MRO 2008-2009 Winter Assessment

Summary

The Midwest Reliability Organization (MRO) is expected to have sufficient generating capacity within the region to maintain an adequate reserve margin for the 2008-2009 Winter peak demand. The transmission system within the MRO region is expected to perform reliably to meet firm customer demand for the 2008-2009 Winter. There are no significant operational issues that may cause reliability concerns expected in the MRO region during the upcoming winter.

MRO 2008-2009 Winter Assessment

Projected Total Internal Demand	43,080	MW
Interruptible Demand & DSM	1,541	MW
Projected Net Internal Demand	41,539	MW
Last Winter's Peak Demand	41,450	MW
All-Time Winter Peak Demand	41,450	MW
Deliverable Internal Capacity	56,349	MW
Firm Purchases	776	MW
Firm Sales	960	MW
Net Capacity Resources	56,165	MW
Capacity Margin	26.0	%
Reserve Margin	35.2	%
With Uncertain Resources		
Total Potential Resources	61,539	MW
Capacity Margin	26.8	%
Reserve Margin	36.6	%

Introduction

The Midwest Reliability Organization (MRO) is expected to have sufficient generating capacity within the region to maintain an adequate reserve margin for the 2008-2009 Winter peak demand. The transmission system within the MRO region is expected to perform reliably to meet firm customer demand for the 2008-2009 Winter. There are no significant operational issues that may cause reliability concerns expected in the MRO region during the upcoming winter.

The MRO is a Cross-Border Regional Entity representing the upper Midwest of the United States and Canada. MRO is organized consistent with the Energy Policy Act of 2005 and the bilateral principles between the United States and Canada. The MRO membership consists of the former

and existing members of the MAPP Generation Reserve Sharing Pool (GRSP), members from the former Mid-America Interconnected Network, Inc. (MAIN),[1] and Saskatchewan Power Corporation (SaskPower), one of the two Canadian members.[2] The transmission assessment and operational issues in this MRO regional self-assessment are, however, presented by geographical areas in the MRO footprint: Iowa, Nebraska, Northern MRO, Saskatchewan, and Wisconsin-Upper Michigan Systems (WUMS). The Northern MRO area consists of the Dakotas, Minnesota, part of Montana, and the Canadian province of Manitoba.

Demand

The MRO forecasted 2008-2009 Winter Non-Coincident Peak Total Internal Demand in the combined MRO US and MRO Canada is 43,080 MW, assuming normal weather conditions. This forecast is 2.1% above last winter's forecasted total demand of 42,204 MW and 3.9% higher than last year's actual winter peak demand of 41,450 MW. Any interruptible demand or DSM implemented during last year's peak load is unknown. The MRO 2008-2009 forecast Net Internal Demand is 41,539 MW, which is 1.9% higher than the 2007-2008 forecasted Net Internal Demand of 40,775 MW. The majority of this demand increase can be attributed to the very rapid load growth in the oil fields and coal bed methane fields in the Bakken Formation in western North Dakota and eastern Montana.

Peak demand uncertainty and variability due to extreme weather and other conditions are accounted for within the determination of adequate generation reserve margin levels. Both the MAPP GRSP members and the former MAIN members within MRO utilize a Load Forecast Uncertainty factor within the calculation for the Loss of Load Expectation (LOLE) and the percentage reserve margin necessary to obtain a LOLE of 0.1 day per year or 1 day in 10 years. The load forecast uncertainty considers uncertainties attributable to weather and economic conditions. Forecasts are developed for Saskatchewan to cover possible ranges in economic variations and other uncertainties such as weather using a Monte Carlo simulation model to reflect those uncertainties.

Each MRO member uses its own load forecasting methodology; some reported 50/50 forecast and some 90/10 forecast. In general, the peak demand forecast includes factors involving recent economic trends (industrial, commercial, agricultural, residential) and normal weather patterns. From a regional perspective, there were no changes in this year's forecast assumptions in comparison to last year.

MRO staff distributed the NERC Winter 2008-2009 data request spreadsheet to each LSE member within the MRO in the format received from NERC. The members populated these spreadsheets based on NERC and MRO instructions and submitted them to the MRO for processing by a predetermined due date. Internally, MRO staff compiled the individual spreadsheet submissions into a set of regional spreadsheets representing the MRO region as a whole as well as MRO U.S. and MRO Canada.

