit" reactive power capability rather than the "Generator" reactive power capability. An understanding of and distinction between "Generator" and "Generating Unit" reactive power capability is provided in Appendix A: Understanding Generator and Generating Unit Reactive Power Capability.

With proper coordination and data sharing, appropriate "Generating Unit" reactive limits can be determined via simulations performed by the Generator Entity and/or the Transmission Planner. The steps recommended for determining "Generating Unit" reactive limits are discussed in Section 3: Determination of Generating Unit Reactive Limits for Use in Transmission System Models. Implementation of these limits, i.e. using them as a guideline for operation of generators or making them mandatory, is a separate matter, however. Therefore, it is recommended that there be a joint review of these limits between the Transmission Entity and the Generator Entity prior to their use.

On-Line unit performance should be reviewed and used to help validate the "Generating Unit" reactive power limits and the models developed in Section 3. Validation can be based upon operational history data or staged-testing. These approaches are discussed in Section 4: Validation of Generating Unit Reactive Power Capability. The test results or operational data can be compared to the results obtained in Section 3 to refine the "Generating Unit" model and reactive power limits to be used in the transmission planning and transmission operations power flow simulations.

Modeling of generator reactive power capability is important for various types of power flow (also known as load flow) studies. Power flow analysis is performed for different objectives and with various time horizons. An introduction to reactive power capability modeling and differences between real-time operations, operational planning, and long-term planning studies is provided in Appendix E: Transmission Study Horizons. While there should be consistency in modeling of generating unit reactive power limits within certain types of studies, e.g. operations versus mid- and long-range planning, the most suitable generating unit representation could vary e.g., consistent with expected voltage deviations from generator voltage schedules. Operations studies may be performed in an intentionally conservative manner whereas planning studies with light or heavy loads or with multiple overlapping contingencies could be performed with generating unit reactive power capabilities expected with higher or lower transmission grid voltages than those experienced during normal system conditions.

Transmission Entities perform a variety of operating and planning studies (See Appendix E for additional discussion) and the representation of the generating unit varies in the different models (See Appendix F: Representation of Generators in Power Flow models for additional discussion). Transmission Entities need the generating unit reactive power capability limits at the generator terminals and the point of interconnection to be provided in a consistent format so that they can select appropriate limits to be modeled in their planning and operating studies over a range of transmission system operating conditions including voltages. It is suggested that the limits be developed following the approach outlined in this document and communicated, as necessary, on both a generator capability curve (D-curve) as well as in a tabular format as described in Section 3.1, step 5, part 2.

> Note: The reference document does not provide a "one size fits all" approach to methods for determining "generating unit reactive power capability." It does, however, provide various methods for obtaining generator and generating unit limits that can be factored into the Transmission modeling process. Examples of current processes from Forum members are provided. The goal is to ensure that generating unit reactive power limits are determined and reported appropriately for use in various types of transmission system studies.

Section 3: Determination of Generating Unit Reactive Power Limits for Use in Transmission System Models

Determination of the Generating Unit reactive power limits for use in transmission system models requires coordination between and cooperation of both the Generator Entity and the Transmission Planner. Two approaches are presented.

- Section 3.1 describes the modeling that could be done by the Generator Entity and the data necessary from the Transmission Planner.
- Section 3.2 describes the modeling that could be performed by the Transmission Planner and the data necessary from the Generator Entity.

3.1 Generator Entity Engineering Study

The following outlines an approach that can be used by a Generator Entity to determine generating unit reactive power limits for use in transmission system models. This method employs an "all-the-tools-in-the-toolbox" approach which can be summarized as follows:

1. Establish Generating Unit Power Flow Model
2. Obtain Operational or Test Data
3. Validate Power Flow Model with Operational/Test Data
4. Perform Reactive Power Capability Simulations (Specific unit load points and POI transmission voltages)
5. Document Results for Reporting
    a. Obtain Plant Operations Staff Review & Feedback
    b. Transmit Results to Transmission Planner/Reliability Coordinator

Each of these steps are discussed in more detail below as applied to an example generating unit.

Step 1 - Establish Generating Unit Power Flow Model

The following inputs are needed for development of the model:

- Unit Configuration/Drawings (Single Line (S/L), 3-Line, etc.)
- Generator Ratings & Manufacturer's D-Curve (See Appendices A and B)
- Excitation Limiter Setpoint Study / As-Left Settings
- GSU, UAT, SST Ratings, %Z, Tap Settings (GSU-Generator Step Up transformer, UAT-Unit auxiliary transformer, SST- station service transformer)
- Gross MW values at which reactive power capabilities/limits are to be validated
- Auxiliary Load (MW and MVAR or PF) at which reactive power capabilities/limits are to be determined
- Transmission Bus High and Low Voltage Extremes at which reactive power capabilities/limits are to be validated. These are typically based on the applicable Transmission Owner/Operator requirements which specify the voltages at the point of interconnection
- Generating Unit Equipment Ratings & Operating Limits
    - Generator Bus, Breaker, and Switch Ampere Limits
    - Generator & Station Auxiliary Bus Voltage Limits. Generator design voltage limits are typically 105%/95% of the rated (nameplate) value (reference: IEEE C50.13). For some entities, auxiliary bus limits are typically based on 110% of motor nameplate voltage (per NEMA MG-1) and between 92.5% and 95% of nominal bus voltage. [The Generator Owner (GO) is ultimately responsible for establishing these bus voltage limits to ensure safe and reliable operation of the station auxiliary system over a wide array of operating conditions for an unlimited period.]

  Appendix A provides additional information on the generator and auxiliary system equipment voltage limits and their impact on unit reactive capability.

The following are the basic model components needed for a comprehensive study. Determination of the specific station auxiliary system components to be modeled explicitly depend upon the specific unit design and configuration being modeled. Typically, the model should include each medium voltage bus along with low voltage buses whose operating voltage limits can potentially limit the generator operating terminal voltage range.

- Generator (See the D-curve plot below (Figure 1) for this example)

  - MVAR production limits from D-curve (consider margins, voltage impact, tolerances) at full (maximum) and minimum generator gross load
  - MVAR absorption limits from Minimum Excitation Limiter settings (consider margins, voltage impact, tolerances) at full (maximum) and minimum generator gross load
  - Review Over Excitation Limiter (OEL), Field Current Limiter, Volts per Hertz (V/Hz), armature (stator) current limiter, other limiter settings or alarms that could potentially limit operation within the Generator reactive power capability curve or operating voltage range
  - Factor in other known reactive power limitations (ex: generator cooling, H_2 pressure, vibration, de-rated rotor, derated GSU transformer, generator bus derating, etc.)

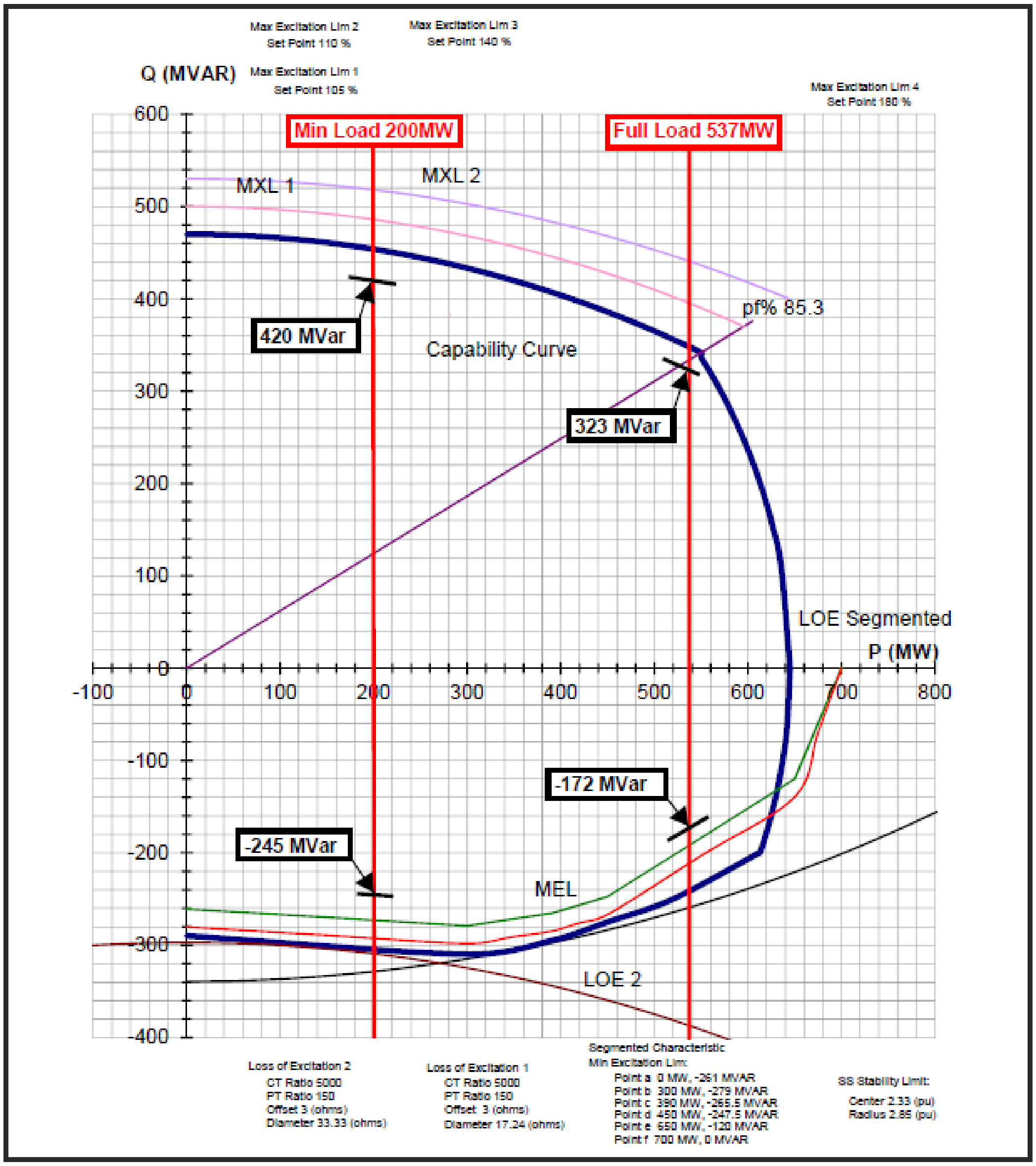


Figure 1

- Generator Bus - include voltage & ampere ratings
- GSU Transformer – consider MVA & voltage ratings, %Z, field verified tap setting

- Transmission System Equivalent (typically an infinite bus is used)
- Transmission System Bus voltages (High, Schedule or Low) to use for each reactive power limit power flow simulation
- Unit Auxiliary Transformers (UATs) & Other Station Service Transformers (SST) - include MVA & voltage ratings, %Z, field verified tap settings
- Station Service Buses supplied by UATs and downstream low voltage SSTs. Include applicable voltage limits

Note that equipment problems and/or reductions in equipment ratings that cause VAR limitations should be documented and reported for consideration of impacts to Operating and Planning models (ex: turbine-generator vibration, de-rated generator rotor, generator or transformer cooler degradation, bus connection hot spots or cooler issues).

Below (Figure 2) is an example of a power flow model developed for a typical fossil unit:

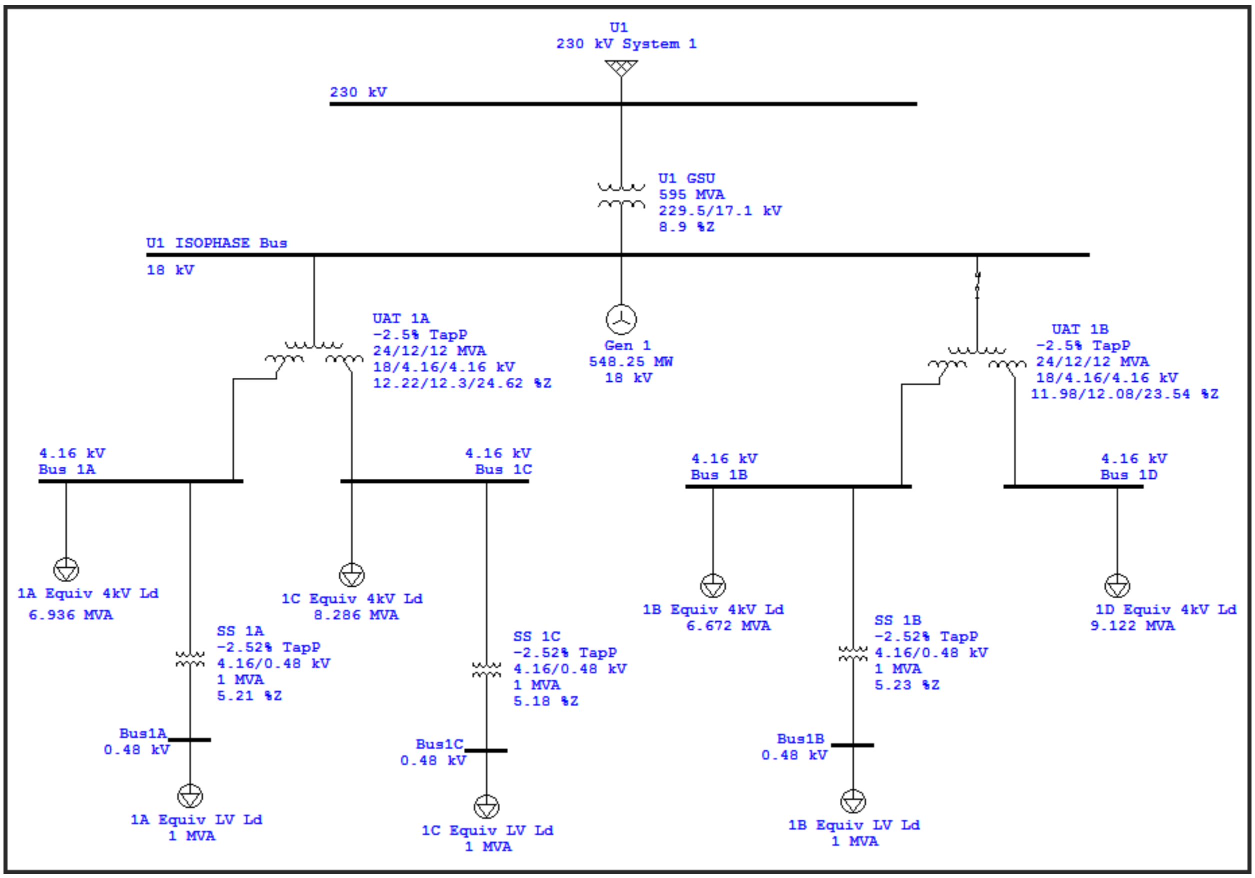


Figure 2

Note the foregoing model includes explicit representations of the generator, GSU transformer, unit auxiliary transformers, medium voltage buses, medium to low voltage station service transformers, and low voltage buses. The model also includes equivalents of the unit medium and low voltage bus loads and the transmission system at the point of interconnection.

Step 2 - Obtain Operational or Test Data

Scheduling of any tests should first be coordinated with the Transmission Operator. Data needed for validation of the power flow model can include the following:

- Transmission System Bus Voltage (high side GSU voltage) at the time of the test or operating data capture/snapshot
- Generator Voltage, MW, MVAR (or PF)
- Station Auxiliary Bus MW, MVAR (or Amp and PF) Load. This information may not be readily available in some cases, especially for LV systems*
- Station Auxiliary Bus Voltages (This would include the medium voltage buses and low voltage buses (575 V, 480 V). This information may not be readily available in some cases, especially for LV systems *
  * This information can often be obtained by field readings using available instrumentation. If instrumentation is not available, reasonable estimates can be made based on reviews of bus one line diagrams and discussions with plant operations staff.

All data should be taken/captured at the same time whether during a test or from a review and use of operational data.

The following additional data can also be useful for comparisons with equipment design ratings when reviewing for potential limitations that are not directly represented in the electrical power flow simulations:

- Generator Field Amps, Field Volts, Field Temperatures
- Generator Cooling Parameters (H_2 Pressure, Inlet Water/Air Temp, Stator Winding Temp, etc. as applicable)
- GSU transformer winding and oil temperatures
- Ambient temperature

For historical operational data obtained, the transmission system voltage will typically be at or near schedule. Transmission Operators will assist in determining the amount of voltage variation that is acceptable. When scheduling tests or selecting operational data, the seasons and times of day that are conducive to the required reactive power capabilities should be considered. It is recommended to obtain at least two sets of data. The following are suggestions for a typical fossil unit:

Set 1 – Typical high MVAR production with unit operating at or near normal full load MW.
Set 2 – Typical high MVAR absorption with unit operating at or near minimum stable MW load.

Step 3 – Validate Power Flow Model with Operational or Test Data

- **Compare Simulated Results to Actual Data to Validate Model**
  - Power Flow Simulation MW, MVAR, Voltages, Amps
  - Operational or Test MW, MVAR, Voltages, Amps
- **Good Match Demonstrates:**
  - Model is representative of actual generating unit electrical system operation
  - Model can be used to simulate the unit operation and “Take it to the Limit” (MVAR and/or voltage) for various transmission bus voltages

- Model can also be used to study various generating unit operating conditions (ex: Maximum and Minimum Unit MW loading)

Note: This same Methodology is used for nuclear plant safe shutdown capability verification. The NRC established the precedent for this method in Degraded Grid electrical system studies.

To illustrate, below (Figure 3) is a power flow model validation simulation for an example sample fossil unit, as well as a table (Figure 4) that compares the model calculated results versus operational data taken.

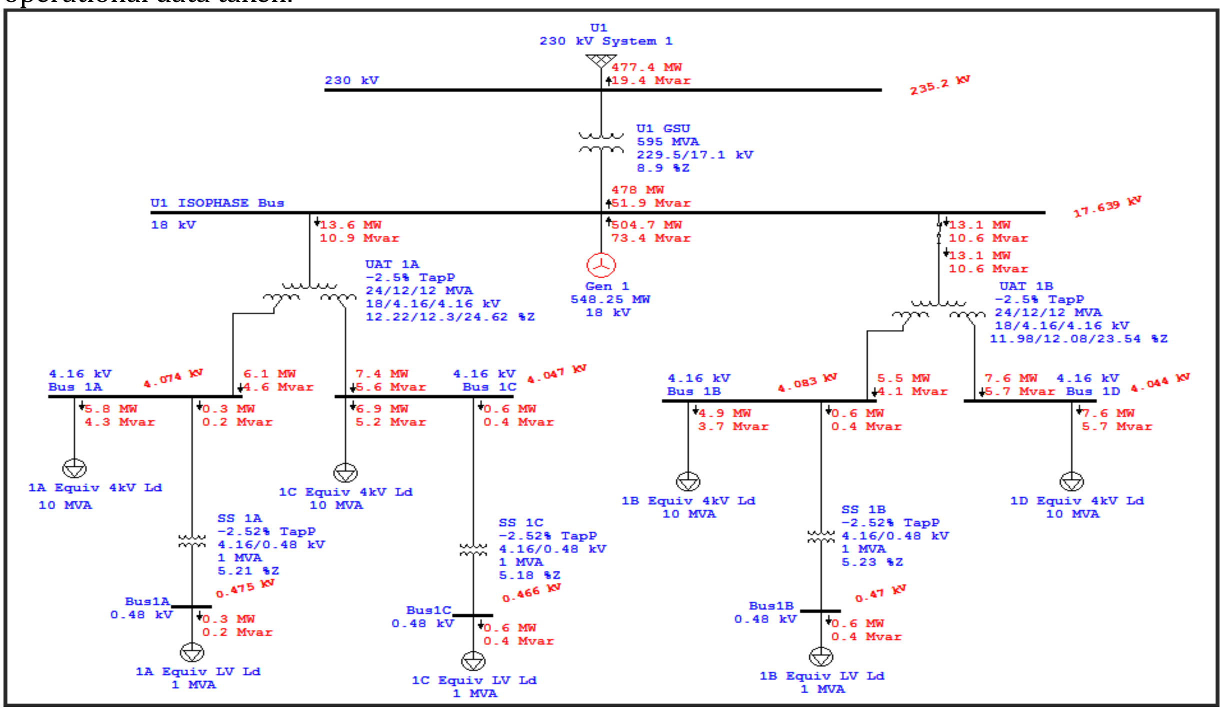


Figure 3

Table 3. Model Validation Case 1 for Unit 1

Model Validation Case 1 - Results Using Typical MVARout (8/19/2009 10:25 AM)						
Equipment	Data Source	MW	MVAR	Current	Voltage	
				Amp	kV	%
Generator 1	Unit Operating Data	504.7	73.4	N/A	17.90	99.4%
	Model Power Flow	504.7	73.4	16,694	17.64	98.0%
4.16 kV SS Bus 1A	Unit Operating Data	–	–	1,086	4.06	97.6%
	Model Power Flow	6.1	4.6	1,079	4.074	97.9%
4.16 kV SS Bus 1B	Unit Operating Data	–	–	970	4.07	97.8%
	Model Power Flow	5.5	4.2	976	4.082	98.1%
4.16 kV SS Bus 1C	Unit Operating Data	–	–	1,333	4.06	97.6%
	Model Power Flow	7.4	5.6	1,329	4.047	97.3%
4.16 kV SS Bus 1D	Unit Operating Data	–	–	1,365	4.05	97.4%
	Model Power Flow	7.6	5.7	1,355	4.044	97.2%
480 V SS Bus 1A	Unit Operating Data	–	–	443	0.48	100.0%
	Model Power Flow	0.30	0.20	448	0.475	99.1%
480 V SS Bus 1B	Unit Operating Data	–	–	890	0.47	97.9%
	Model Power Flow	0.60	0.40	889	0.470	97.9%
480 V SS Bus 1C	Unit Operating Data	–	–	853	0.47	97.9%
	Model Power Flow	0.60	0.40	857	0.466	97.1%
230 kV Bus	Unit Operating Data	N/A	N/A	N/A	235.2	102.3%
	Model Power Flow	477.3	19.4	1,173	235.2	102.3%

Notes:

1) Differences between measured operational values and power flow calculated values attributed primarily to instrumentation error.

