System stability analysis

Introduction

ATC also designs its system to meet stability criteria that are more stringent than NERC Standards. In the Planning Criteria section of this report, the Transient and dynamic stability performance assessment discussion gives details about the ATC's criteria for assessing system stability.

Reviewing compliance with NERC Standards and ATC stability criteria is a continuous process. Each year ATC adds to its library of studies. There are two components to consider in assessing system stability. One component is the angular stability of the system or often more generally referred to as generator stability. The second component is the system's voltage stability. Our approach to assessing both of the system stability components is described below.

Generator Stability

For each 10-Year Assessment, generator stability is assessed at all major generator stations connected to the ATC system. Numerous generator interconnection studies add to our knowledge of the ATC system stability response to Category B2, C3 and selected C8 outages. A MRO/RFC joint on-site review completed in December 2008 determined that ATC was fully complaint with NERC Standards that cover multiple outages (Category C), including the system's stability response to multiple outages.

In the 2009 10-Year Assessment, we have revisited a select list of generator stations as described below. As generator stability concerns arise they are evaluated and appropriate corrective actions are developed and implemented. Generator stations with total net output above 100 megawatts and associated transmission lines operating usually above 100 kV are generally selected to assess system angular stabilities.

The methodology used in assessing the major generator stations includes a review to determine that no significant system topological changes have occurred near the generator stations other than local load growth. The methodology also includes a review of the parameter values and the model types used to represent the dynamic response of the units at the generator stations in system angular stability simulations to determine that no significant changes have occurred. In addition, this methodology includes a review of the date of the last stability study conducted for each of the major generator stations to determine that the elapsed time does not exceed 5-years. Considering the number of existing major generator stations shown in Table ZS-7 - ATC System Angular Stability Assessment this requires that at least six major generator stations be included in the system angular stability analysis for each 10-Year Assessment in order to complete a study of all major generator stations in a five-year sequence.

If these criteria are confirmed, the generator stability results of existing studies are still applicable and are acceptable in the following years with proposed system upgrades. If any of these criteria are not met then generator stability is reviewed and/or restudied.

In this Assessment, power flow models were compared with the 2008 power flow models. In addition, the parameter values and types of dynamic models (e.g. generator, exciter, power system stabilizer, governor etc.) currently used to represent the major generator stations in dynamic simulations were compared with those in the 2008 10-Year Assessment studies. The review identified six (6) generator stations that had either:

a) Significant system topological change near the station,
b) A significant change in the parameter values or type of dynamic model used to represent the unit responses during simulation,
c) Were at or approaching the five-year elapsed time criteria or
d) A combination of these criteria.

The six (6) generator stations identified are: Valley, Port Washington Combined Cycle Block 1 (CC1) and Combined Cycle Block 2 (CC2), Kewaunee, West Marinette, Cypress and West Campus. These stations are shown high-lighted in Table ZS-7 - ATC System Angular Stability Assessment.

The Valley, Port Washington and Kewaunee plant selection involved changes in a dynamic model or parameter changes within a dynamic model. With the Valley plant the existing exciter models were replaced on each of the units with the new exciter model and data provided by the generator owner. Port Washington combustion turbine units had the governor models replaced as part of the RFC model standardization project, as well as, parameter changes for the generator models representing the Block 1 units that were provided by the generator owner. Kewaunee involved a change in the governor model from a standard model to a user-developed model provided by the generator owner.

The West Marinette and West Campus plant selection involved significant system topological changes near the plants, while Cypress involved both dynamic model changes as well as topological changes. West Marinette significant system changes included addition of the Menominee 138/69-kV transformer as well as re-configuration of the 69-kV system between Pioneer, Pound, Sandstone, Crivitz, High Falls and Thunder substations; plus addition of the Wells Street-Ogden 69-kV line. West Campus significant system changes included the conversion of the two Blount-Ruskin 69-kV lines to a single 138-kV line, plus re-configuration of the 69-kV lines involving Mendota Substation. In addition, the installation of the North Madison-Huiskamp 138-kV line and loop-in of North Madison-Yahara River 138-kV line into the new Vienna Substation.

Cypress involved generator model parameter changes due to a change in the generator manufacturer and the number of machines from 41 to 44, plus a significant a change in models used in the control of the supplemental reactive compensation. In addition, the system near the plant also had significant topological system changes. These included the addition of the Werner West-Highway 22, Highway 22-Gardner Park, and Highway 22-Morgan 345-kV lines, plus a second Kewaunee transformer and connection of two wind farms totaling 198 megawatts to the 138-kV system in the area.