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[1] The former MAIN members are Alliant Energy, Wisconsin Public Service Corp., Upper Peninsula Power Co., Wisconsin Public Power Inc., and Madison Gas and Electric. The American Transmission Company (ATCLLC) is the transmission owner which encompasses the last four former MAIN members and Alliant Energy-Wisconsin Power & Light, which is the Wisconsin portion of Alliant Energy. The ITC Midwest is the transmission provider for the Iowa and Minnesota portion of Alliant Energy.

[2] The other Canadian member is Manitoba Hydro which, for the purpose of this assessment, is included in the MAPP GRSP group.

When the spreadsheet was initially distributed, MRO instructions emphasized to the LSEs that each MW of demand must be counted once and only once and that LSEs should carefully coordinate with their neighboring LSEs to ensure that double-counting would not occur in the regional compilations.

Interruptible Demand (800 MW, 1.8%) and Demand Side Management (DSM) (741 MW, 1.7%) programs, amounting to 3.5% of the MRO's Projected Total Internal Peak Demand of 44,072 MW are utilized by a number of MRO members. A wide variety of programs, including direct load control (such as electric appliance cycling) and interruptible load, may be used to reduce peak demand during the winter season.

Generation

The existing internal certain resources for the MRO US and Canada 2008-2009 winter are 55,587 MW. The existing internal uncertain resources for the MRO US and Canada 2008-2009 winter are 5,190 MW. Planned resources that are expected to be in service this winter are 762 MW. These values do not include firm or non-firm purchases and sales. The month of January was used in all cases to be consistent.

The nameplate capacity of the variable generation for the MRO is 4,924 MW. The variable resources for the MRO expected to be available at peak times is 984 MW, based on 20% of nameplate capacity. This value of nameplate capacity is used by the Midwest ISO when determining capacity of variable generation. It is also used by the MRO Model Building Subcommittee when building peak models.

The biomass portion of resources for the MRO expected to be available at peak times is 310 MW.

Reservoir water levels improved over the 2008 summer, but continue to remain below normal in Montana, North Dakota, and South Dakota, and will likely continue to reduce the magnitude and duration of power transfers out of northern MRO where the hydro resources are located. This will continue to contribute to the imports of power into the MRO region during peak load periods. The Manitoba water condition is normal and normal Manitoba-US transfers are expected. Manitoba Hydro manages its reservoir levels in preparation for the winter season such that there is adequate energy to meet daily energy demand throughout the winter.

SaskPower reservoirs are at normal conditions and regular operating regimes are expected. Reservoir levels are sufficient to meet both peak demand and the daily energy demand throughout the upcoming season.

The MRO region is not experiencing a drought or expecting any other conditions that would create capacity reductions.

The MRO region considers known and anticipated fuel supply or delivery issues in its assessment. Because the region has a large diversity in fuel supply, inventory management, and delivery methods, the MRO does not have a specific mitigation procedure in place to address fuel delivery problems. The MRO members do not foresee any significant fuel supply and fuel delivery issues for the upcoming 2008-2009 winter season. However, if problems occur, they

will be addressed on a case by case basis. Therefore, there should be no apparent impacts to the reliability of meeting peak electrical demand.

Purchases and Sales

For the 2008-2009 winter season, the MRO is projecting total firm purchases of 776 MW from sources external to the MRO region. The MRO has approximately 960 MW of total projected sales to load outside of the MRO region. The net import/export of the MRO region can vary at peak load, depending on system conditions and market conditions.

Transfer capability from MRO Canada (Saskatchewan and Manitoba) into the MRO US is limited to 2,415 MW due to the operating security limits of the two interfaces between these two provinces and the US. The forecasted firm transfers from Manitoba to the US are 873 MW for the winter for 2008-2009.

Throughout the MRO region, firm transmission service is required for all generation resources that are utilized to provide firm capacity; therefore, that these firm generation resources are fully deliverable to the load. The MRO is forecast to meet the various reserve margin targets without needing to include energy-only, uncertain, or transmission-limited resources.

Currently, MRO members do not use Liquidated Damage Contracts as firm capacity resources.

Transmission Reliability Margins are calculated and reserved by the Transmission Providers within the MRO Region to assure that operating reserves can adequately be delivered. These operating reserves can include resources outside of the MRO Region since most MRO members participate in the Midwest Contingency Reserve Sharing Group.