2) Power factor (PF) of 80% is assumed to calculate the Real Power (MW) and Reactive Power (MVAR) using voltage and current field data.

Figure 4

Note that the generator and station auxiliary bus loads were adjusted to closely match the loads from the field data. The model is validated if the calculated voltages from the power flow results closely match the corresponding voltages from the field data.

Step 4 - **Perform Reactive Power Capability Simulation**

Run Power Flow Simulations Using Validated Model

- Important: Amount of Station Service (SS) Load for Specified Unit MW Output.
- Important: Appropriate Distribution of SS Load Among Buses.
- Lightly Loaded SS Buses – Can Limit Unit Lagging VAR Capability (Bus Volts too high).
- Heavily Loaded SS Buses – Can Limit Unit Leading VAR Capability (Bus Volts too low).
- Equivalent bus loadings (MW + jMVAR or Amps & PF) for the cases to be studied can be determined from operating history trends. For the example unit, the following trend data (Figures 5-8) was available to help establish 4160 V SS bus MW loadings and PFs when the unit is operating at or near full MW load during summer conditions.

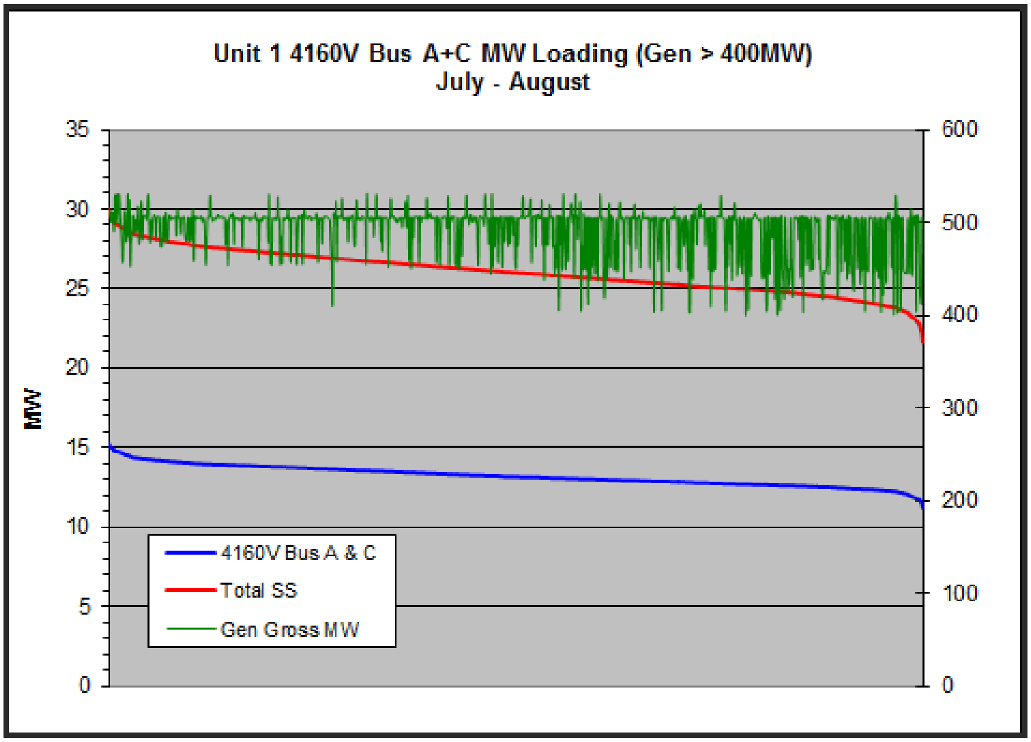


Figure 5

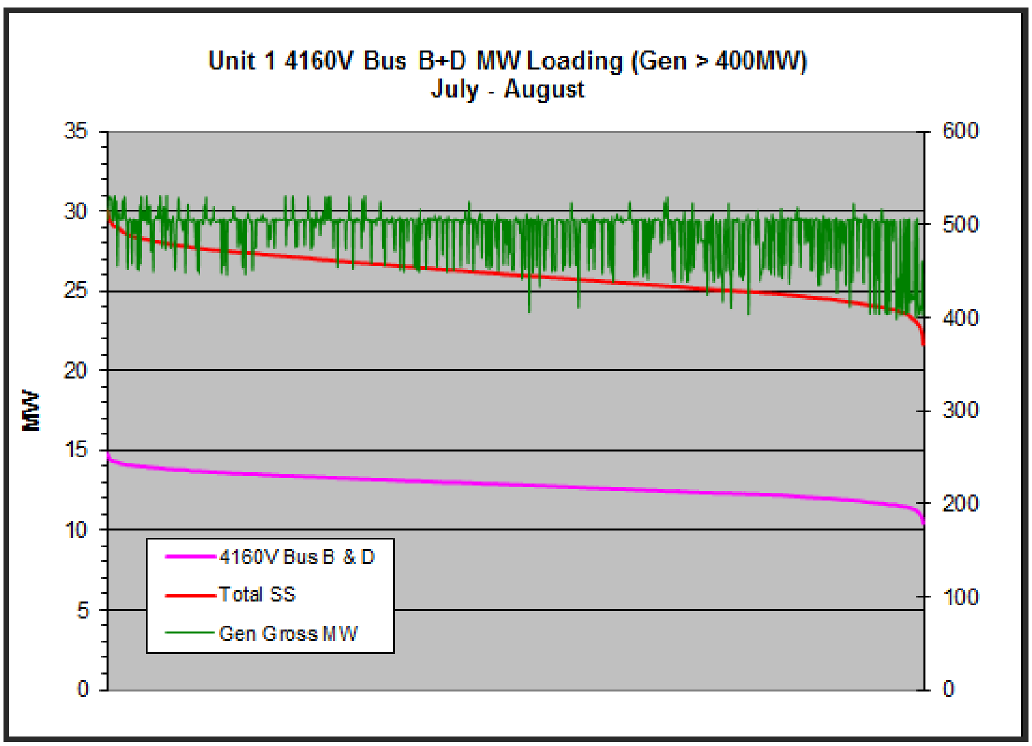


Figure 6

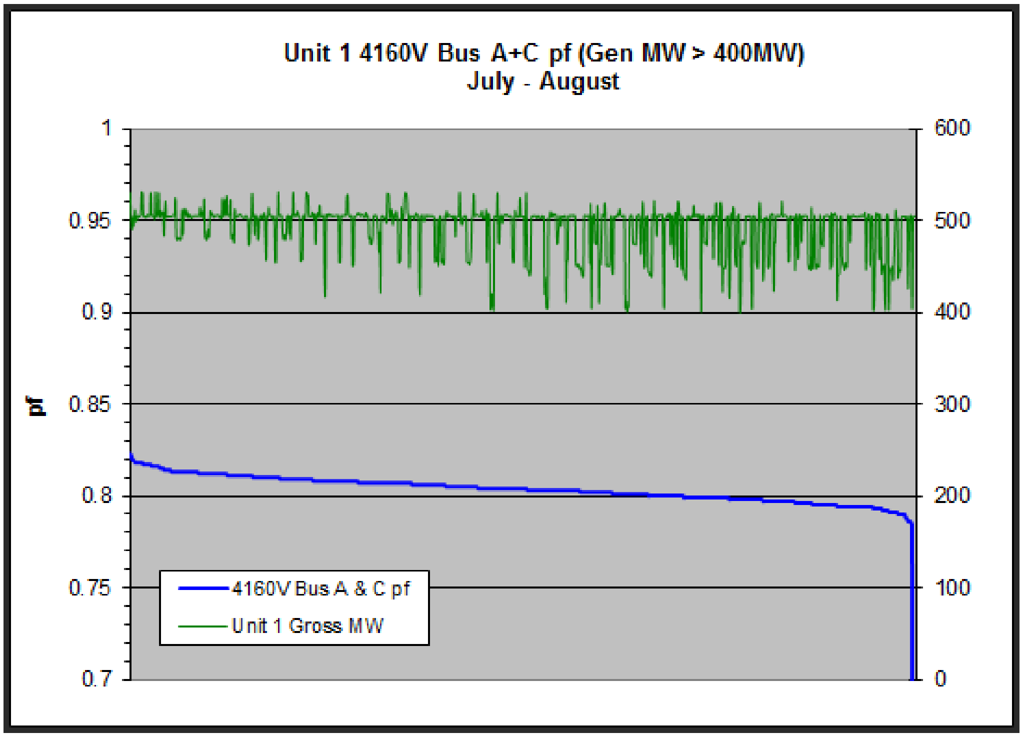

Unit 1 4160V Bus A+C pf (Gen MW > 400MW)
July - August
pf
1
0.95
0.9
0.85
0.8
0.75
0.7
600
500
400
300
200
100
0
4160V Bus A & C pf
Unit 1 Gross MW

Figure 7

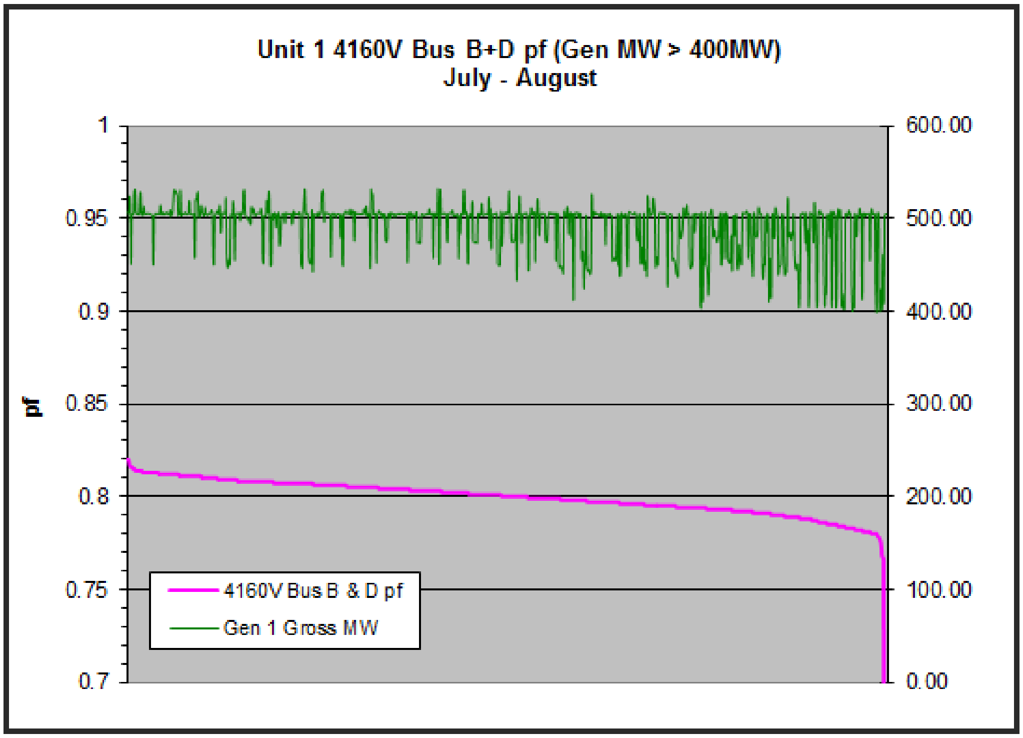


Figure 8

1. Determine Reactive Power Limits for Generator Full Load (Maximum) Gross MW and Generator Minimum Gross MW

It is recommended that the Generating Unit reactive power capabilities be determined at the following four points as a minimum:

- Leading (absorbing) reactive power capability at normal full generator gross MW load;
- Lagging (producing) reactive power capabilities at normal full generator gross MW load;
- Leading (absorbing) reactive power capability at normal minimum generator gross MW load;
- Lagging (producing) reactive power capability at normal minimum generator gross MW load.

Since a generating unit's reactive power capabilities vary depending on unit and system operating conditions, the Generator Entity should coordinate with the Transmission Planner to establish the specific conditions or range of conditions for which these unit reactive power limit points need to be determined. If the Transmission Planner does not specify the transmission system voltages to be used, then at a minimum, it is recommended to determine reactive power capabilities with the transmission system voltage at a realistic value.

That is, the system voltage should be between the TP's min-allowed and specified values for max–lagging tests, and between the max-allowed and specified values for max–leading tests. This is opposite the direction naturally occurring during tests; MVAR export drives system voltages higher, and MVAR import makes voltages lower. This tendency can be counteracted to some degree by operating generators in a push-pull fashion, i.e. taking not-tested units to min MVAR when the tested until is at max MVAR, and vice versa. Some participation by the TOP will be needed to attain the above-stated goal, however, by coordinating push-pull at other plants in the area or manipulating transmission system capacitor banks, reactors, static VAR compensators or load tap changers.

If the generating unit reactive power capability limits are less than indicated by the D curve, additional simulations can be performed to determine the unit reactive power limits at other transmission system voltages. If the Transmission Planner does not prescribe specific voltages for the sensitivity analyses, the Generator Entity can perform additional simulations at transmission voltages that produce generating unit reactive power limits that are comparable to the limits indicated by the D curve. Additional leading (absorbing) reactive power capability simulations should be performed for higher transmission voltages and additional lagging (producing) reactive power capability simulations should be performed for lower transmission voltages. These power flow simulations must demonstrate that generator and auxiliary bus voltages remain within acceptable limits at the leading and lagging reactive power limits. It must also be determined that the model captures the reason for less-than-D-curve test results well enough that the other-voltage results can be relied-upon.

As an illustration:
For the typical unit the SS trend data along with field data recorded for the validation cases were used to estimate SS bus loadings (MW & PF) for determining the unit's reactive power capabilities at summer full load MW operation using the validated load flow model.

The following power flow simulations evaluate the generating unit reactive power capabilities for lagging (Figure 9) and leading (Figure 10) PF operation at transmission bus voltage conditions prescribed by the Transmission Planner.

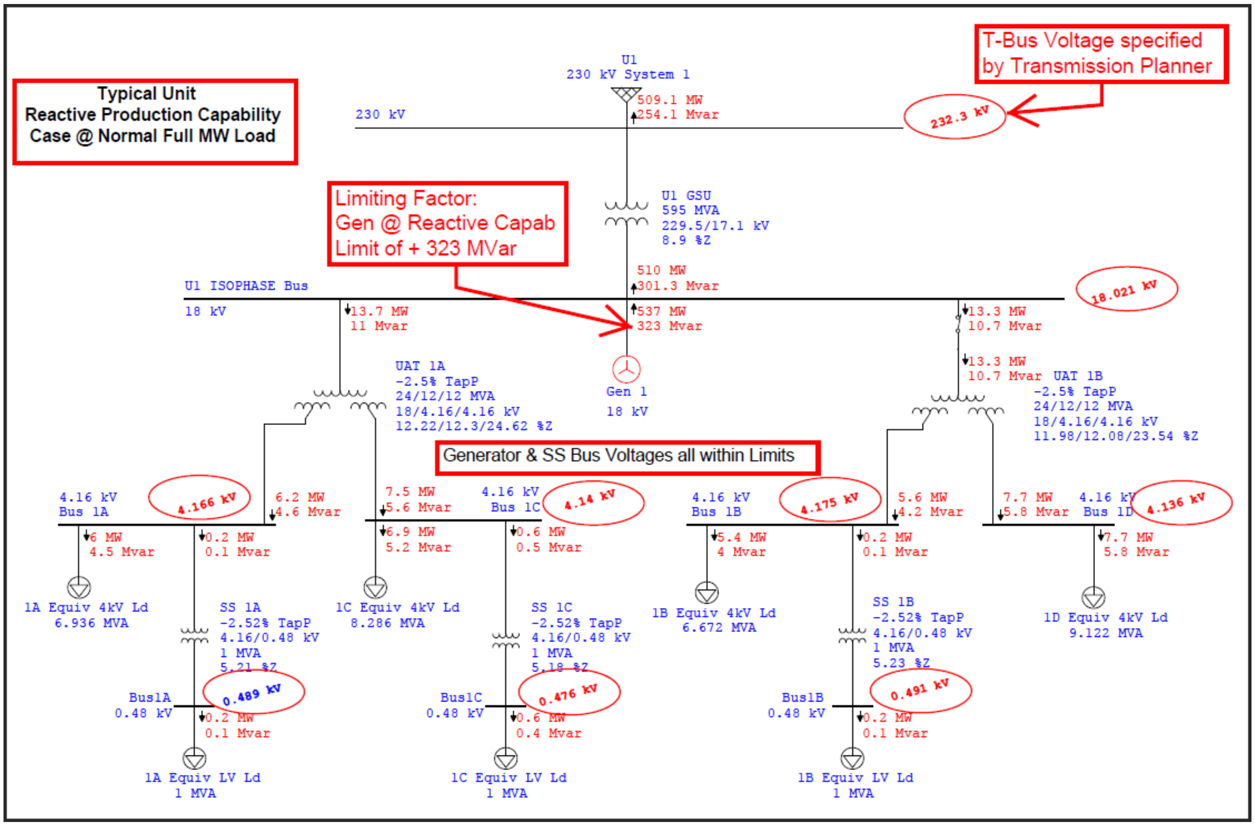

Typical Unit
Reactive Production Capability
Case @ Normal Full MW Load
T-Bus Voltage specified
by Transmission Planner
Limiting Factor:
Gen @ Reactive Capab
Limit of + 323 MVar
Generator & SS Bus Voltages all within Limits
U1
230 kV System 1
509.1 MW
254.1 Mvar
230 kV
232.3 kV
U1 GSU
595 MVA
229.5/17.1 kV
8.9 %Z
510 MW
301.3 Mvar
U1 ISOPHASE Bus
18 kV
18.021 kV
13.7 MW
11 Mvar
537 MW
323 Mvar
Gen 1
18 kV
13.3 MW
10.7 Mvar
UAT 1A
-2.5% TapP
24/12/12 MVA
18/4.16/4.16 kV
12.22/12.3/24.62 %Z
UAT 1B
-2.5% TapP
24/12/12 MVA
18/4.16/4.16 kV
11.98/12.08/23.54 %Z
4.16 kV
Bus 1A
4.166 kV
6.2 MW
4.6 Mvar
7.5 MW
5.6 Mvar
4.16 kV
Bus 1C
4.14 kV
4.16 kV
Bus 1B
4.175 kV
5.6 MW
4.2 Mvar
7.7 MW
5.8 Mvar
4.16 kV
Bus 1D
4.136 kV
6 MW
4.5 Mvar
0.2 MW
0.1 Mvar
6.9 MW
5.2 Mvar
0.6 MW
0.5 Mvar
5.4 MW
4 Mvar
7.7 MW
5.8 Mvar
1A Equiv 4kV Ld
6.936 MVA
SS 1A
-2.52% TapP
4.16/0.48 kV
1 MVA
5.21 %Z
1C Equiv 4kV Ld
8.286 MVA
SS 1C
-2.52% TapP
4.16/0.48 kV
1 MVA
5.18 %Z
1B Equiv 4kV Ld
6.672 MVA
SS 1B
-2.52% TapP
4.16/0.48 kV
1 MVA
5.23 %Z
1D Equiv 4kV Ld
9.122 MVA
Bus1A
0.48 kV
0.489 kV
Bus1C
0.48 kV
0.476 kV
Bus1B
0.48 kV
0.491 kV
0.4 Mvar
1A Equiv LV Ld
1 MVA
1C Equiv LV Ld
1 MVA
1B Equiv LV Ld
1 MVA

