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 ATC's criteria for assessing system stability.

Reviewing compliance with NERC Standards and ATC stability criteria is a continuous process with ATC adding to its library of studies each year. There are three components to consider in assessing system stability; Angular stability of the system (often referred to as generator stability), Voltage stability and Small signal stability. Our approach to assessing all of the system stability components is described below.

Generator Stability

For each 10-Year Assessment, generator stability is assessed at selected major generator stations connected to the ATC system based on generator, exciter, power system stabilizer and governor equipment changes plus any associated system topology changes. Numerous generator interconnection studies add to our knowledge of the ATC system stability response to select NERC Category B, C, and D contingencies.

In the 2011 10-Year Assessment, we have reviewed 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 MW and associated transmission lines operating usually above 100 kV are selected to assess system angular stability.

The methodology used in assessing the major generator stations includes:

1. A review to determine that no significant system topological changes have occurred near the generator stations other than local load growth.
2. A review of the parameter values and the model types used in representing the dynamic response of units at the generator stations in system angular stability simulations to determine that no significant changes have occurred.
3. 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 6 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 5-year rotation.

If any portion of these criteria is confirmed, the generator stability results of existing studies are reviewed and a determination is made if past studies are still applicable. If any of these criteria are not met then generator stability is reviewed and/or restudied.

In the 2011 10-Year Assessment the power flow models were compared to the 2010 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 2010 TYA studies. For the 2011 10-Year Assessment, the review identified six (6) generator stations that did not meet the aforementioned criteria and required an evaluation of the generator's stability performance.

The six (6) generator stations identified are: Neevin, Pulliam, Weston, Columbia, Christiana and Sheboygan Energy Center. These stations are shown high-lighted in Table ZS-7 - ATC System Angular Stability Assessment.

The Neevin, Pulliam, Weston, Columbia, Christiana and Sheboygan Energy Center plant selection was based primarily on the fact that they were approaching the 5-year time criteria. Sheboygan Energy Center is the only facility in the list that has had recent study work done in the local area which is used to determine what additional supporting analysis is needed to ensure full compliance with reliability standards. Minor changes in governor dynamics data was identified for Pulliam, Columbia and Weston that has no impact on performance. No major topology changes were identified for the ATC system that will impact the evaluation of the BES generation.

These six major generator stations were evaluated as part of the system angular stability analysis with the ATC stability criteria applied. Table 1 provides a summary of the NERC category contingency types assessed for this generator stability analysis.

In summary, Neevin, Pulliam, Weston, Sheboygan Energy Center, Christiana and Columbia generating facilities were able to meet all of applicable NERC TPL-001 through TPL-003 reliability standards for the Bulk Electric System (BES) and the ATC Planning Criteria for the ATC Transmission System.

Stability issues associated with NERC category D4 contingencies were identified for Neevin, Pulliam and Christiana facilities and issues associated with NERC Category D2, and/or D3 were identified for Christiana and Columbia facilities. These issues are summarized in the following paragraphs with inclusion of potential mitigation options discussed for those instances where the ATC stability criteria were not met.

Table 1: Summary NERC Category Contingency Assessment for Angular Stability Analysis

NERC Contingency Category	Generator Stations Studied [i, ii]					
	Neevin	Pulliam	Weston	Sheboygan Energy Center	Christiana	Columbia
A	(1), a	(1), a	(1), a	(1), a	(1), a	(1), a
B1	b	b	b	b,g	b	b
B2	(2)	(2)	c	g	(2)	(3)
B3	d	d	c	g	(1)	(1)
B4	e	e	e	e	e	e
C1	c	c	c	g	c	c
C2	c	(3)	c	g	c	c
C3	(2)	c	(4)	g	(4)	(4)
C4	e	e	e	e	e	e
C5	(1)	(2)	(4)	g	(1)	(2)
C6	b	b	b	b,g	b	b
C7	d	d	(2)	g	(1)	(2)
C8	(6)	(15)	(9)	g	(8)	(5)
C9	(2)	(4)	(2)	(1)	c	(2)
D1	b	b	b	b,g	b	b
D2	(4)	(11)	(9)	g	(9)	(5)
D3	d	d	(2)	g	(3)	(2)
D4	(2)	(3)	c	g	(2)	c
D5	c	c	c	g	c	c
D6	f	f	f	f	f	f
D7	f	f	f	f	f	f
D8	f	f	f	f	f	f
D9	f	f	f	f	f	f
D10	f	f	f	f	f	f
D11	f	f	f	f	f	f
D12	f	f	f	f	f	f
D13	f	f	f	f	f	f
D14	f	f	f	f	f	f

Notes:

i. Number enclosed within parenthesis indicates number of contingencies studied for each NERC category.

ii. Lower case letters provide the following explanations/comments regarding consideration of applicability of the NERC category contingency:

a. Intact system 20 second simulation.
b. Loss of generation will result in a more stable system and is less severe than other contingencies considered.
c. Contingency not as severe as other contingency types in category.
d. No contingencies were evaluated because no bulk electric system transformers are located in the study area.
e. Not applicable since there are no DC lines in ATC system under study.
f. Not applicable for generator stations under study.