Transmission

The following reinforcements include projects that have expected service dates from June 1, 2008 through December 31, 2008. Projects that went in service prior to June 1, 2008 were listed in the Summer 2008 Assessment.

Iowa

New wind farm generation is planned to be in service prior to (or during) this winter season. This includes new wind farms in Iowa near Adair, Walnut, Crystal Lake, Fernald, McIntire, Iowa Barton Township, Carroll, and Forest City. There was also an addition to the existing Pomeroy/Pocahontas wind farm near Pomeroy, Iowa. Significant new transmission facilities that are planned to be placed into service prior to this winter season include:

- Grimes Tap to Bittersweet Road 161 kV. In service in October 2008
- Replacement of the 345/161 kV transformer at S.E. Polk.
- Monona-Victory 161 kV line upgrade. In service in December 2008.
- Carroll-Drager 161 kV line upgrade. In service in December 2008.
- Drager-Grand Junction 161 kV line upgrade. In service in December 2008.

Nebraska

Phase I of Nebraska Public Power District's Electric Transmission Reliability (ETR) Project for East-Central Nebraska was completed in June 2008. Phase I of the ETR Project entailed conversion to 345 kV of an existing 40 mile 230 kV transmission line from just north of Norfolk to a point just north of Columbus, expansion of the Hoskins Substation near Norfolk and construction of the new Shell Creek Substation north of Columbus. Completion of this phase of the project is expected to improve local area voltage support.

As a part of the Nebraska City Unit 2 power plant project, a new 50 mile 345 kV transmission line from the site of the Nebraska City 2 plant to a new substation southeast of Lincoln was energized in July 2008. The new line is expected to reduce the need for temporary operating guides during critical prior outages in and around Lincoln.

Under the same concept, a new 26 mile 345 kV transmission line that completes a northern tier segment around the city of Lincoln is expected to be energized by end of December 2008. This line is expected to reduce contingent overloading issues on critical assets in the Lincoln area, which in turn, will also reduce the need for temporary operating guides on these facilities.

Northern MRO

The Split Rock – Nobles Co 345 kV line was energized this summer, which completed the Xcel Energy 825 MW wind projects.

A new power plant at Cannon Falls Minnesota has been energized this past summer with a total output of 350 MW. The generating station is connected to the new Colville substation on the Cannon Falls – Empire 115 kV line and Cannon Falls – Spring Creek 161 kV line. As part of this project, Colville – Empire line capacity has been increased to 248 MVA. Several 69 kV lines were also upgraded to provide transmission service.

Xcel Energy has other capacity increases on its system. The capacity of Lakefield Junction – Lakefield generating station 345 kV line will be upgraded from 735 MVA to 918 MVA by the end of 2008 to provide an outlet to generation in Southwestern Minnesota. The Hyland Lake – Dean Lake 115 kV line in the Minneapolis-St. Paul Metro area was increased to 361 MVA this summer. The High Bridge Generating Station capacity increase was completed in the summer with the gross output from the plant at 610 MW. As part of this upgrade, High Bridge – Rogers Lake 115 kV line capacity was increased to 598 MVA.

Minnkota Power Cooperative is currently constructing the Pillsbury – Maple River 230 kV line. This line will serve as generation outlet for a number of wind farms located near Pillsbury, ND, that are currently under construction or in the planning stages. The in-service date is projected to be December 31, 2008.

The Dorsey Bus Enhancement project was completed, which consists of the Dorsey 230 kV bus being improved with the addition of four 230 kV circuit breakers and a new connecting bus. This project reduces the consequences of a category D event occurring at Dorsey station. Also the two lines (K21W & K22W) interconnecting Manitoba to Ontario were upgraded to 100°C design operation.

Saskatchewan

Saskatchewan has no new facilities to report for this season.

Wisconsin-Upper Michigan Systems

The WUMS electric transmission system encompasses the service territories of five Balancing Authorities: Alliant Energy-Wisconsin Power & Light, We Energies, Wisconsin Public Service Corporation, Madison Gas & Electric Company and Upper Peninsula Power Company. The WUMS system consists of 345, 230, 161, 138, 115 and 69 kV transmission facilities and is owned by American Transmission Company, LLC (ATCLLC). The operation of WUMS is coordinated between ATCLLC and Midwest ISO.