Figure 9

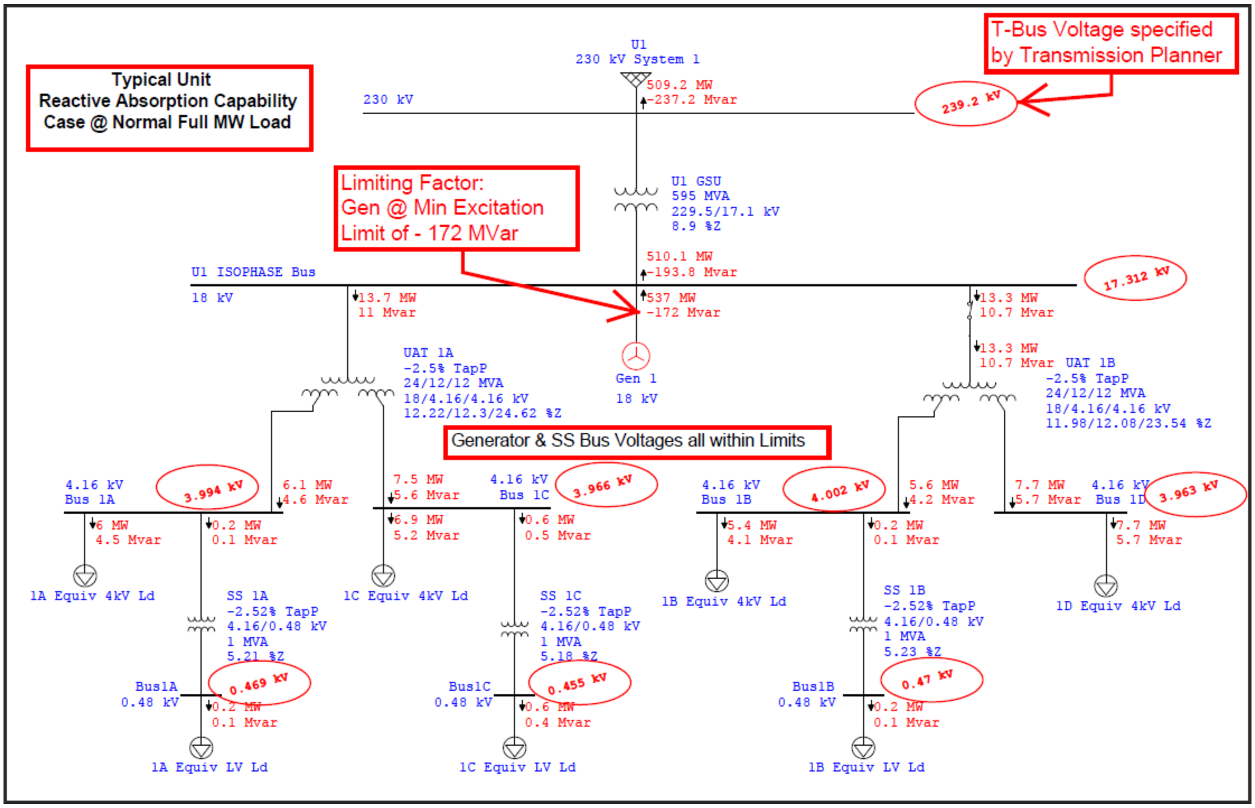


Figure 10

For the example unit, SS trend data along with field data recorded for the validation cases were also used to estimate SS bus loadings (MW & PF) for determining the unit's reactive power capabilities at <u>minimum load MW</u> operation using the validated power flow model. The following power flow simulations evaluate the unit reactive power capabilities for lagging (Figure 11) and leading (Figure 12) PF operation at transmission bus voltage conditions prescribed by the Transmission Planner in this instance:

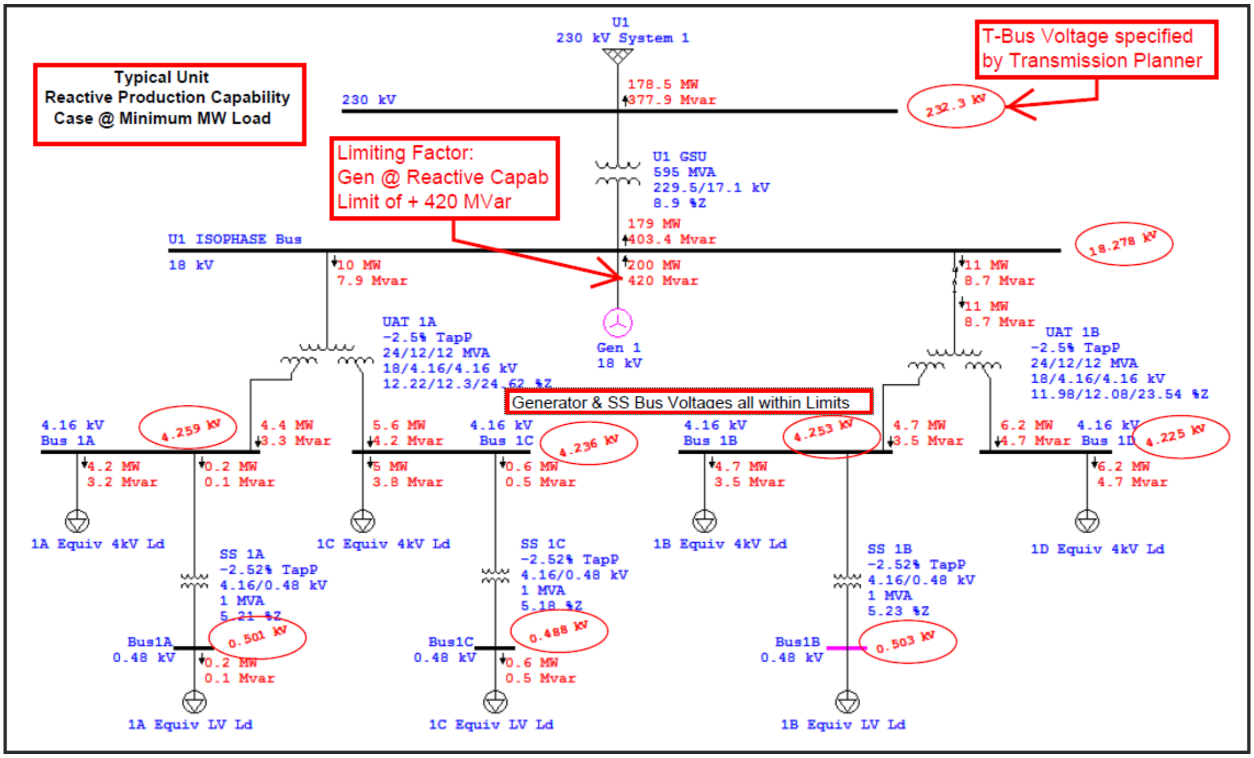

Typical Unit
Reactive Production Capability
Case @ Minimum MW Load
Limiting Factor:
Gen @ Reactive Capab
Limit of + 420 MVar
T-Bus Voltage specified
by Transmission Planner
Generator & SS Bus Voltages all within Limits
U1
230 kV System 1
230 kV
178.5 MW
377.9 Mvar
232.3 kV
U1 GSU
595 MVA
229.5/17.1 kV
8.9 %Z
179 MW
403.4 Mvar
U1 ISOPHASE Bus
18 kV
18.278 kV
10 MW
7.9 Mvar
200 MW
420 Mvar
11 MW
8.7 Mvar
Gen 1
18 kV
UAT 1A
-2.5% TapP
24/12/12 MVA
18/4.16/4.16 kV
12.22/12.3/24.62 %Z
UAT 1B
-2.5% TapP
24/12/12 MVA
18/4.16/4.16 kV
11.98/12.08/23.54 %Z
4.16 kV
Bus 1A
4.259 kV
4.4 MW
3.3 Mvar
5.6 MW
4.2 Mvar
Bus 1C
4.236 kV
Bus 1B
4.253 kV
4.7 MW
3.5 Mvar
6.2 MW
4.7 Mvar
Bus 1D
4.225 kV
4.2 MW
3.2 Mvar
0.2 MW
0.1 Mvar
5 MW
3.8 Mvar
0.6 MW
0.5 Mvar
1A Equiv 4kV Ld
1C Equiv 4kV Ld
1B Equiv 4kV Ld
1D Equiv 4kV Ld
SS 1A
-2.52% TapP
4.16/0.48 kV
1 MVA
5.21 %Z
SS 1C
5.18 %Z
SS 1B
5.23 %Z
Bus1A
0.48 kV
0.501 kV
Bus1C
0.488 kV
Bus1B
0.503 kV
1A Equiv LV Ld
1C Equiv LV Ld
1B Equiv LV Ld

Figure 11

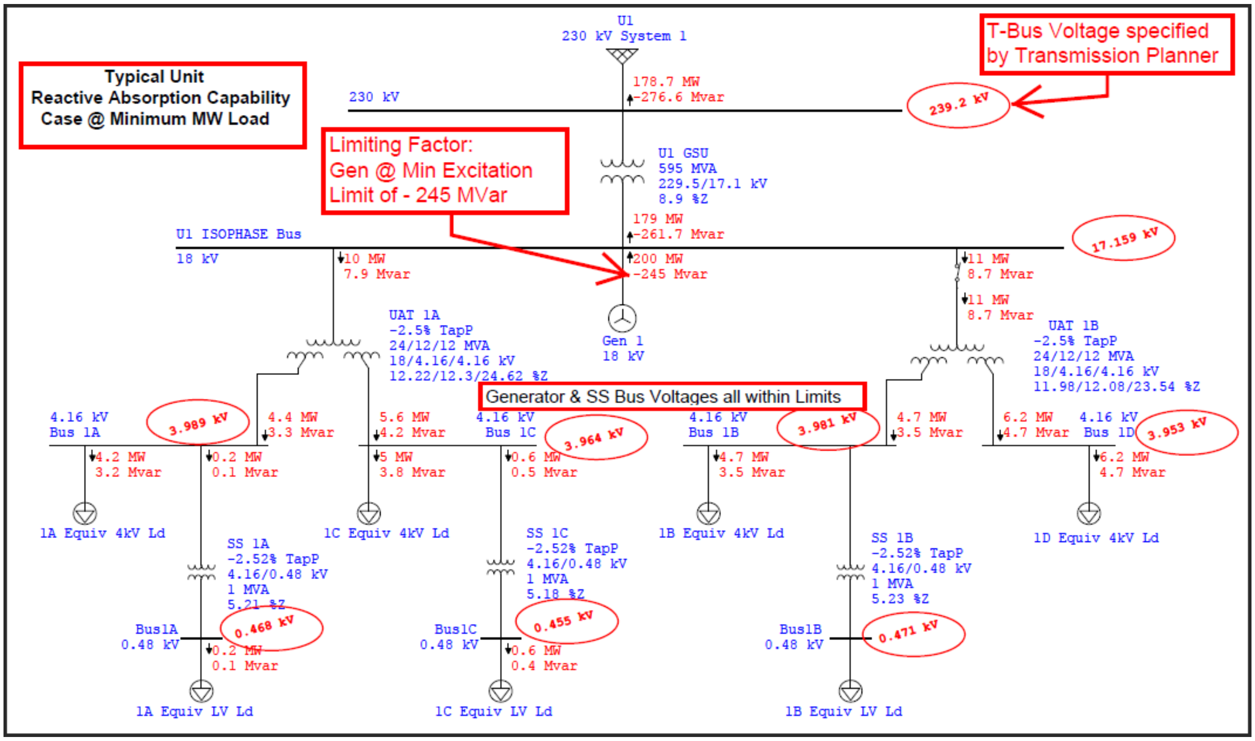


Figure 12

2. Clearly Document Limiting Factors

- Generator Reactive Power Capability
- Generator or Station Service (SS) Voltage Limit * (See Note below)
- Over Excitation Limiter (OEL), Volts/Hz Alarm / Limiter, Minimum Excitation Limiter (MEL)/Under Reactive Ampere Limiter (URAL)/Under Excitation Limiter (UEL)
- GSU MVA Limit, Bus Ampere Limit
- Other (specify)

* Note: It is important for the TP/TOP/RC to know the generator's actual operating voltage range capability to factor into their Transmission studies. This range is typically less than the generator's rated continuous range of 95-105% for units with station auxiliary buses powered directly from the generator terminal bus via fixed tap transformers.

As an example, for the typical unit evaluated above, the power flow model was used to determine the generator operating voltage range that would prevent exceeding the unit's station service bus voltage limits. These power flow simulations yielded the following results:

- With the unit operating at full load MW and its minimum generator voltage limit of 95%, the calculated station service bus voltages were within acceptable limits.
- With the unit operating at full load MW and its maximum generator voltage limit of 105%, the calculated station service bus voltages exceeded acceptable limits. The generator voltage had to be reduced to 103.7% of rated voltage to remedy this.

- With the unit operating at minimum load MW and its minimum generator voltage limit of 95%, the calculated station service bus voltages were within acceptable limits.
- With the unit operating at minimum load MW and its maximum generator voltage limit of 105%, the calculated station service bus voltages exceeded acceptable limits. The generator voltage had to be reduced to 102.4% of rated voltage to remedy this.

Thus, by determining and reporting the calculated generator voltage limits above, the Generator Entity is providing additional useful information to the TP/TOP/RC. Otherwise, they may assume this generating unit is able to operate at a generator terminal voltage range of 95-105%. It should be noted that generating unit operators typically monitor equipment voltage limits and receive alarms if these limits are exceeded. The typical operator response is to adjust the generator terminal voltage up or down, as appropriate, until the alarm is cleared.

Step 5 - Document Results for Reporting

1. Request Plant Operations Staff to Review & Provide Feedback.

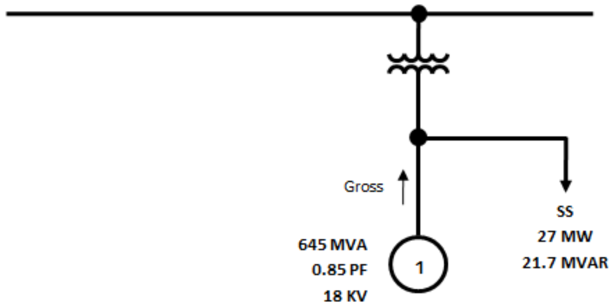
   Results of the Engineering Study should be reviewed with plant operations staff to verify there are no other known factors that can limit the unit's reactive power capabilities. Appendix E provides potential limiting factors that can be encountered during unit operation. Sharing this type of information with plant operations staff will help them identify and report reactive power capability limitations and their causes.

   Note: It is important that plant operators report limitations identified during operations to the appropriate Transmission Operator or other designated entity in the operations timeframe so near-term impacts on the transmission system can be determined (Refer to NERC Standard VAR-002-3). Limitations that are determined to be long term in nature should also be reported to the Transmission Planner so the Transmission Planner can factor the generator unit reactive power capability into Transmission Planning studies as appropriate.

2. Transmit Results to TP/RC

   The Gross and Net Reactive Power Capability should be reported. The generator upper and lower terminal voltage limits (discussed in Step 4) should also be reported, especially if the generator is unable to operate over its full rated generator terminal voltage range of 95-105%. The data may be reported to the Transmission Planner in a standard format. Results for the example unit are summarized below in a format (Figures 13 and 14) for reporting to Plant Operations Staff and Transmission Planning. The specific format can vary. However, the specific report format may have to meet MOD-025 and applicable Regional criteria when reporting results to Transmission Planning).

Plant 230kV System



Reactive Capability Results for Unit 1

Gross MW_{NSFL}	537 MW
Net MW_{NSFL} (Gross MW_{NSFL} – SS MW)	510 MW

Gross $MVAR_{OUT}$ Limit	**323 MVAR**
CONDITIONS @ LIMIT	
$MVAR_{OUT}$ Limitation	Gen Reactive Capability
230kV Bus Voltage	232.3 kV (101.0%)
Gen Voltage	18.02 kV (100.1%)
4160V Bus Voltage	4175 V (100.4%)
480V Bus Voltage	491 V (102.3%)

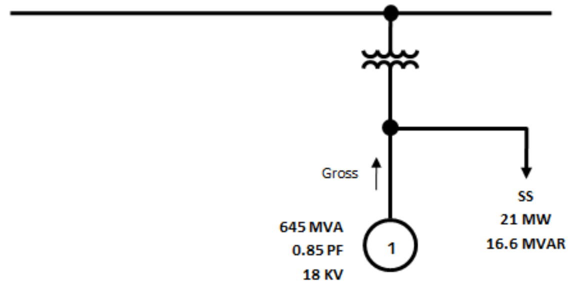
Gross $MVAR_{IN}$ Limit	**-172 MVAR**
CONDITIONS @ LIMIT	
$MVAR_{IN}$ Limitation	Min Excitation Limit
230kV Bus Voltage	239.2 kV (104%)
Gen Voltage	17.3 kV (96.1%)
4160V Bus Voltage	3963 V (95.3%)
480V Bus Voltage	455 V (94.8%)

Generator Upper Voltage Limit	18.7 kV (103.7%)
Generator Lower Voltage Limit	17.1 kV (95.0%)

Method of Verification: Engineering Assessment (Operational Data plus Analysis)
Date of Verification: __________

Figure 13

Plant 230kV System



Reactive Capability Results for Unit 1 @ Minimum MW Load

Gross MW_{NSFL}	200 MW
Net MW_{NSFL} (Gross MW_{NSFL} –SS MW)	179 MW

Gross $MVAR_{OUT}$ Limit	**420 MVAR**
CONDITIONS @ LIMIT	
$MVAR_{OUT}$ Limitation	Gen Reactive Capability
230kV Bus Voltage	232.3 kV (101.0%)
Gen Voltage	18.28 kV (100.6%)
4160V Bus Voltage	4259 V (102.4%)
480V Bus Voltage	503 V (104.8%)

Gross $MVAR_{IN}$ Limit	**-245 MVAR**
CONDITIONS @ LIMIT	
$MVAR_{IN}$ Limitation	Min Excitation Limit
230kV Bus Voltage	239.2 kV (104%)
Gen Voltage	17.16 kV (95.3%)
4160V Bus Voltage	3953 V (95.0%)
480V Bus Voltage	455 V (94.8%)

Generator Upper Voltage Limit	18.43 kV (102.4%)
Generator Lower Voltage Limit	17.1 kV (95.0%)

Method of Verification: Engineering Assessment (Operational Data plus Analysis)
Date of Verification: __________

Figure 14

It is recommended to also report the results in the D-curve format (Figure 15).