Both the Neevin facility and the Pulliam facility met all applicable NERC and ATC performance requirements. For each generating facility, a single NERC TPL-004 contingency caused these units to lose synchronism with the transmission system. However, this contingency type is beyond ATC's performance criteria and TPL-004 does not require a system improvement for this condition.

Christiana facility met all applicable NERC performance requirements and did not meet ATC's performance requirements for twelve (12) TPL-004 contingencies. TPL-004 does not require a system improvement for these conditions but ATC's Planning Criteria will require system improvements. ATC's Planning Criteria recognizes that portions of ATC's footprint were not originally designed to meet the more stringent criteria adopted at ATC's formation. For these particular contingencies, new relay settings will be issued, which will result in the Christiana facility meeting ATC's performance requirements. For this generating facility, two (2) other NERC TPL-004 contingencies caused these units to lose synchronism with the transmission system. However, these contingency types are beyond ATC's performance criteria and TPL-004 does not require a system improvement for this condition.

Columbia facility met all applicable NERC performance requirements and did not ATC's performance requirements for two (2) TPL-004 contingencies. TPL-004 does not require a system improvement for these conditions but ATC's Planning Criteria will require system improvements. ATC's Planning Criteria recognizes that portions of ATC's footprint were not originally designed to meet the more stringent criteria adopted at ATC's formation. For these particular contingencies, new relay settings will be issued, which will result in the Columbia facility meeting ATC's performance requirements.

Both the Sheboygan Energy Center facility and the Weston facility met all applicable NERC and ATC performance requirements.

As shown in Table ZS-7 - ATC System Angular Stability Assessment, all assessed generators in the ATC area meet the applicable NERC TPL-001 through TPL-003 criteria and will meet ATC's Planning Criteria through proposed improvements that will be implemented by ATC.

Voltage Stability

ATC uses steady-state analysis to assess voltage stability throughout the ATC system. Low voltages or non-convergent simulations during single and multiple contingency events under both near and longer term horizons indicate where there may be voltage stability concerns. Additionally, each angular stability study performed by ATC screens the system for voltage stability issues through the application of the ATC voltage recovery criteria described in ATC's Planning Criteria. If steady state or dynamic analyses identifies areas of weakness indicative of voltage instability, further examination of system characteristics and, possibly, more detailed analysis will be performed. This more detailed analysis may include replacement of lumped load modeling with more specific modeling of the distribution system and its loads.

The Rhinelander area of Zone 1 (the 115-kV network between the southern substations of Pine and Aurora Street and the northern substation of Cranberry) was studied in 2010 and 2011 through a detailed dynamic analysis to evaluate the continued need for the superconducting D-SMES units in the area after recent system improvements. These improvements included adding a Cranberry-Lakota Road 115 kV line, rebuilding the Lakota Road-Plains 69 kV path to 138 kV, and adding 138/115 kV and 138/69 kV transformers at Lakota Road. After examining voltage stability for more than 150 events under NERC Categories A, B, C and D for system peak load conditions it was determined that system performance requirements were met with only the dynamic reactive power capability of the D-SMES in operation. This allowed ATC to de-energize the superconducting magnetic energy storage component of the D-SMES units and reconfigure them as D-VAR units which only provide reactive compensation for voltage support.

ATC is performing additional dynamic simulations in 2011 to determine if D-VAR units can be eliminated in conjunction with ATC's planned implementation of under voltage load shedding relays (UVLS), replicating existing distribution level, customer owned under voltage relaying. The UVLS program under evaluation would be installed at a single location in the western part of the Rhinelander area. This location currently serves a single end-use customer who is already using their own under-voltage load shedding relaying to separate their facilities from the network to preserve their internal load and generation. From a transmission standpoint, this action looks like the loss of approximately 24 MW of load although the actual amount will vary based on the electrical output of internal plant generation. The installation of the ATC-owned under-voltage shedding relay would replicate the end-use customer's relay settings and improve system performance for specific maintenance outage conditions combined with certain severe (i.e. TPL-003) contingencies.