There are no transmission additions at 200 kV and above with expected in-service dates between June 2008 and December 2008. Significant upgrades to the 138 kV system are:

- Uprate North Appleton - Lost Dauphin 138 kV line. Already in-service.
- Uprate North Appleton - Mason St 138 kV line. Already in-service.
- Construct Clintonville - Werner West 138 kV line. Expected to be in service in November 2008.

Operational Issues

The MRO members are affiliated with five Planning Authorities: Midwest ISO, MAPP, American Transmission Company, Manitoba Hydro, and SaskPower. Midwest ISO also spans into the RFC and SERC regions. It has recently received approval to begin operation as a single Balancing Authority (BA) area. Midwest ISO operation as a BA is expected to occur in January 2009 as the operation of its Ancillary Service Market begins. There are two Reliability Coordinators within the MRO footprint – Midwest ISO and SaskPower. A number of MRO members are Midwest ISO-tariff members and therefore participate in the Midwest ISO market operations.

The MRO region has approximately 5,000 MW of nameplate wind generation. There is a potential ambient temperature restriction (e.g., some wind turbines can be restricted to operating in ambient temperatures between -20 degrees F and 104 degrees F) with wind turbines and there may be a potential increase in operating reserves that could be required for this wind generation during ambient temperature limitations.

Iowa

Normal and reliable operation of the transmission system is expected in Iowa during the winter 2008-2009 season. A number of scheduled transmission and generation outages will take place in late fall 2008 and early winter 2008/2009 in order to perform regular maintenance or to accomplish scheduled projects. Outage scheduling studies have not identified any serious operational problems. Temporary operating guides will be issued for outages that might cause some loading or voltage concerns, or in case that unforeseen operating conditions and/or winter storm related events bring the system close to its operating limits.

A typical winter flow pattern characterized by a south-to-north system bias is expected to re-occur this winter season. These power transfers from the Southern and Eastern NERC Regions into the Northern MRO Region may cause some TLR/Congestion Management activities. In preparation for this season, the line rating of a flowgate on the South to North transmission path has been up-rated after replacing switches and relays. This upgrade will allow more transfer capability and enhanced reliability of the area.

The Iowa Operating Review Working Group and TOS have approved three new flowgates in Iowa during 2008 and eliminated two existing flowgates. The standing operating guides for all flowgates will be in effect during winter 2008/2009 to assist transmission operators and reliability coordinators in dealing with operational issues.

Nebraska

No significant operational concerns are expected in Nebraska during winter 2008/2009. Where large transfers might occur, operating guides and operating procedures have been put into place to maintain the reliable operation of the Nebraska regional transmission system.

Operational studies have been performed and will be updated as necessary for scheduled transmission and generation outages during the winter peak and off-peak time periods. Temporary operating guides will be issued for those outages which require actions or limitations to protect system operating limits.

In the past, the Nebraska/Iowa regional transmission system has experienced south-to-north transfers due to low hydro conditions and winter peak load conditions in northern MRO. These south-to-north transfers across the MRO system have a more profound impact on the eastern Nebraska system than on the western Nebraska system. All of the flowgates have approved operating guides and have proven effective in dealing with system conditions throughout the year.

Winter season load distributions are considered worst case for western Nebraska area stability. Operating guides have been developed which adequately protect the western Nebraska region for winter season load levels and maximum transfer conditions.

Northern MRO

A typical winter flow pattern characterized by a south-to-north system bias is expected to re-occur this winter season. These heavy south-to-north non-firm power transfers will likely cause some TLR/Congestion Management activities. Overall, the northern MRO system will be able to operate under all load and firm exchange levels while meeting the regional reliability criteria.

A number of bulk transmission outages are scheduled in the Northern MRO US region for maintenance; however no operating problems are expected. Temporary operating guides will be developed as necessary.

Saskatchewan

No significant operational concerns are expected, and operating guides are developed on an ongoing basis to deal with facility outages. Applicable operating guides can be found on the SaskPower OASIS node.