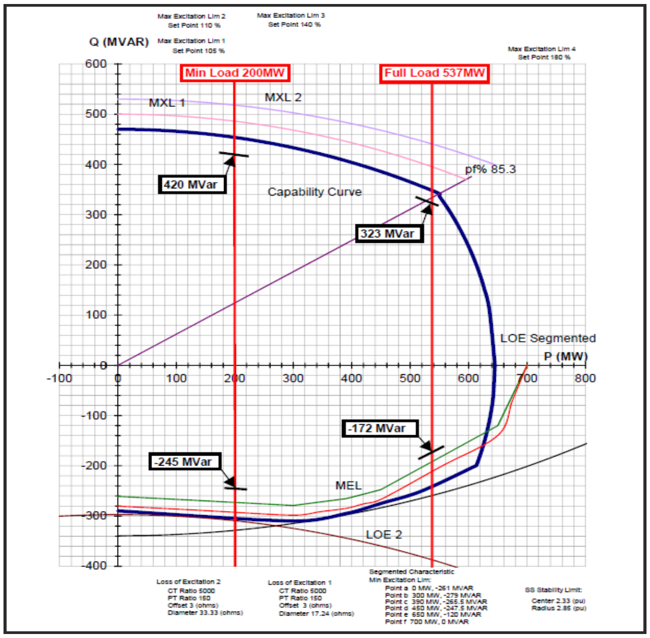


Figure 15

3.2 Transmission Planner Engineering Study

The Transmission Planner should develop a simple model of the generator, GSU, UAT transformer(s), and UAT load(s) to assess the voltage constrained reactive power limits of the generating unit as a function of transmission system voltage. This model may be used to verify the Engineering Study results provided by the Generator Entity or in lieu of Generator Entity Studies.

The following outlines an approach to determine generating unit reactive power limits for use in transmission system models.

1. Establish Generating Unit Power Flow Model
2. Validate Power Flow Model with Operational/Test Data
3. Perform Reactive Power Capability Simulations
4. Document Results for Reporting

Each of these steps is discussed in more detail below.

Step 1 - Establish Generating Unit Power Flow Model

The Transmission Planner should develop a simple model of the generator, GSU, UAT transformer(s), and UAT load(s). The following inputs are needed from the Generator Entity for development of the model:

- Unit Single Line Configuration/Drawings that show Generator, GSU and UAT connections
- GSU & UAT Electrical Characteristics including ratings, %Z, copper losses, core losses and tap settings

A simplified power flow model developed for a coal-fired generating unit with two UATs is shown below (Figure 16).

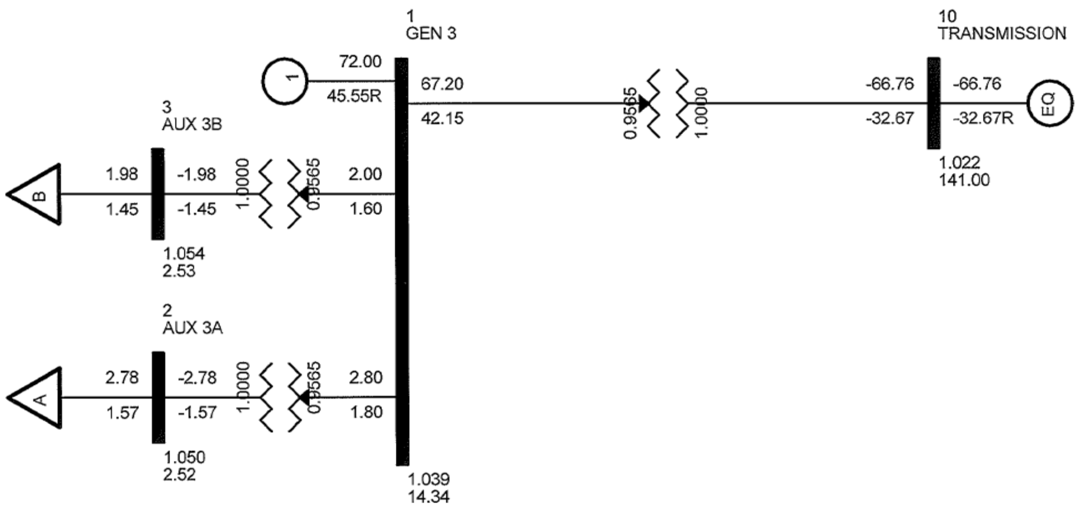


Figure 16

Step 2 – Validate Power Flow Model with Operational Data
The power flow model can be validated using the results using historical operating data. Data needed for validation of the power flow model are as follows:

- System Bus Voltage (high side GSU voltage) at the time of the test
- Generator Voltage and gross output (MW and MVAR)
- Station Auxiliary Bus Voltage and load (MW and MVAR)
- Flow from GSU into transmission system (MW and MVAR) – desirable but not absolutely necessary

It is recommended to obtain at least two sets of data at the following suggested operating points:

Set 1 – Typical high MVAR production with unit operating at or near normal or peak full load MW.
Set 2 – Typical high MVAR absorption with unit operating at or near minimum stable MW load.

- **Adjust Model Inputs to Simulate Actual Data**
  - Set Generator output (MW and MVAR) to actual values
  - Set Auxiliary load (MW and MVAR) to actual values
  - Set Transmission system voltage to actual value
- **Compare Simulated Results to Actual Data to Validate Model**

- Generator Voltage
- Auxiliary Bus voltage(s) and
- Flow from the GSU into the transmission system

- **Good Match Demonstrates:**
- Model is representative of actual generating unit electrical system operation
- Model can also be used to study other operating conditions (both generator and transmission system voltage sensitivities).

Step 3 - Perform Simulations to determine Reactive Power Capability Limits due to Voltage Constraints

The objective is to determine and provide reactive power limits throughout the MW output range of the generator and throughout an appropriate range of transmission voltages. It is recommended that the Generating Unit reactive power capabilities be determined at the following four points as a minimum:

- Leading (absorbing) reactive power capability at full generator gross MW load
- Lagging (producing) reactive power capabilities at full generator gross MW load
- Leading (absorbing) reactive power capability at minimum generator gross MW load
- Lagging (producing) reactive power capability at minimum generator gross MW load

It is recommended to determine the generating unit reactive power capability limits with the transmission system voltage at the scheduled value. If the generating unit reactive power capability limits are less than indicated by the D curve, additional simulations can be performed to determine the unit reactive power limits at other transmission system voltages. If the Transmission Planner does not have prescribed voltages for the sensitivity analyses, they can perform additional simulations at transmission voltages that produce generating unit reactive power limits that are comparable to the limits indicated by the D curve. Additional leading (absorbing) reactive power capability simulations should be performed for higher transmission voltages and additional lagging (producing) reactive power capability simulations should be performed for lower transmission voltages. These power flow simulations must demonstrate that generator and auxiliary bus voltages remain within acceptable limits at the leading and lagging reactive power limits.

To perform the necessary simulations, you need the following information from the Generator Entity:

- Generator maximum and minimum gross MW capabilities/limits
- Unit Auxiliary load (MW and MVAR) at each UAT connection
  Unit Auxiliary load may vary based upon MW output and unit auxiliary bus voltages. More accurate results will be obtained if this dependency is included in the simulations
- Generator and Unit Auxiliary Bus Voltage Ratings and Operating Limits
  The generator and unit auxiliary bus voltage limits modeled should include any constraints imposed by operating limits of all down-stream lower voltage equipment

NERC standard VAR-002 requires that most generators be provided a voltage schedule to follow. When transmission voltage is at the schedule value, the generator may be operating in either the leading or lagging region.

1. Set Transmission Voltage at the Scheduled Transmission Voltage
   - Set the generator output at the maximum gross MW output value
     - Adjust generator MVAR output to determine the maximum reactive power limit
     - Adjust generator MVAR output to determine the minimum reactive power limit
   - Set the generator output at the minimum gross MW output value
     - Adjust generator MVAR output to determine the maximum reactive power limit
     - Adjust generator MVAR output to determine the minimum reactive power limit

When the transmission voltage is above the scheduled value, the generator should be operating in the leading region, i.e. absorbing reactive power.

2. Set Transmission Voltage at a higher voltage*
   - Set the generator output at the maximum gross MW output value
     - Adjust generator MVAR output to determine the minimum reactive power limit
   - Set the generator output at the minimum gross MW output value
     - Adjust generator MVAR output to determine the minimum reactive power limit

When the transmission voltage is below the scheduled value, the generator should be operating in the lagging region, i.e. producing reactive power.

3. Set Transmission Voltage at a lower voltage*
   - Set the generator output at the maximum gross output value
     - Adjust generator MVAR output to determine the maximum reactive power limit
   - Set the generator output at the minimum gross output value
     - Adjust generator MVAR output to determine the maximum reactive power limit

*The transmission high and low voltages selected for the simulation should provide reactive power limits near the generators D-curve limits.

Step 4 – Document Results
The results of the simulations should be recorded and documented on a capability curve. This requires that you obtain the following information from the Generator Entity:

- Generator Manufacturer D-Curve
- Excitation Limiter Settings (MW and MVAR points that can be plotted on the D- Curve)

The results from the simulations for this generator are summarized below and shown below on the D-curve: This 13.8 kV generator includes two 2.4 kV auxiliary buses (Note: Vg on the diagram identifies reactive power limits that are constrained by generator terminal voltage limits. Va on the diagram identifies reactive power limits that are constrained by auxiliary bus voltage limits.). The generator terminal voltage limits are +/- 5% of the nominal generator voltage and the allowable auxiliary bus voltage range is 2,160 V - 2,530 V because of the 2,300 V motors connected to the buses. The applicable voltage limits must be obtained from the Generator Entity and the auxiliary medium voltage limits should consider the limitations of the downstream equipment. The reactive power output in this simulation is limited to 45.55 MVAR or less because of high voltage on the AUX 3B bus.

The sensitivity of the maximum and minimum reactive power limits at various transmission voltage levels can be determined through a series of simulations. The maximum and minimum reactive power limits were determined for this generator with the transmission system at 141 kV (the target scheduled value). The maximum was also determined with the transmission system voltage lowered to 139 kV and the minimum was also determined with the transmission system voltage increased to 144.9 kV (1.05 pu). The reactive power limits at the three selected transmission voltages are shown on the generator D-curve below (Figure 17).

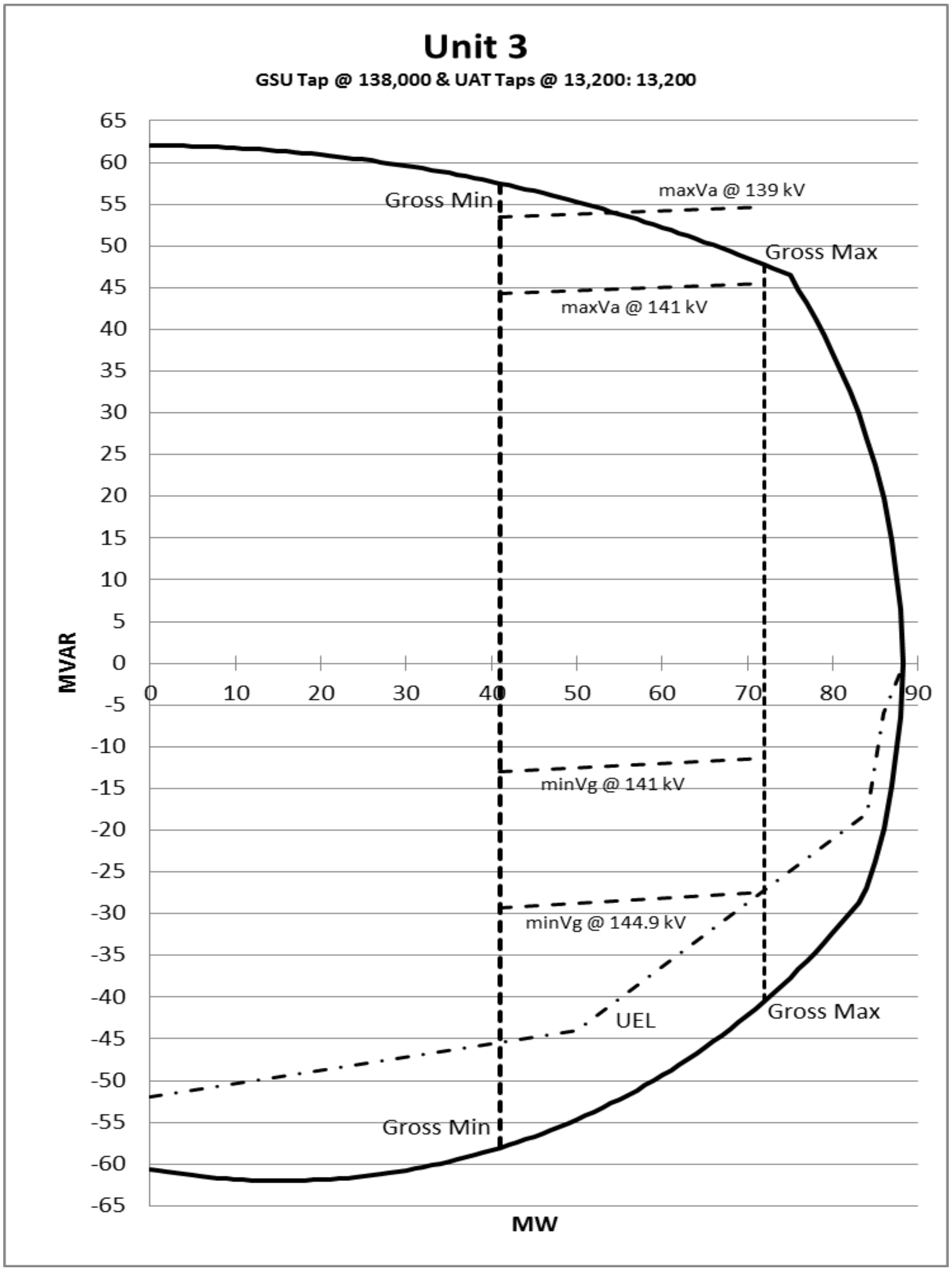


Figure 17

The voltage sensitivity shows that the ability of the generating unit to regulate transmission voltage improves when the transmission voltage deviates from the schedule. Therefore, setting Qmax and Qmin in the power flow model at the 141 kV schedule limits would be conservative and would provide pessimistic results when the transmission system voltage is different (higher or lower) than the scheduled value.

Section 4: Validation of Generating Unit Reactive Power Capability

Generating unit reactive power capability is required to meet system load, provide appropriate reserves and assure service reliability. This reactive power capability should be validated in a uniform manner that assures the use of realistically attainable values when planning and operating the system or scheduling equipment maintenance. The goal of the validation is to demonstrate that the stated capability for the generating unit can be obtained for continuous operation under expected operating conditions. To help achieve this goal, a reference document is provided herein for validating the reactive power capabilities of generating equipment. This reference document recognizes the necessity of exercising judgment in the determination of generating unit reactive power limits for transmission modeling purposes.

General

The Gross and Net Reactive Power Capability for generating units should be validated initially upon commissioning. The Gross and Net Reactive Power Capability should be reviewed and revalidated if warranted whenever there is a long term plant configuration change, following a major equipment modification, following changes in GSU transformer and/or station auxiliary transformer tap settings, following changes to the transmission system at or near the generating unit Point of Interconnection to the transmission grid, or as agreed to by the Transmission Provider and Generator Entity. Periodic re-validation is required by NERC in MOD-025-2. Specific schedules and validation method must satisfy NERC and applicable Regional criteria.

The Transmission Provider should provide each Generator Entity with the applicable MVAR limits used in the current Transmission Planning models to aid the Generator Entity in establishing "expected" capabilities for the Generator Entity's validation efforts.

The Gross and Net Reactive Power Capability (MVAR) should be validated at the gross continuous full load MW capability and the minimum gross MW load at which the generating unit is normally expected to operate. Reactive power capability determination should be coordinated between the Generator Entity and Planning Coordinator and/or Transmission Planner, as appropriate.

The Gross and Net Reactive Power Capability should be validated with the unit operated with all regularly used auxiliary equipment needed for normal unit operation in service.

Reactive power consumption by auxiliary facilities common among several units or an entire plant (for example, coal-handling or lighting) should be recorded and be prorated among the appropriate units as agreed between the Generator Entity and Planning Coordinator and/or Transmission Planner, as appropriate.

Discretion may be necessary when estimating station service for small, unmanned hydro and internal combustion stations, where station service may not be accurately metered and/or recorded on an hourly basis.

The Gross and Net Reactive Power Capability should be determined separately for each generating unit in a power plant if the maximum net output of each unit is independent of the others. Two (2) or more units in a single station and/or two (2) or more stations whose capability is limited by common elements and/or commonly assigned staff should have their capabilities determined recognizing the limitation of those common elements [e.g., staffing, steam headers, stacks and other boiler auxiliaries, condenser cooling equipment (e.g., spray modules, pumps, screens, inlets, discharge canals, cooling towers), common river flows, head and tailrace water levels, common penstock, watershed, etc.]. This includes combined cycle units. This also includes unit configurations where multiple generators share a common 2-winding GSU transformer. Each unit should be assigned a rating by apportioning the combined plant(s) capability among the affected units.

4.1 Methods

Validations of reactive power capabilities of generating units have been attempted using the following methods:

- Staged unit reactive power capability testing
- Documentation and review of unit operational history data

The intent of this reference document is not to promote a particular method. Instead the goal is to identify merits and limitations of each method to help identify best practices that will yield confidence in the reactive power capability information used in planning and operational studies.

4.2 Staged Testing

Reactive power capability stage (actual unit) testing and reporting of test data and results must be performed in accordance with NERC Standard MOD-025-2 and applicable Regional criteria. This document provides additional guidance to the GO, GOP, TOP, TP, and RC to facilitate the testing process. The intent is to achieve the maximum possible reactive power production and/or absorption during the testing while maintaining system reliability and protection of the generating unit(s) or synchronous condenser(s) under test and adjacent units or other reactive power resources used to facilitate the testing.

Validating reactive power capabilities by testing should be an engineering assessment to determine the expected reactive power capability of the unit including potential limiting factors. This assessment should include a PRC-019 review of excitation system limiters and protection settings prior to testing. Review of the design or calculated settings and the as-left settings from excitation system field test reports is recommended.

Review reactive power capability test procedures, guidelines, precautions, and limitations with generating plant operators and Transmission Operators. This should include:

1. Purpose of testing and the expected unit reactive power capabilities
2. Review of generating unit equipment ratings and operating limits. This should include thermal (MVA, ampere, temperature) and voltage limits for the following:
    - Generator
    - GSU transformer
    - Generator bus
    - Generator breakers and disconnect switches as applicable
    - Unit auxiliary transformers

- Unit auxiliary buses (include max and min voltage limits)
- Other as appropriate

3. Identification of any known equipment limitations that could impact unit reactive power capabilities. Examples are as follows:
   - Field current/heating limits due to shorted rotor turns;
   - Excessive turbine-generator vibration;
   - H_2 cooling system problems (H_2 pressure limitations, H_2 purity issues, etc.);
   - Plugging or fouling of heat exchangers used for generator inlet air cooling (air cooled generators);
   - GSU transformer cooler problems (plugged or dirty heat exchangers, cooling pumps or fans out of service , etc.);
   - Generator bus cooling problems, hot spots, etc.;
   - Generator or station service bus voltage limitations;
   - Abnormal station service bus alignments;
   - As-built excitation limiter settings that are more restrictive than the calculated settings;
   - Any other limits identified during plant operation.
4. MW and MVAR ramp rates allowable for the unit to be tested and other units that may be used to support the test unit

Prior to testing, perform additional assessments as appropriate to determine if operating at the expected reactive power capabilities will cause any plant or power system risks. Coordination between the Generator Entity and the Transmission Provider is required to assess these risks.

The Generator Entity and Transmission Provider should seek support and coordinate reactive power testing with the Transmission Operator in order to safely achieve maximum possible unit VAR production/absorption during the testing. It is expected that, for many generating units, the full reactive power capability available for grid voltage support will not be demonstrated during testing. This is primarily due to voltage limitations or constraints imposed by the transmission system interconnection. This is further explained within this reference document and supported by industry experience with staged testing. See Appendix H which provides results of a survey on experience with staged testing in the SERC region (Results may differ in other Regions and among Balancing Areas.).

The Transmission Operator and/or Reliability Coordinator should establish system bus voltage limits for each test condition. These limits may exceed the normal voltage schedule to allow the unit under test to produce or absorb the desired MVARs. These limits should not be exceeded during the testing unless approved by the Transmission Operator and/or Reliability Coordinator based on system conditions at the time of testing.