Small Signal Stability

In the 2011 10-Year Assessment, ATC performed a small signal stability assessment for ATC transmission system in accordance with the now-retired Midwest Reliability Organization (MRO) standard PRC-502-MRO-01. The main objective of the small signal stability assessment is to ensure that power system stabilizers on generating units are designed, installed and tuned as required to dampen power system oscillations that might occur on the electrical system.

ATC's small signal stability assessment examined local, inter-plant and inter-area modes to ensure that no poorly damped oscillations are observed. The local and inter-plant modes of oscillation are studied as part of ATC's annual 10-Year Assessment and for each generator interconnection study for a proposed generating facility. The resulting performance of the interconnected generation is compared to the rotor angle damping criteria defined in ATC's Planning Criteria, which ensures acceptable system performance.

For the 2011 10-Year Assessment of inter-area modes of oscillations, system simulations were performed for 2011 and 2015 system conditions including light load, shoulder load and peak load levels. Because the ATC system is significantly impacted by the transfer of power from Minnesota to Wisconsin, the analysis included simulation of heavy power flows from the west. In total, 262 NERC TPL-001, 002 and 003 contingencies categories were evaluated for each system scenario.

ATC's small signal stability assessment demonstrated that all local, inter-plant and inter-area modes of oscillation involving generation located within the ATC footprint met PRC-502-MRO-01 and ATC Planning Criteria requirements.

Conclusion

Based on these assessments and numerous other studies, the ATC network meets NERC System Stability Standards.

Fault Duty Evaluation

Every new generator interconnection that either involves the addition of a generator that provides a fault current contribution to the system, or results in system topology changes, is evaluated within the System Impact phase of the interconnection process. This evaluation determines if the addition of the new generator and related facilities will negatively impact the fault current interrupting capabilities of the existing system breakers. If the fault current is at or near the breaker's capability as the result of the new generator interconnection, projects are identified within the System Impact Study to replace these breakers prior to interconnecting the new generator to the transmission system.

Additionally, every year, ATC evaluates the fault duty capabilities at substations in the existing system topology to determine if breakers located at these facilities are at or near the fault current capability. The results of this fault analysis are compared against a database of equipment ratings to help categorize which breakers at ATC facilities will be replaced. For breakers identified as exceeding their fault current capability, projects are initiated in the near term to replace these breakers. Breakers that are within 3% of their fault duty rating are continuously monitored to determine if changes to the ATC system will require replacement in the near term.

For this analysis, a worst case current interruption exposure for each circuit breaker is evaluated with all generation assumed to be on line and the sub transient reactance or equivalent modeled for all generators. Three-phase and phase-to-ground faults are evaluated with zero fault impedance and all network buses and branches in their normal configuration. Fault currents are calculated in accordance with IEEE/ANSI Standard C37.010-1999 using the X/R multiplying factors for each of the facilities. Currents through a breaker are calculated assuming the worst case fault current through a breaker with a disconnect switch on one side of the breaker open and the fault located between the breaker and disconnect switch. For each circuit breaker, the interrupting capability of the circuit breaker must be greater than the worst case fault current interrupting exposure of the circuit breaker. ATC considers a circuit breaker over duty when it reaches a negative margin. Circuit breakers are derated for reclosing duty per the applicable IEEE/ANSI standard.

Previous fault duty analysis revealed four 69 kV breakers at South Fond du Lac substation, and one 138 kV breaker at Tower Drive substation is at their fault interrupting capacity and have been scheduled for replacement by 2011. Additionally, one breaker at Lost Dauphin substation and one breaker at Sherman Street substation are at their fault interrupting capacity and are scheduled for replacement by 2012.

For 2011, a 138 kV breaker at Cornell substation and a second 138 kV breaker at Sherman Street substation are at their fault interrupting capacity and will need to be scheduled for replacement. As new projects are placed in-service analysis is performed to determine if additional breakers are nearing their fault current interrupting capabilities.