Wisconsin-Upper Michigan Systems

The Arrowhead – Stone Lake – Gardner Park (aka Arrowhead – Weston) 345 kV line went in service in January 2008; it improves the WUMS transmission reliability and transfer capability between Minnesota and Wisconsin. With the 345 kV line in-service, a new interface, the Minnesota Wisconsin EXport (MWEX) interface has been defined, which is comprised of Arrowhead-Stone Lake 345 kV line and King-Eau Claire 345kV line. The west to east transfer through the MWEX interface is constrained due to potential transient voltage recovery violation and voltage instability. The MWEX interface is managed as a reciprocal Interconnection Reliability Operating Limit (IROL) Flowgate of Midwest ISO and MAPP. An operating guide is in place which defines MWEX limits under system intact and various N-1 prior outage conditions.

The WUMS southern interface includes tie lines in the southwest and southeast interfaces. The southwest interface comprises the Wempletown – Paddock 345 kV line and Wempletown – Rockdale 345 kV line. The southeast interface comprises Zion – Arcadian 345 kV line, Zion – Pleasant Prairie 345 kV line and Zion – Lakeview 138 kV line. The WUMS southern interface is thermally limited for critical N-1 contingencies and voltage stability limited for critical N-2 contingencies during periods of heavy imports through the interface. An operating guide is in place that helps to manage these constraints.

Operating studies have been or will be performed for all scheduled transmission or generation outages. When necessary, temporary operating guides will be developed for managing the scheduled outages to ensure transmission reliability.

There are no known environmental or regulatory restrictions that could impact reliability during the 2008-2009 winter season.

Reliability Assessment Analysis

The MRO Reliability Assessment Committee is responsible for this 2008-2009 winter assessment. However, the MRO Transmission Assessment Subcommittee, the MRO Resource Assessment Subcommittee, the MAPP Transmission Operations Subcommittee, ATCLLC, and Saskatchewan Power Corporation all contribute to the preparation of the assessment. At the first step, MRO staff sent the NERC spreadsheets to the registered entities within the MRO and collected individual entity's load forecast, generation, and demand-side management data. The staff then combined the individual inputs from these spreadsheets to calculate the MRO regional totals. The staff also sought responses to the questions included in the NERC seasonal request letter, from Planning Authorities within the MRO region – MAPP, ATCLLC, and SaskPower. The MAPP Transmission Operations Subcommittee provided operational issues review from the various MAPP operating review working groups. Using all the information gathered from the process, the MRO Resource Assessment Subcommittee prepared the resource assessment portions, while the MRO Transmission Assessment Subcommittee prepared the transmission

assessment and operational issues portions. Finally, the MRO Reliability Assessment Committee reviewed and approved the final draft before it was submitted to NERC.

Reserve margins are typically used as criteria for a target level as opposed to capacity margins. The MRO's projected 2008-2009 Winter Reserve Margin is 35.2% without Uncertain Resources.

For the MAPP GRSP members, resource adequacy is measured through the accreditation rules and procedures. The MAPP GRSP requires a 15% reserve capacity obligation (RCO) for predominantly thermal systems, and 10% reserve margins for predominantly hydro systems.[3] The RCO is established by the MAPP Restated Agreement and its governing authorities, i.e. MAPP Executive Committee and MAPP Pool Committee. This level of reserve requirements is subject to periodic review based on reserve requirements studies conducted regularly by MAPP.[4] The RCO requires the MAPP GRSP members to maintain their respective minimum reserve based on after-the-fact peak demand; i.e., the members are responsible for maintaining adequate generation to account for load forecast uncertainty. When a new peak occurs, the member will be required to maintain the minimum reserve based on that peak for the next 11 months, or until a new, higher peak takes place. Approximately 8,850 MW of generation in the MAPP GRSP (15.7% of MRO net internal capacity) is associated with predominantly hydro systems and only requires a 10% RCO.

For the former MAIN members, generation resource adequacy is assessed based on LOLE studies previously conducted by the MAIN region.[5] Although conducted on a yearly basis, MAIN's LOLE studies consistently recommended a minimum short-term planning reserve margin of 14%. Most recently, the Midwest Planning Reserve Sharing Group shows a required reserve margin of 14.2% for western MISO.

Saskatchewan's reliability criterion is based on annual expected unserved energy (EUE) analysis and equates to an approximate 13% reserve margin requirement.[6]

The projected MRO reserve margin of 35.2% for the 2008-2009 winter season is in excess of the above target Reserve Margins. This projected reserve margin, which includes only Certain Resources and net interchange, can be compared with last winter's projected reserve margin of 34.4% (considering committed resources and net interchange). With Uncertain Resources, the projected reserve margin is 36.6%, as compared to 34.6% for winter 2007-2008 with uncommitted resources included.