The Generator Entity and Transmission Provider should agree that the risks of operating the plant at the expected reactive power capabilities and transmission bus voltages are acceptable.

If the risk of operating the plant at the expected reactive power capabilities is not acceptable:

- An intermediate value (between recent historical data and maximum values) should be attempted to validate the reactive power capabilities. Determination of an intermediate value should be coordinated between the Generator Entity and the Transmission Provider. Additional engineering evaluation may be appropriate to verify expected reactive power capabilities are achievable.
- Otherwise, the test should be rescheduled for a time when operation at the expected reactive power capabilities and transmission bus voltages would be acceptable.

The Transmission Operator may have to manipulate other reactive power resources in the area to facilitate the testing and to achieve the desired MVAR levels for the unit under test. This may include transmission capacitors, transmission reactors, static VAR compensators, load tap changers, and/or other generating units. This will typically constitute an abnormal configuration and operating condition. Caution should be exercised to avoid inadvertent tripping of the unit under test or other reactive resources during the test period. Not taking such measures is likely to cause max-lagging tests to occur at high voltage and max-leading at low voltage, i.e. opposite the situation for actual voltage control, which may not constitute a credible verification of reactive power resources during the test period.

Reliable communication should be established and maintained between the Generator Operators, Transmission Operators, and others as needed for the test duration.

The AVR and PSS, as applicable, should be in service for the unit being tested and adjacent units in the same plant. The Transmission Operator should confirm the AVRs and PSSs are in service for other units as appropriate.

Overexcited reactive power capability validation should be conducted for a minimum of one hour. Data should be recorded for the duration (15 minute intervals minimum recommended) and at completion of the test.

Data for the under excited reactive power capability validation may be recorded as soon as a limit is encountered.

Steady real and reactive power output should be maintained during the data collection intervals.

For hydrogen-cooled generators, the hydrogen pressure should be at the maximum normal operating pressure. If the maximum design hydrogen pressure cannot be achieved, then the reason for this condition should be documented and the appropriate Generator Capability Curve should be used.

If the full reactive power capability available for grid voltage support cannot be demonstrated during testing, additional engineering evaluation as described in Sections 3.1 and 3.2 can be used to verify expected reactive power capabilities are achievable.

Recording of Test Data

The following are typical test data that should be recorded:

1. Date of test, test start and test end times, and times each data set is taken.
2. Voltage schedule provided by the Transmission Operator, if applicable.
3. System interconnection bus actual kV.
4. GSU transformer high voltage winding kV (if significantly different from Item 3) and output in MW and MVAR (or Amps and PF), if available.
5. GSU transformer winding and oil temperatures.
6. Generator gross kV, MW, MVAR (@ generator terminals) and applicable operating voltage limitation.
7. Generator field current and voltage.
8. Exciter field current and voltage, where applicable.
9. Generator bus fed (power potential transformer) excitation system loading in MW and MVAR (or Amps and PF), where applicable.
10. Each medium voltage station auxiliary bus kV and load in MW and MVAR (or Amps and PF) and applicable operating voltage limitation.
11. Each instrumented 480 V and/or 600 V station auxiliary bus kV and load in MW and MVAR (or Amps and PF) that may limit the overall unit capability.
12. Ambient air temperature and humidity.
13. Generator cooling parameters as applicable:

   a. Stator winding temperatures
   b. Rotor or field winding temperature.
   c. H_2 pressure for hydrogen cooled generators.
   d. Cold gas temperature for hydrogen cooled generators.
   e. Inlet air temperature for air cooled generators.
   f. Cooling water inlet temperature.
   g. Other equipment as applicable.
14. GSU and auxiliary transformer voltage ratings (or ratios) and tap settings.
15. Limiting factors for each VAR data point tested. These could include but are not limited to the following:
   a. Transmission system voltage limit.
   b. Generator reactive power capability curve thermal limit (specify: stator, rotor, or end-iron limit).
   c. Minimum or under excitation limit (MEL, UEL, URAL, etc.).
   d. Field current limit.
   e. Generator voltage limit.
   f. Auxiliary bus voltage limit (specify worst case medium or low voltage bus)
   g. Generator vibration.
   h. Generator temperature limit (specify: stator winding temperature, rotor temperature, inlet or outlet air temperature, etc.).
   i. H_2 pressure restriction.
   j. Shorted rotor turns.
   k. GSU transformer MVA limit.
   l. GSU transformer winding or oil temperature limit.
   m. Generator bus temperature limit.
   n. Other (specify).

Notes:

1) The intent in reactive power capability testing is to use available plant instrumentation.
2) If instrumentation is unavailable, this should be noted and the missing quantities measured with portable instruments, calculated, or estimated as appropriate to satisfy NERC and Regional criteria.
3) Instrumentation that appears to be inaccurate should be identified and reported to plant staff for inspection and calibration.
4) Refer to MOD-025-2 and applicable Regional criteria to ensure all data requirements are met.

4.3 Operational History Data

Starting from the existing plant power flow model in the grid planning software, the Generator Entity or Transmission Planner should develop study cases for validation of the power flow model of the Generating Unit to the Grid for the operating MW points to be studied (P_{max} or $P_{full\text{-}load}$ and P_{min}) and develop expected results. For more information, refer to Sections 3.1 and 3.2. This engineering assessment should be compared to normal plant operational data to verify the assessment assumptions and results.

   a. Inputs include:
      - Transformer taps settings calculations

- Expected maximum reactive power support based on generator design capability and PRC-019 data
- Aux system voltage limitations and the load (MW and MVAR) expected at the two operating points (Some Planners ask for linearization constants relating gross to net MWs)

b. The Planner or Generator Entity should obtain operating data with the generating unit operating as close as possible to the planning cases to be reviewed including:
   - Generator MW, MVAR, Voltage
   - High Side of GSU MW and MVAR and Grid Voltage
   - Aux System Bus MW, MVAR and voltage (both the medium and low voltage systems should be considered; e.g., 600 V and 480 V)

c. Perform model simulation cases and compare results to the operating data

d. Develop a plot of MVAR operating data vs. the capability curve and PRC-019 coordination calculation

Use of operational data for validating the Generator Entity and Transmission Planner models is addressed in Sections 3.1 and 3.2. However, other methods of using operational data can be used to help verify the model(s) reflect a generating unit's reactive power capabilities under various operating conditions and, therefore, aid the Transmission Planner in selecting the best model parameters and limitations for use in planning and/or operational studies. As examples, a number of plots are provided below to illustrate the use of operating data to evaluate the historical reactive power output range of an actual unit.

Example 1 (Figure 18) - The average hourly MW and MVAR output of a typical generating unit is shown in the chart below. For this unit, Transmission Planning revised the unit's reactive power capability limits based upon this data and discussions with the Generator Entity.

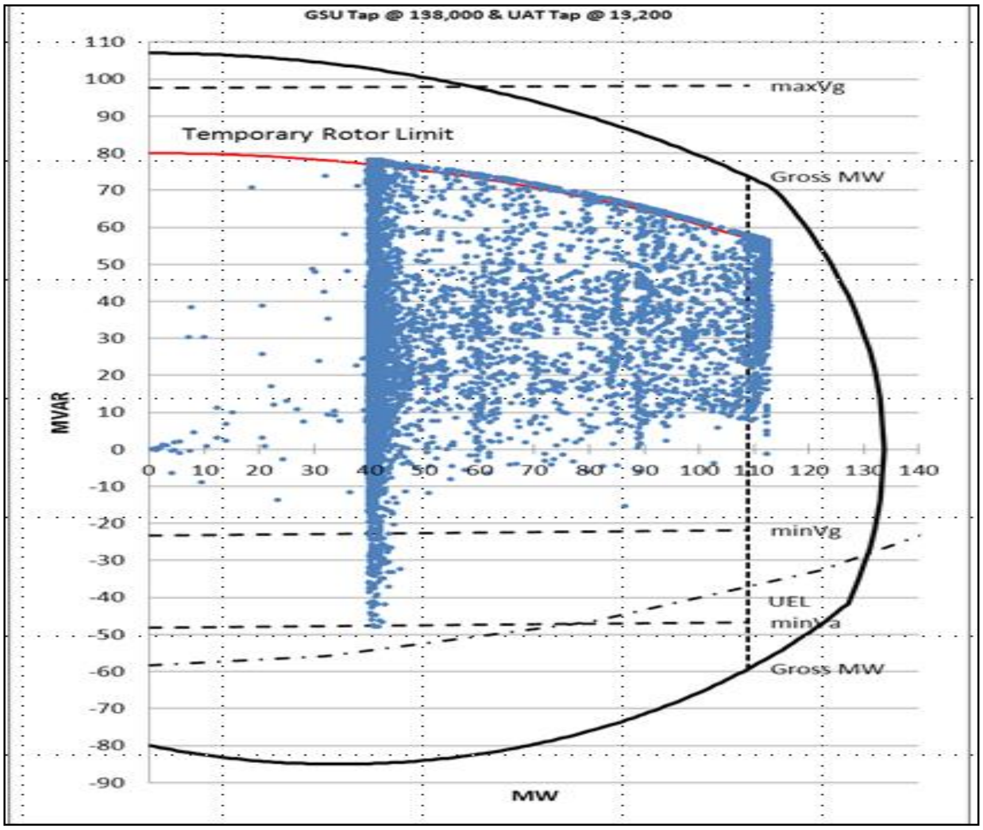


Figure 18

Example 2 (Figure 19) – The Unit is scheduled to hold a target transmission system voltage of 141 kV. The average hourly MW and MVAR output of the unit when the transmission system voltage was between 140.5 kV and 141.5 kV is shown in the chart below. In this chart, one can observe that the unit's maximum MVAR output is consistent with the value identified due to auxiliary bus voltage limits.

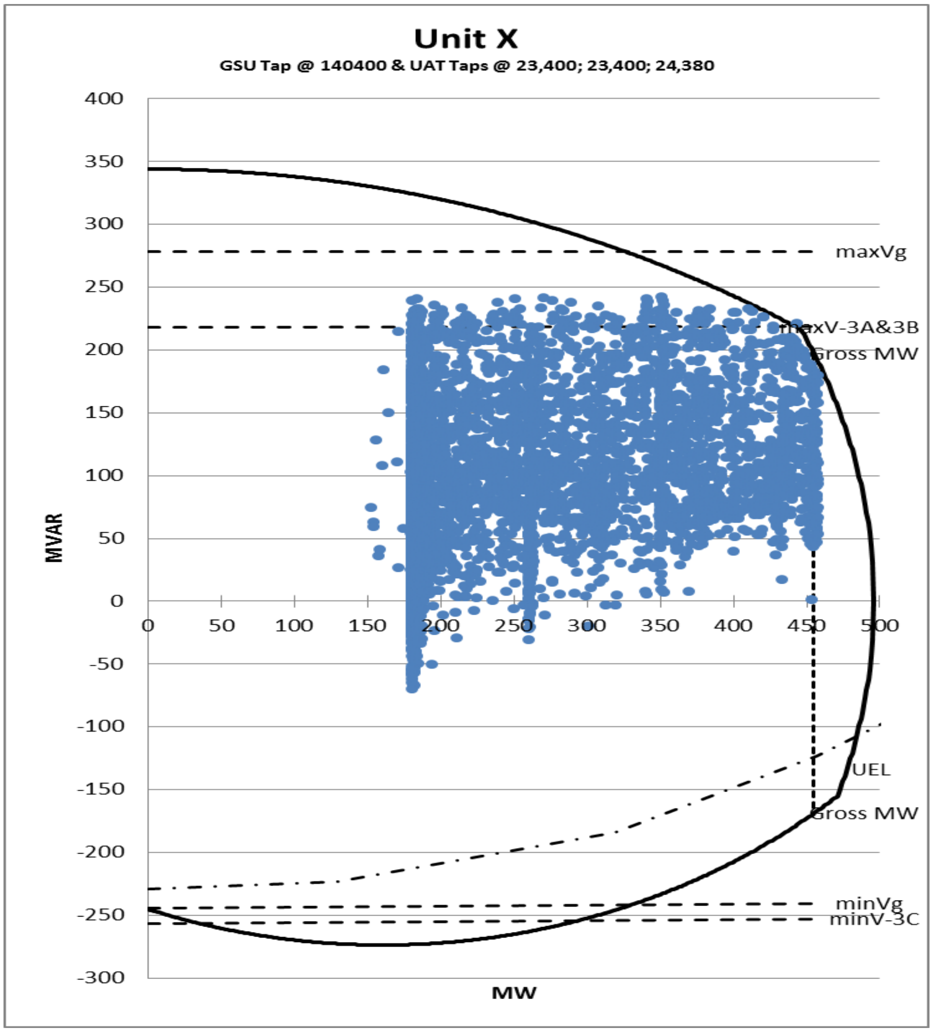


Figure 19

Example 3 (Figure 20) – The Unit did not maintain the target transmission system voltage of 141 kV for several hours during the year. The average hourly MW and MVAR output of the unit when the transmission system voltage was below 140.5 kV is shown in the chart below. When transmission voltage is depressed, the units maximum MVAR output exceeds the value identified due to auxiliary bus voltage limits at 141 kV transmission system voltage.

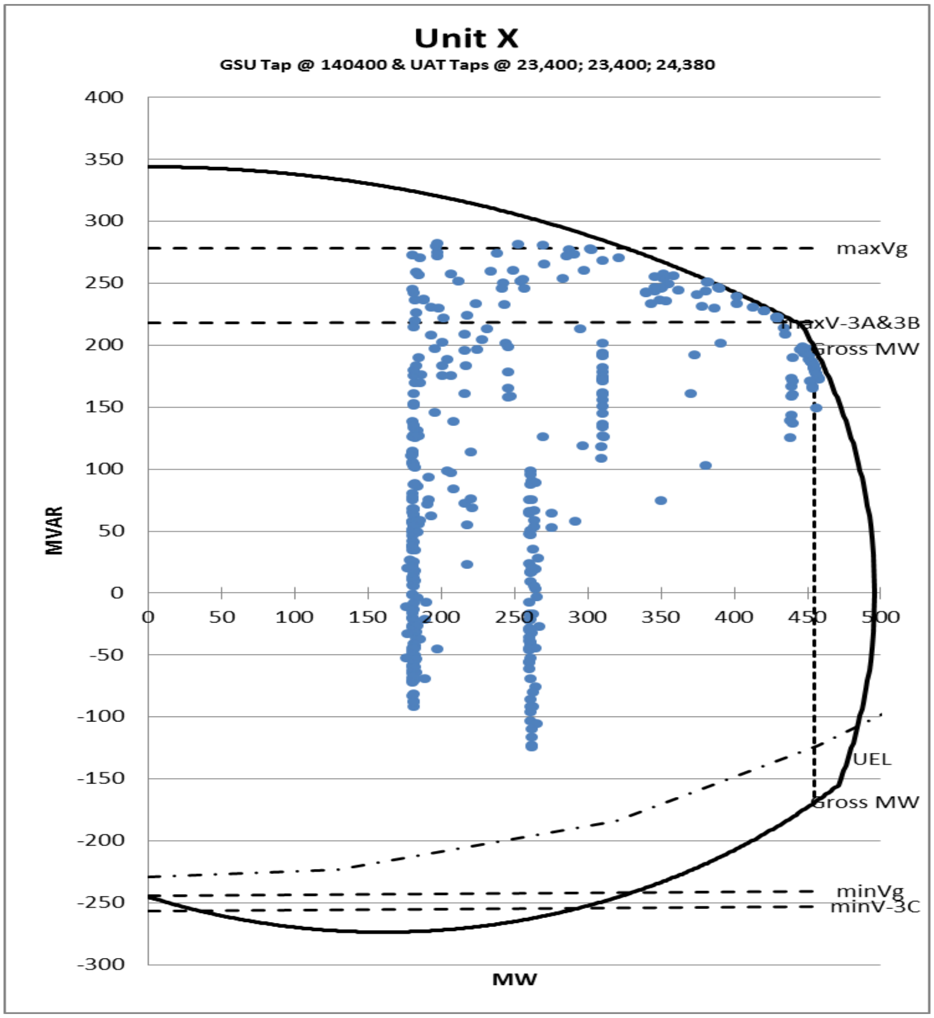


Figure 20

One can conclude from this type of data that the reactive power capability of a typical "generating unit" varies with changing system conditions and is likely not coincident with the manufacturer's D-curve for the "electrical generator." What these plots illustrate is the importance of the aforementioned factors when establishing generating unit reactive power capabilities for use in transmission planning and operations.

It is important to note that such operating data can be used in lieu of, or in conjunction with, staged testing and/or power flow simulations to verify a unit's actual capability under varying system conditions. Depending on the actual transmission system and generating unit, this data may or may not fully indicate what the unit is capable of doing under extreme system voltage conditions which are seldom encountered. In such cases, additional engineering study may be needed. Additional testing may also be beneficial if system conditions can be selected that facilitate the specific test objective(s). Both methods have benefits and potential drawbacks.

4.4 When Repeating Validation Performance is needed

Recognizing MOD-025-2 requires testing at a minimum of every 5 years, Transmission Planners should be consulted and post modification revalidations should be considered anytime there is a material change to the generating unit or transmission grid which might affect Real or Reactive Output Capability. Material changes include, but are not limited to

1. Generator Rewinds with MVA Uprates
2. Turbine replacements
3. Main Power train equipment replacements
4. Changes in GSU transformer, UAT, and/or other SST tap settings
5. Significant load additions made to plant aux electrical systems
6. Degradations of equipment support systems which will be in place for more than a year (e.g., transformer, GCB, generator or bus cooler problems, rotor shorted turns, etc.). Note that the reporting of these degradations are required by standards as soon as they are recognized for consideration of impact to operating models.
7. Main power train relay replacements
8. AVR/Exciter settings changes and replacements (limiter and protection element settings should be addressed in PRC-019 documentation)
9. Reconfiguration or reinforcement of the transmission grid that weaken or strengthen the system as seen by the generating unit

Validations should be <u>**reviewed**</u> by Generator Entities periodically for confirmation that no significant plan changes or equipment degradation have occurred since the last formal evaluation. (MOD-025-2 requires the re-validation every 5 years. Regional requirements may be more frequent.)

Appendix A: Understanding Generator and Generating Unit Reactive Power Capability

1. Generator Reactive Power Capability

"Generator" reactive power capability relates to the thermal limitations of the generator itself and is the level of reactive power that is available at the terminals of the generator if system voltages are such that full reactive power support is demanded. Limitations other than the OEM generator design, such as high or low transmission, generator or auxiliary equipment voltage; impedance and strength of the point where the generating unit is interconnected to the transmission grid are not reflected in the OEM generator reactive power capability curve.

The major factors impacting the electrical generator's reactive power capability at any point in time are depicted on the generator's reactive power capability curve (also known as D-curve). These factors are:

- MVA rating of the generator (also known as stator/armature thermal or current limitations);
- Rotor main field winding thermal or current limitations;
- Stator end core thermal limitations;
- Coolant temperatures (e.g., hydrogen pressure of steam units, cooling ponds, efficiency of stator coolers, ambient temps for air cooled machines, etc.);
- Actual generator MW output versus the MW rating of the generator at rated power factor (PF).

Appendix A provides typical manufacturer's generator D-curves for hydrogen cooled and air cooled machines.

It is important to recognize that the "generator" reactive power capability curve only represents the capability of the electrical generator itself. The manufacturer generator reactive power capability curve or D-curve does not take into account: a) the design of the auxiliary power system and its coordination with the generator terminal voltage; b) the GSU transformer electrical characteristics; c) the strength of the transmission system to which the generator is connected; d) the transmission operating voltage and coordination with the GSU transformer tap setting; and e) generator protection system settings. These five factors will affect the "generating unit" reactive power capability. The distinction between the "Generator" reactive power capability and the "Generating Unit" reactive power capability must be understood, evaluated and reported so the generating unit can be modelled correctly in Transmission Operations and Planning studies.