Table ZS-7: ATC System Angular Stability Assessment for 2011 10-Year Assessment (as of July 1, 2011)

	Facility Studied	# Units	Total Capacity (MW)	Last Year 0f Detail Study	Response to Selected NERC Category B, C and D Contingencies (NERC Reliability Criteria)				SPS	Note
					2011	2012~2015	2016	Appropriate for 2017~2021		
	Existing Units									
1	Pleasant Prairie	2	1208.0	2007	Acceptable (1,2,3)	Acceptable (1,2,3)	Acceptable (1,2,3)	Yes	No	See notes (4,5)
2	Paris	4	400.0	2008	Acceptable (1,2,3)	Acceptable (1,2,3)	Acceptable (1,2,3)	Yes	No	2008 TYA
3	Oak Creak	7	1138.0	2007	Acceptable (1,2,3)	Acceptable (1,2,3)	Acceptable (1,2,3)	Yes	No	See note (5)
4	Valley	2	280.0	2009	Acceptable (2,3)	Acceptable (2,3)	Acceptable (2,3)	Yes	No	2009 TYA, See note (6)
5	Germantown	5	345.0	2010	Acceptable (3)	Acceptable (3)	Acceptable (3)	Yes	No	2010 TYA, See note (7)
6	Port Washington	6	1080.0	2009	Acceptable (2,3)	Acceptable (2,3)	Acceptable (2,3)	Yes	No	2009 TYA, See note (8)
7	Point Beach	2	512; 514	2009	Acceptable (2,3)	Acceptable (2,3)	Acceptable (2,3)	Yes	Yes	See note (9)
8	Kewaunee	1	579.0	2009	Acceptable (2,3)	Acceptable (2,3)	Acceptable (2,3)	Yes	No	2009 TYA
9	Edgewater	3	773.0	2010	Acceptable (3)	Acceptable (3)	Acceptable (3)	Yes	Yes	2010 TYA, See note (10)
10	S. Fond du Lac	4	352.0	2010	Acceptable (3)	Acceptable (3)	Acceptable (3)	Yes	No	2010 TYA
11	Neevin	2	300.0	2005	Acceptable (20)	Acceptable (20)	Acceptable (20)	Yes	No	2011 TYA
12	De Pere	1	185.0	2010	Acceptable (3)	Acceptable (3)	Acceptable (3)	Yes	No	2010 TYA, See note (11)
13	Pulliam	6	459.0	2005	Acceptable (20)	Acceptable (20)	Acceptable (20)	Yes	No	2011 TYA
14	West Marinette	4	240.0	2009	Acceptable (2,3)	Acceptable (2,3)	Acceptable (2,3)	Yes	No	2009 TYA
15	Fox Energy	3	672.3	2008	Acceptable (1,2,3)	Acceptable (1,2,3)	Acceptable (1,2,3)	Yes	No	2008 TYA, See note (9)
16	Sheboygan Energy	2	343.0	2005	Acceptable (20)	Acceptable (20)	Acceptable (20)	Yes	No	2011 TYA, See note (9)
17	Cypress	88	145.2	2009	Acceptable (2,3)	Acceptable (2,3)	Acceptable (2,3)	Yes	No	2009 TYA
18	Forward Energy Center	86	129.0	2008	Acceptable (1,2,3)	Acceptable (1,2, 3)	Acceptable (1,2,3)	Yes	No	2008 TYA
19	Columbia	2	1050.0	2005	Acceptable (18)	Acceptable (18)	Acceptable (18)	Yes	No	2011 TYA
20	Christiana	3	544.5	2005	Acceptable (19)	Acceptable (19)	Acceptable (19)	Yes	No	2011 TYA
21	Riverside	3	659.1	2010	Acceptable (3)	Acceptable (3)	Acceptable (3)	Yes	No	2010 TYA
22	Rock River	5	132.0	2010	Acceptable (3)	Acceptable (3)	Acceptable (3)	Yes	No	2010 TYA
23	Nelson Dewey	2	226.0	2010	Acceptable (1,2,3)	Acceptable (1,2,3)	Acceptable (1,2,3)	Yes	No	See note (12)
24	University	2	236.0	2008	Acceptable (1,2,3)	Acceptable (1,2,3)	Acceptable (1,2,3)	Yes	No	2008 TYA
25	Concord	4	400.0	2008	Acceptable (1,2,3)	Acceptable (1,2,3)	Acceptable (1,2,3)	Yes	No	2008 TYA
26	West Campus	3	147.2	2009	Acceptable (2,3)	Acceptable (2,3)	Acceptable (2,3)	Yes	No	2009 TYA
27	Presque Isle	5	431.0	2007	Acceptable (2,3)	Acceptable (2,3)	Acceptable (2,3)	Yes	Yes	See note (13)
28	Weston	5	552.6	2005	Acceptable (20)	Acceptable (20)	Acceptable (20)	Yes	No	2011 TYA
26	Elm Road	1	1230.0	2007	Acceptable (1,2,3)	Acceptable (1,2,3)	Acceptable (1,2,3)	Yes	No	See note (5)
	New / Future Units with Signed Interconnection Agreement									
27	EcoMet (wind)	67	100.5	2008	See note (17)	See note (17)	See note (17)	See note (17)	No	See note (14)
22	Glacier Hills (wind)	138	249.0	2009	See note (15)	See note (15)	See note (15)	See note (15)	No	See note (15)
23	Lake Breeze	49	98.0	2004	See note (17)	See note (17)	See note (17)	See note (17)	No	See note (16)