All these major generator stations were re-studied as part of the system angular stability analysis of the 2009 10-Year Assessment with the ATC stability criteria applied. All the assessed generators met the ATC stability criteria with the exception of the Valley plant and the West Marinette plant for a three-phase fault with delayed clearing. As shown in Table ZS-7 - ATC System Angular Stability Assessment, all assessed generators in the ATC area met the applicable NERC Category B2, C3, and C8 criteria.

In the case of Valley, stability simulations meet NERC requirements for phase-ground fault with delayed clearing (C8), but do not meet ATC requirements for a three-phase fault with delayed clearing. One possible mitigation being developed to reduce clearing times from existing 14.1 cycles to 11.5-11.7 cycles to meet ATC stability criteria for the Valley plant includes replacement of the breaker failure relays on lines 301, 302 and 311 plus replacement of the existing three-cycle oil breakers with two-cycle gas breakers at positions 314, 321, and 324. Existing phase-ground fault duty at the Valley plant would have to nearly increase by 35 percent under present clearing times before the NERC requirements would be exceeded. This provides an adequate margin in order to plan and implement system improvements needed to meet ATC stability criteria.

In the case of West Marinette, stability simulations meet NERC requirements for phase-ground fault with delayed clearing (C8), but do not meet ATC requirements for a three-phase fault with delayed clearing. Possible mitigation being developed to reduce the existing 14-18 cycle clearing time to that of 7.75-11.5 cycle clearing time in order to meet ATC stability criteria would involve replacement of circuit breakers and breaker relaying as well as possibly a re-configuration of the substation and are planned to be taken into consideration as other system improvements are needed in the area. Existing phase-ground fault duty at the West Marinette plant would have to nearly double under present clearing times before the NERC requirements would be exceeded. This provides an adequate margin in order to plan and implement system improvements needed to meet ATC stability criteria.

Voltage Stability
ATC is still developing a rigorous process for assessing voltage stability across the system. Currently we monitor voltages for single and multiple contingency events throughout the ATC system to screen for indications of where voltage stability may be an issue.

A detailed voltage stability analysis was last performed in the Rhinelander area of Zone 1 in 2003 that covered the period from 2003 to 2005. As a result of this study, solutions were developed and implemented in the Rhinelander area to address the voltage stability concerns that were found. These solutions included the following:

- Installation of two new, high speed 115 kV breakers (2 cycle) at Aurora Street on A-313 and Highway 8 on D-56 with maximum primary clearing time of 3.75 cycles in 2003.
- Installation of a 16.9 MVAR, 115-kV capacitor bank at Summit Lake Substation in 2003.
- Relocation of the Reedsburg 6.0 MVA D-SMES unit to the Clear Lake Substation in 2004.
- Conversion of the Pine to Eastom 46-kV line to 115 kV in 2004.
- Installation of a new 115-kV line from Skanawan to Highway 8 in 2005.

In the 2008 10-Year Assessment, it was decided that a new detailed voltage stability analysis be performed in the Rhinelander area of Zone 1 to cover the period from 2008 to 2013 to assess the impact of these improvements along with the addition of a new Cranberry-Lakota Road (Conover) 115-kV line in 2008 and the rebuild/conversion of the Lakota Road (Conover)-Plains 69 kV path to 138 kV in 2010. The Lakota Road Substation includes a 138/115 kV transformer to interconnect the 115 kV and 138-kV lines together and includes a 138/69 kV transformer to connect to the Conover 69 kV system. The Lakota Road (Conover) -Twin Lakes - Iron Grove segment of the Lakota Road (Conover)-Plains 138-kV line is scheduled for completion in 2009 and the Iron Grove-Aspen-Plains

138 kV segment is scheduled for completion in 2010. In addition, the study also includes evaluation of the continued need for the D-SMES units and Undervoltage Load Shedding (UVLS) relaying in the Rhinelander area.

As indicated in the 2008 Assessment, the results on this study were to be reported in either an update of this Assessment or in a future Assessment. The work on this study was continued for the 2009 10-Year Assessment, but due to a recent change in the load breakdown used for the Rhinelander area as well as an expansion in the study scope the study has not been completed and will, in fact, need to re-done. It is expected that the work on this study will be reported in a future Assessment.

The MRO/RFC joint on-site review completed in December 2008 determined that ATC was fully compliant with the voltage stability assessment requirements in the applicable NERC standards.

Conclusion
Based on these assessments and numerous other studies, the ATC network will meet NERC System Stability Standards assuming reinforcements contemplated in this 10-Year Assessment, operating procedures, and special protection systems are implemented.