1a Coordination of Protection & Limiter Elements with Generator Capability

A first step in determination of the "generating unit" reactive power capability is to develop a P-Q plot of the generator D-curve modified with the applicable generator and excitation limiter and protection device setting curves consistent with NERC PRC-019 requirements. These typically include but are not limited to the following:

- Calculated Steady-State Stability Limit (SSSL) Curve
- Limiter Curves (UEL, OEL, V/Hz and Stator Current Limiters)
- Loss of Excitation Relay (40) Settings

The plot below (Figure 21) is an example from NERC Standard PRC-019-1 and shows that some limiter and protection device settings are more limiting than the generator D-curve. Typically, this is the under (or minimum) excitation limiter. Other devices, such as loss of excitation (or loss of field) protection settings can encroach on the lower segment of the D-curve. These settings are critical for protection of the generator from being severely damaged due to excessive stator end-iron heating, loss of excitation, or coming out of step (loss of synchronism) with the system.

Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency

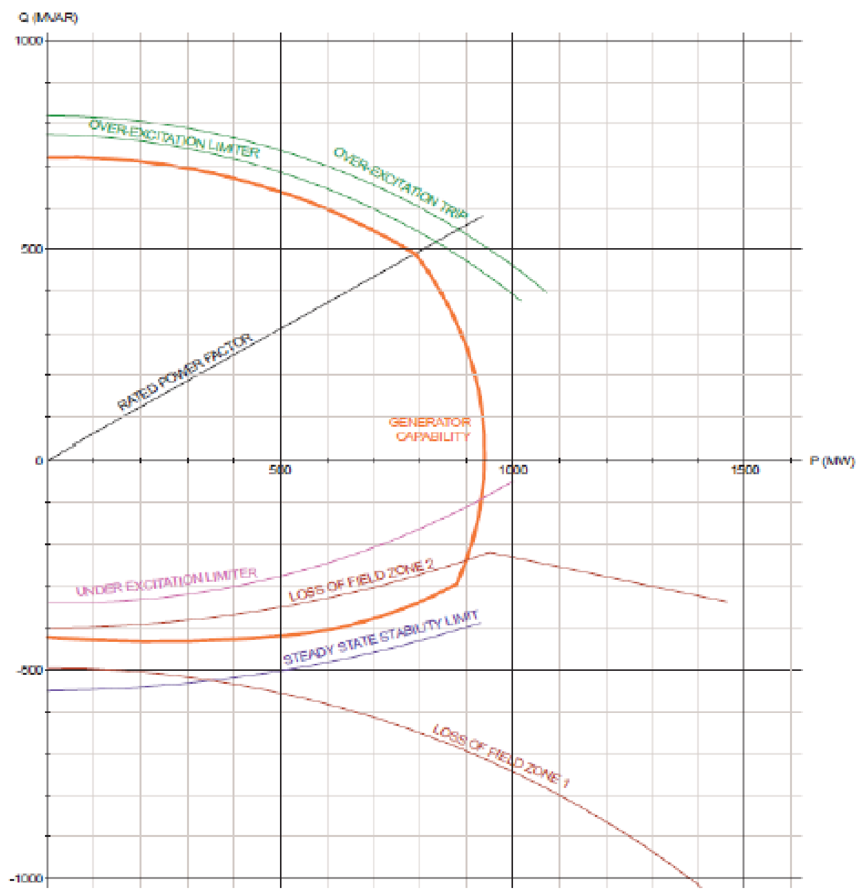


Figure 21

Notes:

1. The typical plot above shows a single generator reactive power capability curve for a specified set of conditions (e.g., operation at rated terminal voltage, frequency, MVA, and H_2 pressure for a hydrogen cooled generator).
2. All generators do not have the same compliment of protection or limiter devices or functions. Therefore, a generator-specific plot is recommended for each generator.
3. Some digital excitation systems may have over excitation or maximum excitation limiter functions that can be programmed to re-calibrate based on H2 pressure input. Availability depends on the age and manufacturer of the excitation system.

4. Some digital excitation systems may have under excitation or minimum excitation limiter functions that shift as a function of the actual generator terminal voltage. Availability depends on the age and manufacturer of the excitation system.

2. "Generating Unit" Capability

It is important to recognize that the reactive power limits discussed in Sections 3.1 and 3.1.a only represent the capability of the electrical generator itself with its applied generator, excitation system and protection limits. The capability of an electrical generator interconnected to the electrical power system is determined by the complete "generating unit" configuration including the generator step-up (GSU) transformer, the generating unit auxiliary system, and other factors. "Generating unit" reactive power capability, at any given set of system conditions and unit MW output, can be significantly less than the thermal capabilities of the generator defined by the generator D-curve. The generating unit reactive power capability relates to the amount of support available for grid voltage control and is influenced by the following:

- Transmission system voltage levels and transmission system short circuit MVA levels;
- GSU transformer factors including impedance (MVAR losses) and voltage tap settings;
- Station auxiliary transformer tap settings, loads (MW and MVAR or PF), and related auxiliary bus voltage limitations;
- Thermal or ampere ratings of equipment between the generator and the point of interconnection (bus, breaker, switch, GSU transformer, etc.), if these are not rated to support the full generator MVA rating.

When an electrical generator is interconnected to the electrical power system through a GSU transformer to establish the "generating unit" configuration, the generating unit's reactive power capability is significantly impacted by the GSU transformer's MVA rating, internal impedance, winding voltage ratio (tap setting), and the operating voltage range of the system bus connection at the high voltage side of the GSU transformer Electrical system studies are typically performed during initial plant planning and design to select and optimize these critical GSU transformer parameters for the specific generating unit being designed. This is necessary to ensure acceptable voltage and reactive power support for the system. Appendix B provides details on how generating unit reactive power capability is impacted by the GSU transformer and provides examples of the impacts due to different GSU transformer tap settings.

Generator voltage operating limits provided by OEMs are typically 95 to 105% of the generator nameplate voltage rating without de-rating the reactive capability of the machine. Exceeding these voltage limits may cause damage to the generator and should not be intentionally exceeded in meeting grid voltage schedule requirements. However, wider operating voltage bands may be permissible with the appropriate MVA rating de-rate.

While generators are designed to operate between 95% - 105% of rated (nameplate) terminal voltage on a continuous basis, many generators could have more restrictive operational terminal voltage limits due to the fact these generators supply power to station auxiliary system equipment directly from the generator through one or more Unit Auxiliary Transformers (UATs) as shown by Point B in Figure 22 below.

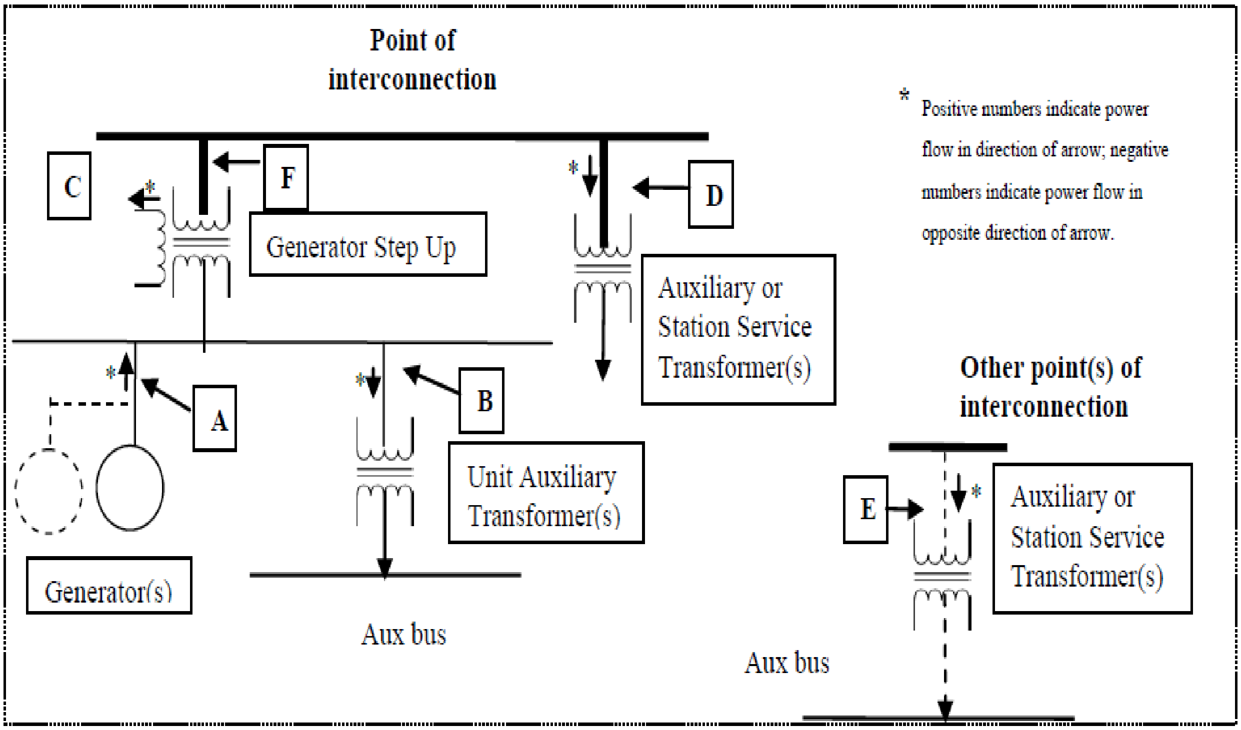


Figure 22 - Diagram From MOD-025-2

The medium and low voltage station buses and auxiliary equipment also have voltage limits that must be observed for reliable operation of the generating unit and the auxiliary systems. Some generating units employ load tap changing transformers in their auxiliary systems to minimize or eliminate these impacts on the generator operating voltage range and reactive power capabilities. However, most generating plant station auxiliary systems employ fixed tap transformers. There are system design considerations and constraints other than voltage (station bus loadings, short circuit limits, impact loadings, economics, etc.) that must be observed during plant design. Due to these and the use of fixed tap transformers, the station auxiliary voltage limits when reflected upstream through the UAT(s) can limit the generator operating voltage to a range less than 95 - 105% of rated terminal voltage which are the generator design limits (Reference: IEEE C50.13). The generator terminal voltage at any output is dependent on the GSU transformer (nominal voltages, impedance and tap setting) and the transmission system voltage at the time.

For some Generator Entities, auxiliary bus voltage limits are typically based on 110% of motor nameplate voltage (per NEMA MG-1) and between 92.5% and 95% of nominal bus voltage. [The Generator Owner (GO) is ultimately responsible for establishing these bus voltage limits to ensure safe and reliable operation of the station auxiliary system over a wide array of operating conditions.].

The Generation Entity should consider any auxiliary power system limitations, if applicable, when defining the expected unit capability (Qmax and Qmin) and allowed voltage operating bands to be reported for Transmission Load Flow Models, as required by new NERC MOD-032 (was MOD-010).

If there are more restrictive voltage limitations due to auxiliary equipment, the GO should define that as a reduced allowed generator voltage band. These restrictions can be defined with system voltage at nominal, minimum scheduled and maximum scheduled grid voltage. This would permit the planning and operating models to respect those limitations when performing Planning and Operating analyses. It is suggested any known limitations due to the equipment fed from these busses be monitored appropriately by plant instrumentation and alarm limits, such that these will be known to the plant operations staff during abnormal grid voltage conditions is applicable.

For example, nuclear site generator bus voltage operating limits may be restricted tighter than the 105% maximum for the generator due to NRC degraded grid design requirements. Another example is a typical legacy fossil unit whose generator bus voltage operating range can limited to 5-6% instead of the 10% range for the generator itself. This can be caused by a mix of 550V and 575V motors on the low voltage buses which occurred due to changes in the industry standards for low voltage motors.

Reactive power limits due to voltage constraints on the generator and the unit auxiliary system and the dependence on transmission system voltage can be illustrated on the capability curve. The figure below (Figure 23) shows an augmented Generator D-curve Reflecting Generator and/or Auxiliary System Voltage Limitations attributable to High or Low Transmission POI Voltages.

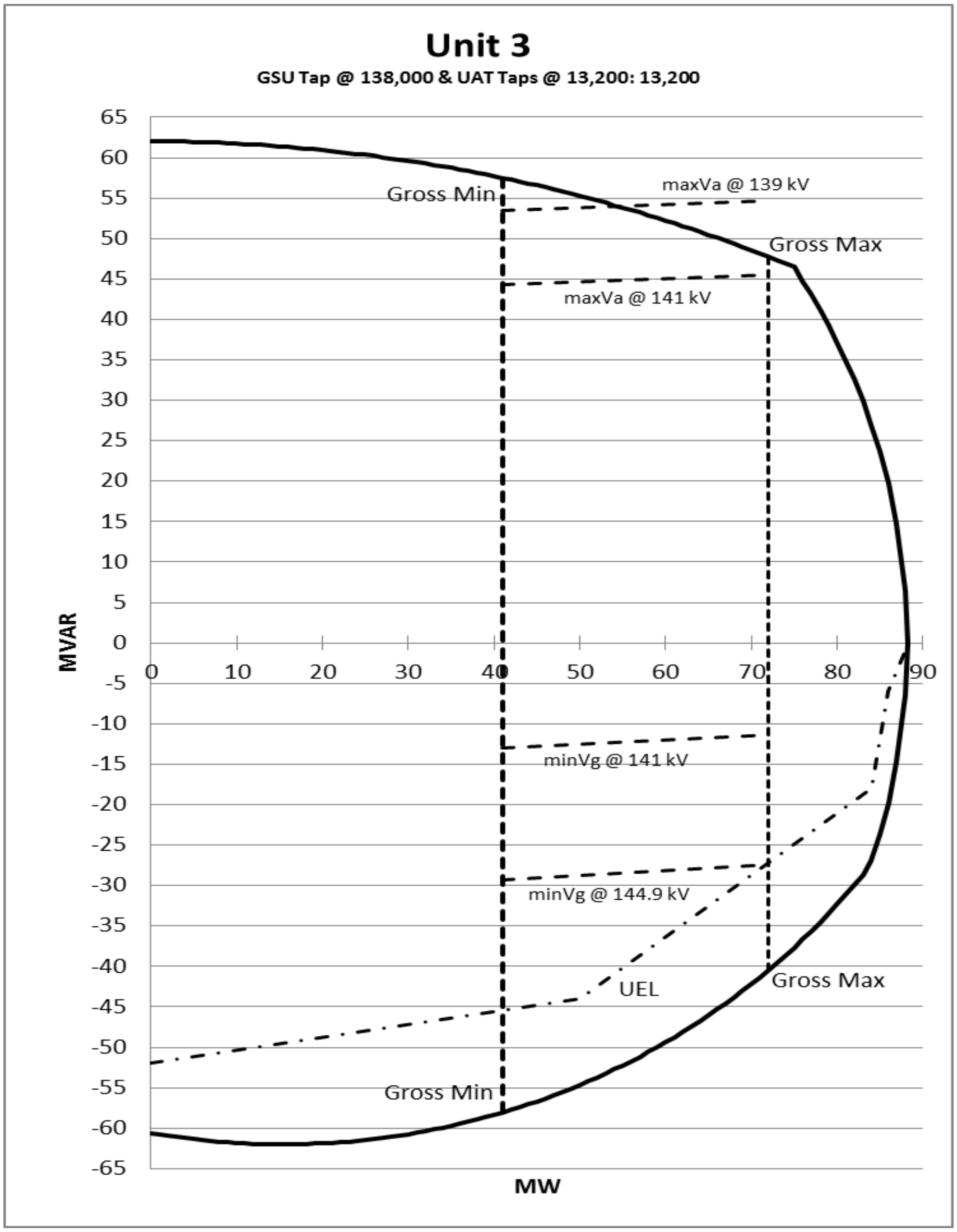


Figure 23

The sensitivity of the maximum and minimum reactive power limits at various MW output levels and transmission voltage levels can be determined analytically or through a series of simulations. The modeling and simulations required to establish the reactive power limits due to generator, transmission and/or auxiliary system voltage constraints are discussed in Section 3.

Appendix B: Generator D-Curve Examples

Hydrogen Cooled Generator

MVA, MW, and MVAR capability are dependent on the operating H2 pressure. For the example generator below (Figure 24), the rated or maximum operating pressure is 45 PSIG. For new and properly maintained generator, operation at rated H2 pressure can be expected to enable the generator to operate at its full capability. H2 pressure limitations can occur at times due to condition of the H2 cooling system or H2 leakage and can, thus, potentially limit the generator's reactive power capability.

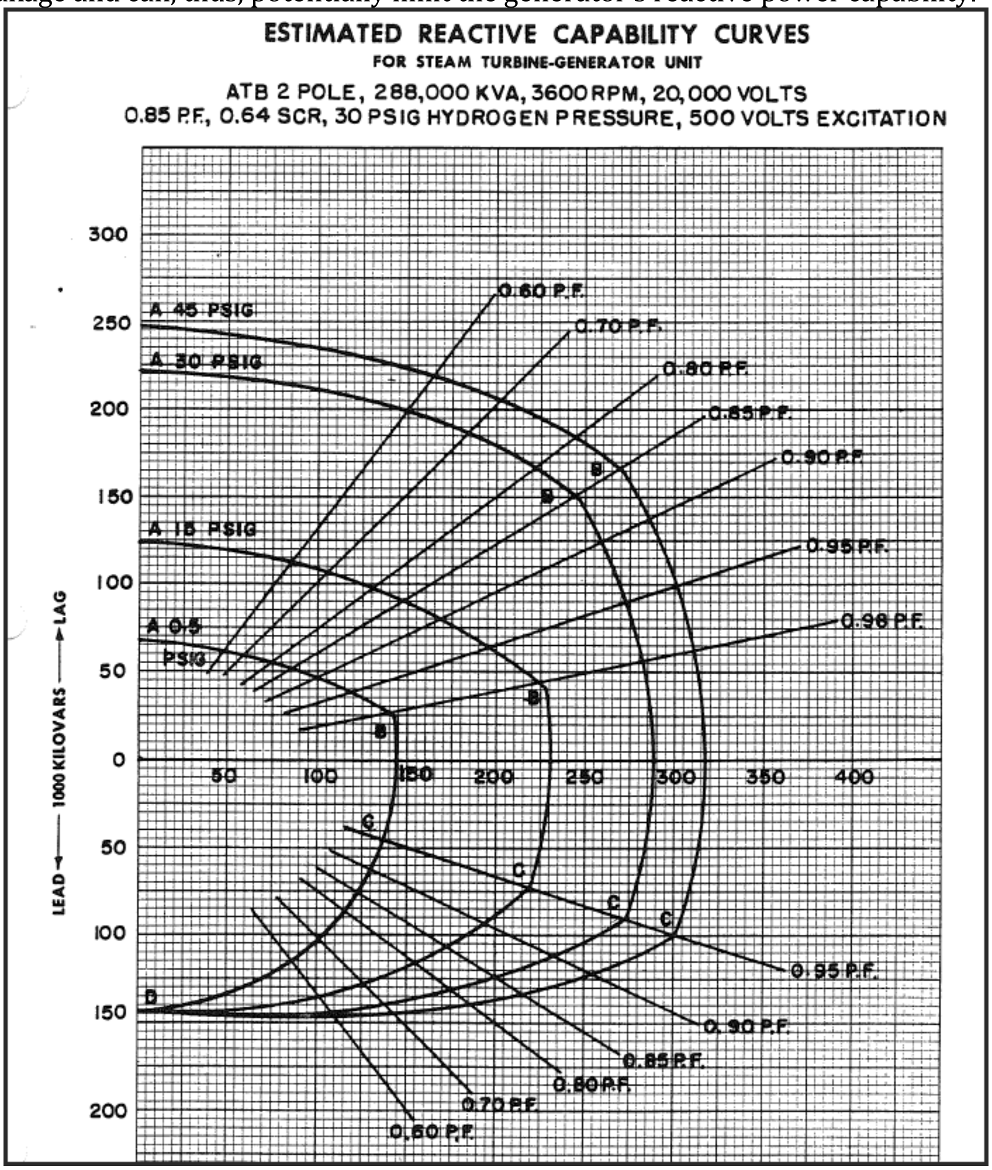


Figure 24

Air Cooled Generators

MVA, MW, and MVAR capability is temperature dependent. Some generators are cooled by ambient air (ex: combustion turbine or CT generators). Some are cooled by air that may be water cooled (ex: hydro generators cooled by air cooled using river water). An example of an air cooled combustion turbine (CT) generator capability curve is shown below (Figure 25).