These shaded rows represent units at plants in which there have been a significant system topological change near the plant or significant parameter changes or updates to the dynamic models used in stability studies and are to be studied in the 2011 TYA as part the system angular stability analysis

Notes:

(1) Comparing 2009 TYA models with 2008 TYA models, no significant change has occurred near the generation station, other than the local load growth. Therefore, the stability results from the 2008 TYA are still applicable and are acceptable in the following years.

(2) Comparing 2010 TYA models with 2009 TYA models, no significant change has occurred near the generation station, other than the local load growth. Therefore, the stability results from the 2009 TYA are still applicable and are acceptable in the following years.

(3) Comparing 2011 TYA models with 2010 TYA models, no significant change has occurred near the generation station, other than the local load growth. Therefore, the stability results from the 2010 TYA are still applicable and are acceptable in the following years.

(4) Since 2009 TYA Pleasant Prairie Special Protection System (SPS) study was completed on May 27, 2009 and concluded the SPS was no longer required and could be retired.

(5) "Final Facility Study Update – Revision 2 Phase I, II & III Milwaukee County, Wisconsin MISO #G051 (#36760-01)" dated January 15, 2007.

(6) Replacment of breaker failure relays and breakers required per 2009 TYA.

(7) Addition of redundant bus differential relays and reduction of delayed clearing times required per 2010 TYA.

(8) 2009 TYA Evaluation, Generator Validation Study dated September 8, 2008. River Bend D-T Study Dated December 2010 covers any changes in the local area.

(9) "Final ISIS Report Point Beach Generators Manitowoc County, Wisconsin MISO #G833/J022 (#39297-01), G834/J023 (#39297-02)" dated October 2, 2009. A single NERC Category C9 was evaluated to ensure full compliance with applicable NERC standards.

(10) Addition of redundant bus differential relays required per 2010 TYA.

(11) Addition of redundant bus differential relays and reduction of delayed clearing times required per 2010 TYA.

(12) "Interconnection System Impact Study Report 50 MW Wind Generation Grant County, Wisconsin J084" dated June 24, 2010

(13) "Presque Isle Special Protection System “Remedial Action Tripping Scheme” (RATS)" Version 3.0 dated December 17, 2007. Presque Isle will be re-studied as part of the next SPS review.

Notes (Continued):

(14) "Interconnection System Impact Study Report 99 MW Wind Generation Revision 4; Calumet County, Wisconsin" - MISO #G611 (#38791-01)" dated October 24, 2008.
"Interconnection System Impact Study Report 1.5 MW Wind Generation; Calumet County, Wisconsin" - MISO #G927 (#39423-01)" dated May 16, 2008.

(15) "Interconnection System Impact Study Report 99 MW Wind Generation Revision 3; Columbia County, Wisconsin" - MISO #G706 (#39041-01)" dated September 4, 2008.
"Interconnection System Impact Study Report 150 MW Wind Generation Revision 2; Columbia County, Wisconsin" - MISO #H012 (#39567-01)" dated July 13, 2009.
Glacier Hills will be commercial by the end of 2011 and will be put into the rotation of studied generators beginning with the 2012 TYA study.

(16) "Interconnection Evaluation Study Report 98 MW Wind Generation; Fond du Lac County, Wisconsin" - MISO #G427 (#38121-01)" dated December 22, 2004.

(17) Until a generator declares commercial operation, an assessment of this facility will not be completed as part of the current Ten Year Assessment.

(18) Two NERC Category D3 contingencies resulted in un-acceptable performance for ATC post-contingency voltage recovery criteria. Re-setting breaker failure relays for these contingencies result in meeting applicable ATC planning criteria. No angular instability was identified for these contingencies. All applicable NERC planning criteria was met for these contingencies.

(19) Nine NERC Category D2 and three NERC Category D3 contingencies resulted in un-acceptable performance for ATC stability and post-contingency voltage recovery criteria. Re-setting breaker failure relays for the category D2 and D3 contingencies result in meeting applicable ATC criteria. All applicable NERC planning criteria was met for these contingencies.

(20) No angular or voltage stability concerns were identified for this generator for the 2011 TYA.