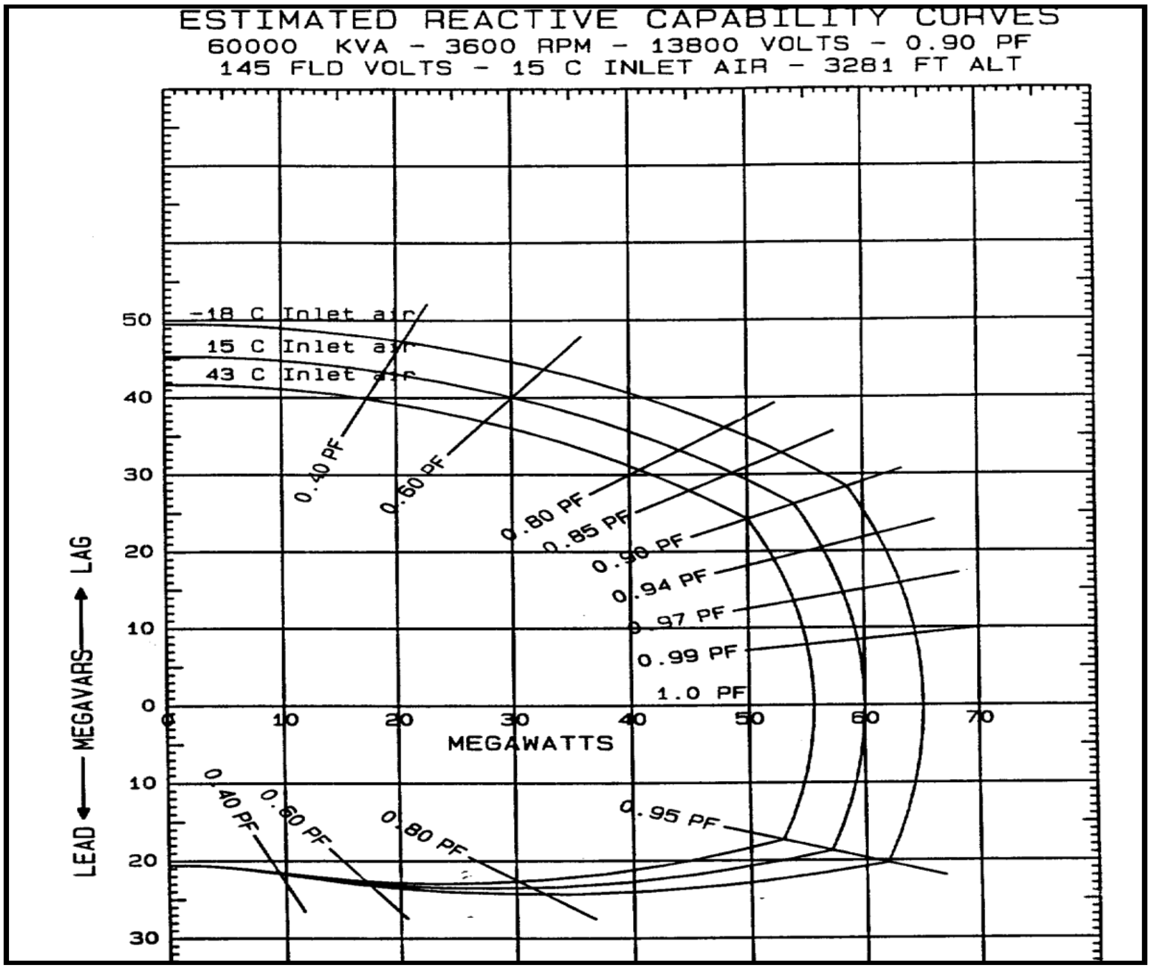


Figure 25

The example CT unit here is name plated as 60 MVA for 15°C (59°F) inlet air. It can only be safely operated at 55 MVA for its summer peak rated temperature of 43°C (109.4°F) inlet air. Therefore, this unit should be modeled using the 43°C reactive power capability curve at its summer maximum and minimum gross capability for summer peak transmission planning studies. If required, these units can be modeled for winter conditions using the capability curve that reflects the expected winter temperatures. The Generator Entity should provide information to support the use of a different curve for summer ambient conditions if the generating unit has equipment, such as chillers, misters or foggers, installed and operating to reduce the inlet air temperatures.

An example of an air cooled hydro generator capability curve is shown below (Figure 26).

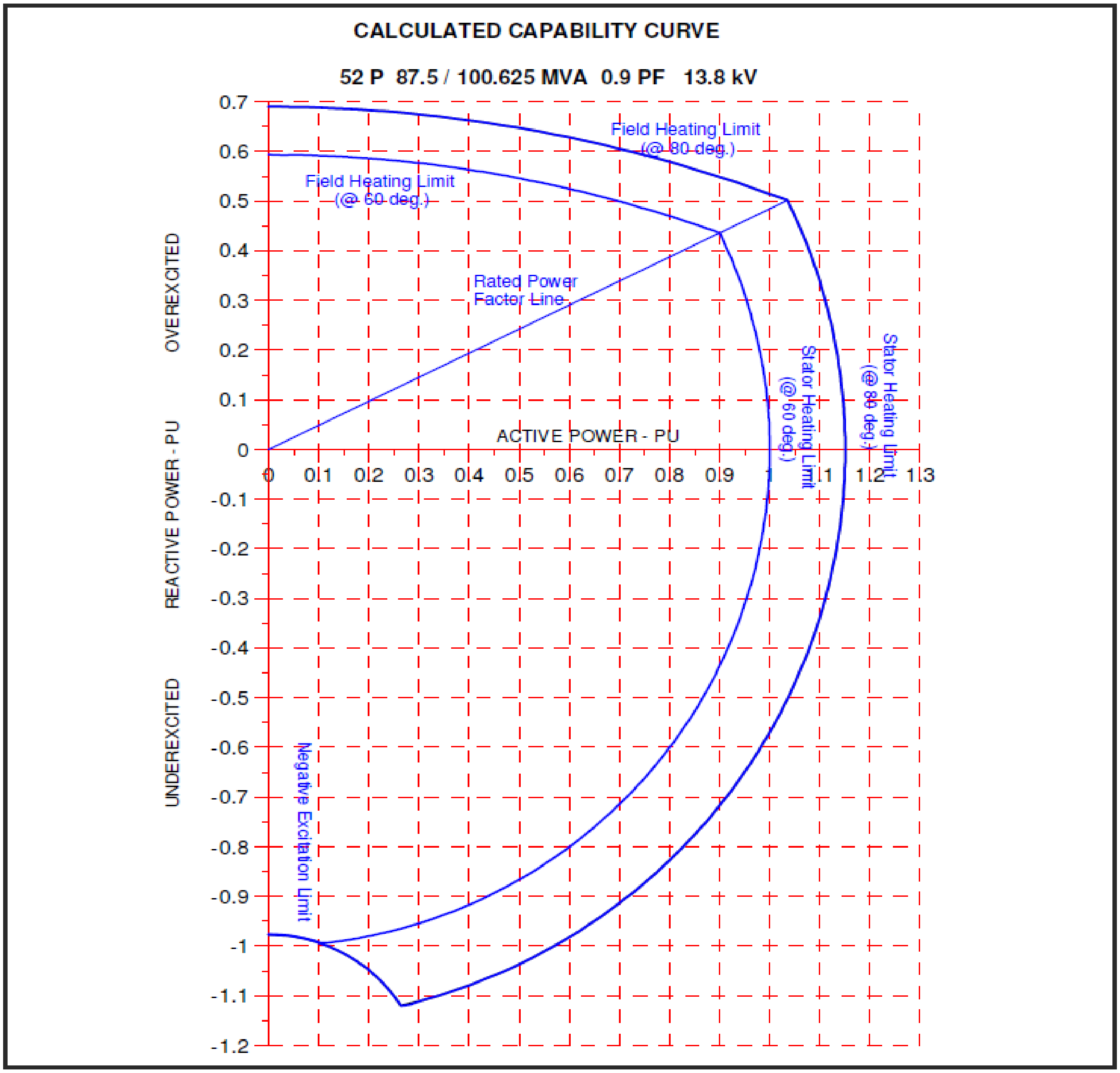


Figure 26

This example hydro generator has two MVA ratings: 87.5 MVA at 60°C rise above ambient (or inlet air) temperature of 40°C (winding temperature of 100°C) and 100.625 MVA at 80°C rise above ambient (or inlet air) temperature of 40°C (winding temperature of 120°C). Some hydro generators have heat exchangers that cool the inlet air. If these inlet air coolers use river water for the coolant, then the river water temperature is a factor in determining the operating temperature limits. It is important that the Generator Entity specify which rating is used for each specific hydro unit. While newer generators or generators with new windings may be capable of operation at the top rating, some older hydro units may be limited to operation at lower ratings due to condition of the stator and/or rotor windings.

Appendix C: GSU Transformer Impacts on Generating Unit Capability

(Reference: IEEE C57.116 Guide for Transformers Directly Connected to Generators)

The generator is typically designed to operate within the D-curve bounds as described in section 4.1 with operating terminal voltage between 95% and 105% of its rated terminal voltage.

When an electrical generator is interconnected to the electrical power system through a generator step-up (GSU) transformer to establish the "generating unit" configuration, the generating unit's reactive power capability is significantly impacted by the GSU transformer's MVA rating, internal impedance, winding voltage ratio (tap setting), and the operating voltage range of the system bus connected at the high voltage side of the GSU transformer. Determination of the optimum GSU transformer parameters, including the tap setting, is a process that requires consideration of several important factors:

The first factor to consider is the GSU transformer's design parameters including its MVA rating, internal impedance, turns ratio (established by the transformer voltage tap setting).

The second factor is the expected transmission system operating voltage range of the system bus at the high voltage side of the GSU transformer connection. The "expected" voltage range includes allowances for expected system contingencies which is a wider range than the variations experienced during normal generating unit and system operation.

The third factor depends on the plant's design or configuration for supplying station service. The generator may be supplying its station service load from the generator terminal bus. Those loads have operating voltage limits which may impose generator terminal voltage limits more restrictive than the 95% to 105% design range of the generator itself. Studies are required to determine the allowable generator terminal voltage range to provide acceptable station service load terminal voltages.

Electrical system studies are typically performed during initial plant planning and design to select and optimize these critical GSU transformer parameters for the specific generating unit being designed (Refer to IEEE C57.116 for details on this process.). These studies are intended to: 1) ensure that a generating unit can maintain the system bus voltage schedule or range for normally expected conditions, 2) the generating unit can provide acceptable reactive (VAR) support during extreme low or high system voltage conditions, and 3) the generating unit's station auxiliary system voltage ranges are optimized for reliable system and unit operation. These studies are typically reviewed and updated, as needed, for changes in transmission system bus voltage schedule, GSU transformer replacements (including spare GSU), addition or replacement of Unit Auxiliary Transformers (UATs), additions or other changes of station service buses and/or loads and for reconfiguration or improvements to the transmission grid at or near the generating unit point of interconnection including generating unit retirements

The following example GSU transformer tap study illustrates these principles. This example is for a large fossil steam turbine generator connected to a 230 kV (nominal) system. For this example, the GSU transformer was being replaced with a new transformer rated at 242kV on the high side and 25 kV on the low side. The following charts (Figures 27, 28 and 29) illustrate the impact of the new GSU transformer high voltage winding tap setting for the 97.5% tap, the 100% (nominal) tap, and 102.5% tap over an expected range of transmission system voltages from 100% (230 kV) to 105% (241.5 kV). (The normal voltage schedule for this unit ranges from 235 kV during valley (off-peak) system load conditions to 238 kV during peak system load conditions.). The diagonal constant system voltage lines on the chart are a function of the GSU transformer impedance. For this example, the generator operating voltage range was determined to be 95.2% to 102.9% of rated generator terminal voltage of 25 kV. This voltage range, represented by the blue vertical lines on the following charts, was determined from an engineering study of the station auxiliary system and takes into account the generator bus-fed unit auxiliary transformer (UAT) and downstream station service transformer (SST) tap settings, impedances, and connected station auxiliary bus loadings. A review of the generator capability curve, excitation limiter settings, and generator operating history indicate the generator is capable of operation between +486 MVARs and -306 MVARs across its entire MW operating range. Observations for each chart are summarized below the corresponding figure.

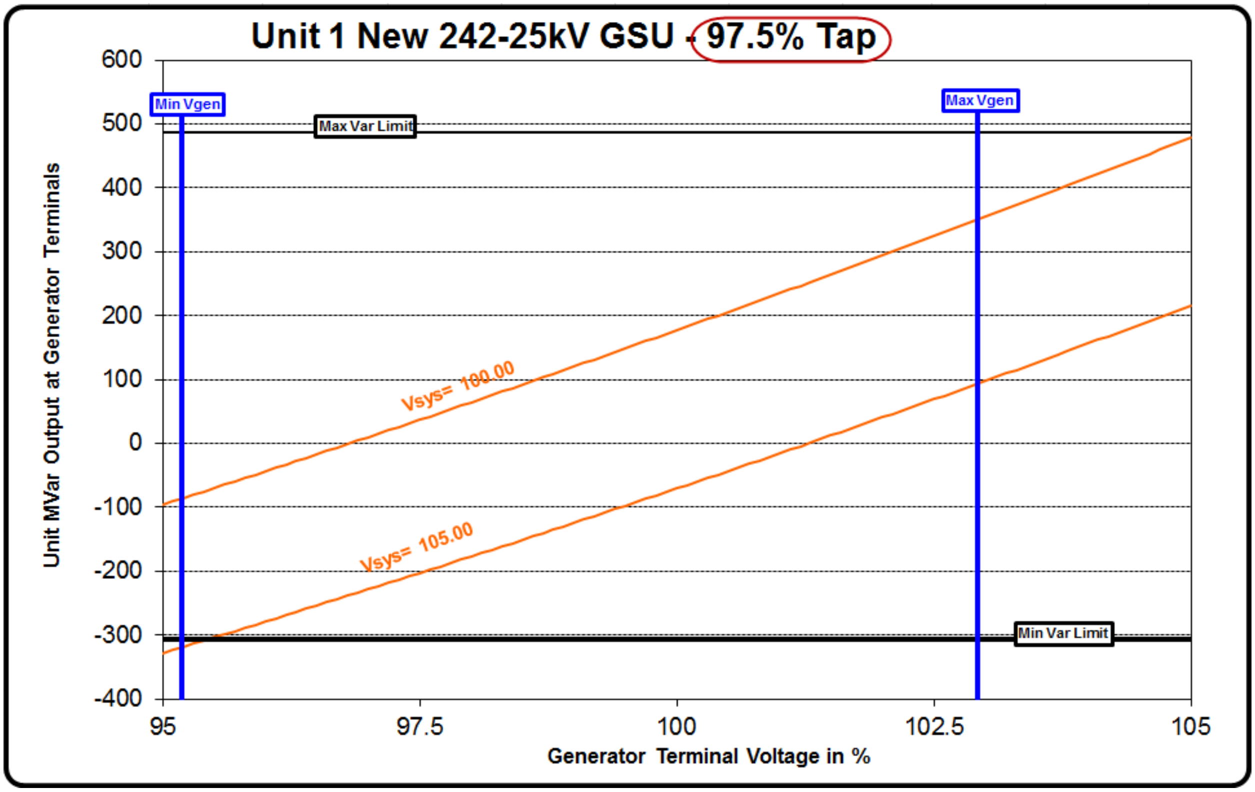


Figure 27

Observations for the 97.5% (236 kV) tap setting:

For system bus voltage at 100% (extreme low), the generator can produce up to 350 MVARs of its maximum of 486 MVARs without exceeding its maximum voltage limit.

For system bus voltage at 105% (extreme high), the generator can absorb up to 306 MVARs of its maximum of 306 MVARs without exceeding its minimum voltage limit.

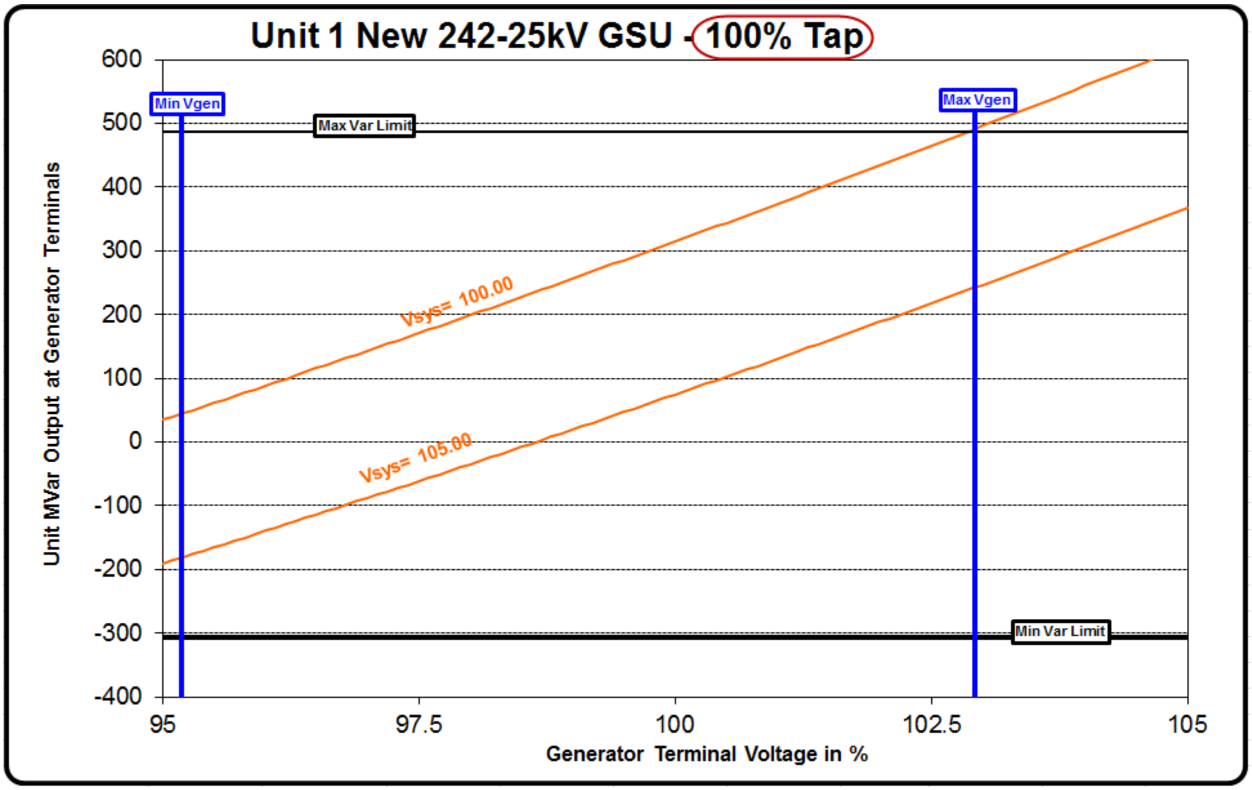


Figure 28

Observations for the 100% (242 kV) tap setting:

For system bus voltage at 100% (extreme low), the generator can produce up to 486 MVARs of its maximum of 486 MVARs without exceeding its maximum voltage limit.

For system bus voltage at 105% (extreme high), the generator can absorb up to 180 MVARs of its maximum of 306 MVARs without exceeding its minimum voltage limit.

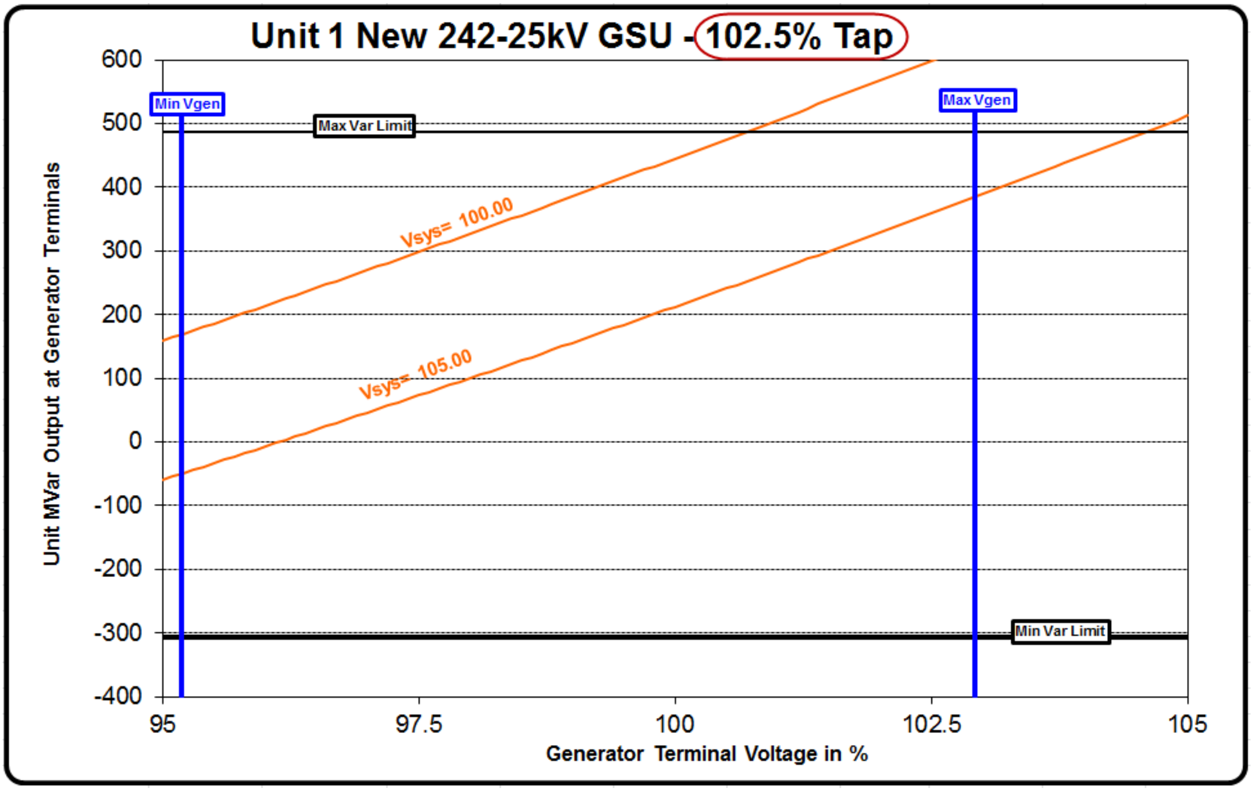


Figure 29

Observations for the 102.5% (254 kV) tap setting:

For system bus voltage at 100% (extreme low), the generator can produce up to 486 MVARs of its maximum of 486 MVARs, but this occurs at a generator voltage of approximately 101% of rated voltage, well below its maximum voltage limit.

For system bus voltage at 105% (extreme high), the generator can absorb only 60 MVARs of its maximum of 306 MVARs at its minimum voltage limit.

The 102.5% tap setting is obviously not the optimum setting for this unit. Either of the previous tap settings appear acceptable, depending upon the specific transmission system needs. In fact, a tap setting between the 97.5% tap and 100% tap could be another good choice.

Appendix D: Potential Reactive Power Operating Limitations

Generating Unit Equipment Limiters and Protective Functions:

Multiple control and protection circuits are installed to protect synchronous generators from overheating and to keep the steady-state operating point within the capability curve defined by the maximum allowable ratings for the machine. Risk of overheating in a synchronous generator results in the need for heat imposed limits on the generator output (MVA). Limiting functions prevent certain quantities from exceeding set limits. If any of the limiters fail, then protective functions should remove appropriate components or the synchronous machine from service. A limit for maximum allowable stator current can be set to protecting the stator winding from overheating. Limits for maximum allowable over-excitation are set to protect the generators field winding and sometimes the excitation system from overheating, while under-excitation limits are included for (small-signal) stability reasons. End region heating limits are set to protect against localized heating in the end region caused by eddy currents during underexcited conditions.

The output capability for synchronous generators are rated in terms maximum MVA, which can be carried continuously without overheating, at a specified voltage and power factor. While the maximum active power output is limited by the capability of the prime mover, multiple factors can as discussed above limit the continuous reactive output capability of a synchronous machine.

There are multiple possible levels that can be used to define the rotor (field) and stator (armature) current limits; one can be defined for the maximum continuous ratings and one for the maximum momentary (short-time) ratings. The short-time ratings allow for a higher degree of over-excitation to be utilized during a short period of time, normally up to a few seconds. Since the modeling of synchronous generators proposed for reporting and verification of their reactive power capability in this document is aimed at steady-state conditions, only the lower, i.e. the continuous, ratings for rotor and stator (if applicable) current limits are to be considered.

Thermal limits are set to restrict the maximum temperature rise and thereby the maximum power loss in different parts of the machine. The stator current limit set by the maximum continuous rating is a fixed value, which results in that the allowable operating area in the capability diagram (P-Q plot) becomes a circle with its center located at the origin and a radius proportional to the terminal voltage. The corresponding displacement of the reactive power output capability due to variations in terminal voltage for the continuous maximum field current limit becomes more complex. In this case, the relation between the field (rotor) current limit and the terminal voltage magnitude also depends on the fact that there will be a change in the degree of saturation in the magnetic circuits, which in its turn will influence the necessary level of field excitation.

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive power capabilities.
- Volts per Hertz (V/Hz) limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer Volts per Hertz capability.
- Time vs. field current or time vs. stator current.

The field OEL (Over Excitation Limiter) provides a control function limiting the field current to a permissible value with regards to thermal overload, in order to protect the filed from damage due to excessive heating. The maximum permissible value is a function of cooling air temperature, hydrogen pressure or other parameters. The action of an Over Excitation Limiter (OEL), which sometimes is referred to as a Maximum Excitation Limiter (MXL), may be immediate or delayed [1].

The field UEL (Under Excitation Limiter) is a function that either overrides the voltage regulator action or adds to terminal voltage set-point, to maintain excitation such that generator output remains above a preset level. Various terms have been applied, often descriptive of the measured variable; minimum excitation limiter, under-excited reactive limit, and rotor angle limiter [1]. The UEL is protecting the stator core end iron from damage due to excessive heating, and prevents operation that could lead to the loss of synchronism. The UEL needs to be coordinated with setting of loss-of-excitation protective relays to avoid tripping of the synchronous generator.

The stator current limiter is designed to protect the generator core and GSU transformer from thermal damage due to excessive magnetic flux resulting from low frequency and/or overvoltage. Sustained excessive magnetic flux can cause overheating and damage to the unit transformer and generator core. The stator current limiter provides a function that can act to prevent the armature (stator) current from exceeding a pre-set value, thereby avoiding thermal overloads, which can be caused by a high reactive power at high active power levels.

The Volts per Hertz (V/Hz) limiter provides a function acting to prevent ratio of terminal voltage to frequency from exceeding a pre-set level. The purpose is to prevent excessive magnetic flux in the synchronous machine and connected transformers [1]. Both synchronous machines and transformers are generally provided with V/Hz protection to avoid excessive magnetic flux density levels. Damage due to excessive magnetic flux seems to occur most frequently when synchronous machines are off-line prior to synchronization.

[1] IEEE Standard 421.1-2007 Standard Definitions for Excitation Systems for Synchronous Machines, IEEE Power Engineering Society, 2007

Reactive Power Limiting Factors:

T-G / Exciter Vibration – Vibration Monitoring & Analysis, Maintenance Inspections

Shorted Turns – Vibration Monitoring & Analysis, Maintenance Inspections, Flux Probe Tests

Gen H_2 Cooling Problems – Plant Monitoring/Indications, Maintenance Inspections, Corrective Maintenance

H_2 Leakage

H_2 Purity

Equipment Cooling Problems - Plant Monitoring /Indications, Preventive & Corrective Maintenance

GSU Cooling Pumps / Fans Out of Service

GSU Coolers Plugged / Dirty

Generator Bus Cooling Problems & Hot Spots

Generator Circuit Breakers

GSU Winding or Oil Temp Alarm Settings – Review of Set-points & Alarm Procedures, Periodic Testing of Temperature Devices.

Generator & Exciter Limiter/Protection Mis-coordinations / Mis-calibrations – Review of Settings, Offline Testing Calibrations - PRC-019

Potential Errors Due To Plant Instrumentation – Identify & Correct Problems via Ongoing Monitoring, Calibration Checks

Voltage Instrumentation: Switchyard, Generator, SS Buses

VAR Instrumentation: Generator, SS Load Points

Current (Ampere) Instrumentation: SS Bus Load Points

Generator Field Voltage, Field Current

Appendix E: Transmission Study Horizons

1 Reactive Power Modeling for System Studies

To consider generator reactive power capability in steady state evaluations of the bulk electric system, power flows and state estimators are used to simulate system behavior for a given snapshot in time. Transmission planners and operators generally perform three basic types of studies:

Real-time operation studies

Operational planning (next hour to 12 months) studies

Long-term planning (12 months to 15 years) studies

Real-time operation requires a continuous review of ever-changing system conditions. Operational and Long-term planning studies focus on developing conservative snapshots of the system, which represent projected conditions, primarily during winter, summer and shoulder peak conditions.

There should be some consistency across the three types of models used in the studies mentioned above. However, it should be recognized that the parameters and data input for planning models can deviate from operations and real-time models due to the bulk electric system condition changes and due to the need to study the system in an intentionally conservative manner to predict when changes may be needed.

2 Real-Time Planning Studies

Real-time evaluations are performed continuously by Transmission Operators. Most transmission operators have tools which perform state estimation based on real-time field measurement data to form a base condition and then simulate a wide variety of contingencies. System voltages, interchange and generation patterns vary significantly over time due to changes in loads, maintenance, etc. Real-time also presents some different circumstances than analyzed in planning studies such as system loads exceeding the peak forecast loads with both forced outages and planned maintenance conditions causing actual system dispatch to be different than the planned cases. Although some of the assumptions from planning can be applied (e.g., movement of switched shunts, LTCs, PARs), real-time models must also be capable of representing generators under the wide range of system conditions, including voltage variations, that can occur.

3 Operational Planning Studies

Operational planning (includes near-term and seasonal) studies usually simulate conditions expected during the upcoming summer, winter and shoulder peak load conditions. Known generator and transmission system outages (forced and planned) are also simulated. Those performing the studies also make adjustments in their models for any forecasted delays in major projects. Generally, assumptions such as base load units operating at their normal continuous maximum capability for the season under study, and other assumptions used in long term planning studies, apply in this arena, thus yielding similar generation patterns. However, known planned maintenance, and in some cases, expected forced outages of generation based on historical trends may be reflected in the base conditions studied. The studies include evaluation of contingency loss of generation or transmission facilities.

4 Long-term Planning Studies

Long-term planning studies have a long term perspective. These studies typically simulate projected peak system load conditions expected to occur in future years as a base condition. The studies determine when and where transmission system reinforcements will be required. These types of studies have historically emphasized analysis of potential thermal limitations since siting large generating plants and/or building transmission and substations takes a lot longer than installing the capacitors, SVCs, etc., required to bolster voltages.

Generators are dispatched to meet the demand adjusted for projected interchange. Contingencies representing loss of Transmission and/or Generation facilities are then simulated. The study results usually represent post-contingency expected system conditions after adjusting for switchable shunts, LTCs and PARs where applicable. Alternative expansion plans to remedy any problems which are identified are then evaluated by the planners to achieve the most cost efficient and effective solution. Planned projects are assumed to be installed per the stated in-service dates. Unless long term maintenance schedules dictate otherwise (usually for nuclear plants), most base load generation is assumed to be available and is dispatched to maximum continuous capability for summer and winter peak load base cases. Combustion turbines (CTs) that are 'on-line' are typically assumed to be on at their continuous full capability. The type of reactive model used is independent of the fuel-type for both Steam and Combustion Turbine units.

Transmission planners often vary generation and interchange levels to simulate a variety of peak load conditions. In some cases users simulate the dispatch changes by modeling discrete unit outages but in some cases, it is expedient to vary the generation by interpolation/extrapolation. Long term planners may also study other extreme conditions such as seasonal peak loads, shoulder loads and/or light (minimum) load conditions.

Appendix F: Representation of Generators in Power Flow Models

Reactive Power Limits must be consistent with unit configuration in the Power Flow model

The appropriate values for the generator output and the auxiliary load depend on the configuration simulated in the power flow model. The Transmission Planner must have knowledge of the plant arrangement (one-line) and the transformer characteristics to appropriately adjust the generator parameters (Pgen, Qgen, Pmax, Pmin, Qmax and Qmin) to be consistent with the unit configuration simulated in the power flow model.

Four configurations commonly used in power flow models are illustrated in the figure below (Figure 30). The net power delivered to the transmission system is 100.41 MW and 76.98 MVAR in each configuration.

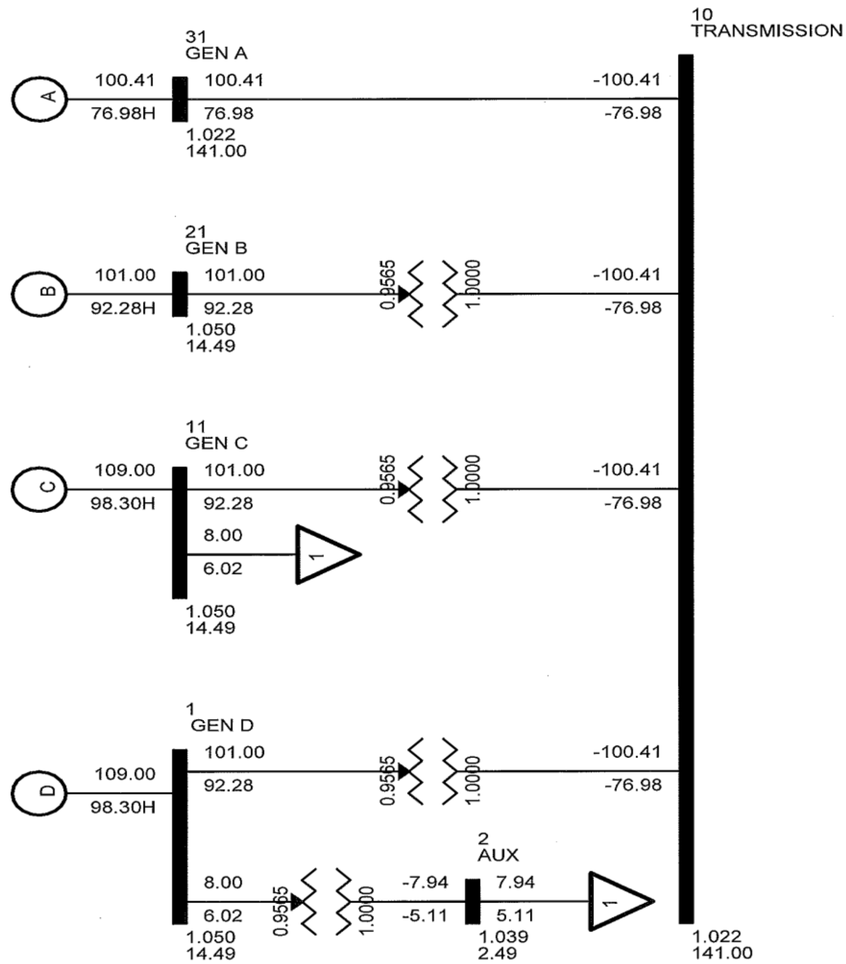


Figure 30

GEN A – This configuration has the generator connected directly to the transmission system and does not model the GSU transformer, aux load or unit aux transformer. The generator output (100.41 MW and 76.98 MVAR); therefore, equals the flow into the transmission system.

GEN B - This configuration includes the GSU transformer but not the aux load or unit aux transformer. The generator output must be modeled at 101.00 MW and 92.28 MVAR because of the GSU transformer losses.

GEN C - This configuration includes the GSU transformer and aux load but not the unit aux transformer. The generator output must be modeled at 109.00 MW and 98.30 MVAR to supply the aux load and the GSU losses.

GEN D - This configuration includes the GSU transformer, aux load and unit aux transformer. The generator output is unchanged from GEN C but the aux load must be reduced to account for unit aux transformer losses.

The recommended models should represent GSU transformers and include generator aux or station service load.

Simulation of option GEN C or GEN D in the power flow model is recommended because P and Q are the generator gross values. The gross values are: 1) directly comparable to the generator D-curve, 2) consistent with the values measured at the generator terminals, and 3) appropriate for transient stability simulations. Option GEN C, however, does not provide the capability to monitor the aux bus voltages in the power flow simulations. For option GEN C, the Transmission Planner may be required to adjust the generator terminal limits to less than the standard +/-5% to ensure that the voltages at the aux buses are maintained within the applicable limits. The Transmission Planner should work with the Generator Entity to obtain the generator voltage limits and auxiliary bus loadings and voltage limits.

Appendix G: Reporting of Test Results

Test results including limiting factors must be summarized and reported in accordance with MOD-025-2 Attachment 2 and any applicable Regional criteria. This will typically include a simplified one-line diagram, a table, and possibly a markup of the generator reactive power capability curve showing design limits versus the limits determined via testing.

If transmission bus voltage, generator terminal voltage, or station service bus voltage limits the unit MVARs during a test to a value less than the expected MVAR capability determined prior to the testing, then additional effort may be required to determine the MVAR capability needed for the transmission system models. The Transmission Provider should coordinate additional studies and/or testing with the Transmission Planner, Transmission Operator, and Generator Entity as appropriate.

A survey on experience with staged testing in the SERC region indicates that a validation approach based solely on test results may result in under reporting the available capability, as the major limiting factor observed in testing (~60%) have been due to voltage (See SERC Reactive Power Capability Test Survey - Summary of Results below.). Thus, the NATF believes a validation program that permits all tools including Engineering Analyses, Staged Testing and reviews of Operating Data is needed to better clarify how a units reactive power capability should be modeled. The validation program should ensure that the actual system models are exercised as part of the validation effort since expertise with grid model software historically is not maintained by the Generator Entity.

SERC Reactive Power Capability Test Survey - Summary of Results

A survey of major utilities within the SERC Region performed lagging reactive power capability testing on 85 generators of 8 major utilities/generator entities. During the tests:

- 22% of generators achieved ≤50% of their D-curve capability
- 36% of generators achieved ≤60% of their D-curve capability
- 54% of generators achieved ≤70% of their D-curve capability
- 68% of generators achieved ≤80% of their D-curve capability
- 88% of generators achieved ≤90% of their D-curve capability
- Minimum was 15% of D-Curve capability

The average was 67% of the D-curve capability. The limiting factors were:

- 61% limited by voltage (generator, auxiliary system and/or transmission)
- 11% limited by Field current limit or limiter
- 11% limited by D-curve capability
- 7% limited by GSU transformer
- 7% limited by stator current or temperature
- 5% limited by GSU
- 4% limited by AVR range limit
- 1% limited by shorted rotor turns

- 1% limited by AVR forcing alarms
- 1% limited by vibration

Leading reactive power capability testing was performed on 32 of these generators. During the tests:

- 59% of generators achieved ≤ 50% of their under excitation limiter (UEL) Setpoint
- 72% of generators achieved < 60% of their UEL Setpoint
- 78% of generators achieved < 70% of their UEL Setpoint
- 81% of generators achieved < 80% of their UEL Setpoint
- 91% of generators achieved < 90% of their UEL Setpoint

The limiting factors were:

- 66% limited by voltage
- 19% limited by UEL (unexpected)
- 9% limited by UEL (as expected)
- 2% limited by stator current or temperature
- 2% limited by AVR range limit
- 2% limited by end winding vibration concerns

Appendix H: Glossary of Terms

D-Curve - Generator Capability Curve

GSU – Generator Step-up Transformer

MEL – Minimum Excitation Limiter

MXL – Maximum Excitation Limiter

OEL – Over Excitation Limiter

SS – Station Service

SST – Station Service Transformer

UAT – Unit Auxiliary Transformer

UEL – Under Excitation Limiter

URAL – Under Reactive Ampere Limiter

V/Hz – Volts per Hertz