There are likely some differences in the way members submitted their generation data due to the significant changes in generation definitions in 2008. Additionally, variable generation (wind in particular), up to its nameplate capacity, was included as Uncertain Resources. Also, purchases

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[3] The MAPP GRSP Handbook, http://www.mapp.org/assets/policies/grsp_handbook_20080617.pdf.

[4] The previous MAPP reserve requirements study was conducted in 2003 by the MAPP Composite System Reliability Working Group. This study has not been posted on the MAPP website, but it is available upon request from MAPPCOR. The MAPP 2008 LOLE Study is ongoing and is expected to be completed by December 1, 2008.

[5] In the former MAIN region, MAIN Guide 6 adopted a resource adequacy criterion of 0.1 days/year, http://www.maininc.org/bg/guide6.pdf. Studies concerning LOLE calculations for the former MAIN Region are available. The 2005 study is located at http://www.maininc.org/files/MG6GenerationReliabilityStudy2005_14.pdf. Other studies are found by navigating through http://www.maininc.org/files/files.htm.

[6] Saskatchewan Power's generation adequacy studies for the province of Saskatchewan are not publicly posted or released. Information regarding these studies may be obtained by contacting SaskPower .

and sales in 2007-2008 included purchases from IPPs within the MRO footprint since that is how data was previously collected. For 2008-2009 Winter, MRO staff attempted to include all IPP capacity as an internal resource, not as a purchase. Most large IPPs that are registered as Generator Owners MRO were properly captured. However, there are smaller IPPs that fall below registration criteria that have not been entirely captured. These additional IPPs would likely increase the projected capacity and reserve margins by an insignificant amount.

Generation deliverability is performed by Transmission Providers within the MRO region. Links to deliverability criteria within the MRO region are:

http://www.midwestiso.org/page/Generator+Interconnection

http://www.mappcor.org/content/policies.shtml

https://www.oatioasis.com/spc/

Throughout the MRO region, firm transmission service is required for all generation resources that are utilized to provide firm capacity; therefore, that these firm generation resources are fully deliverable to the load. The MRO expects to meet the various reserve margin targets without needing to include energy-only, uncertain, or transmission-limited resources.

There are no known deliverability concerns with the various methods used within the MRO region for firm deliverability.

No specific analysis is performed to ensure external resources are available and deliverable. However, to be counted as firm capacity the MAPP GRSP, former MAIN utilities, and Saskatchewan require external purchases to have a firm contract for capacity and firm transmission service.

The following discussion is based on the MRO/RFC/SPP/SERC-W 2008-2009 Winter Inter-regional Assessment.[7]

Non-simultaneous Total Import Capabilities into MRO from RFC-W, SERC-W, and SPP Regions:

Transfer Direction	TIC (MW)
RFC_W TO MRO	3064
SERC_W TO MRO	3764
SPP TO MRO	3164

The Total Import Capability (TIC) is equal to the net import into MRO (1964 MW) in the base case plus the First Contingency Incremental Transfer Capability (FCITC) obtained in the transfer analysis. These studies recognize constraints internal and external to the MRO.

[7] Eastern Interconnection Reliability Assessment Group (ERAG) Winter 2008-2009 Inter-regional Transmission Assessment, MRO-RFC-SERC West-SPP (MRSWS) sub-group study (on-going), http://www.midwestreliability.org/

Transient, voltage and small signal stability studies are performed as part of the near-term/long-term transmission assessments.[8] Voltage stability is also evaluated in the Midwest ISO's seasonal assessment.[9] The results of the Midwest ISO winter assessment were not available prior to the due date of this regional assessment. Reactive power resources are considered in on-going operational planning studies. No transient, voltage, or small signal stability issues are expected that impact reliability during the 2008-2009 winter season.

Several members within the MRO region have localized UVLS programs to prevent localized low voltage conditions. No UVLS has been installed in the MRO region to protect the Bulk Electric System.

Other Region-Specific Issues that were not mentioned above

There are no other known reliability concerns anticipated within the MRO region for 2008-2009 Winter.

Region Description

The Midwest Reliability Organization (MRO) has 48 members which include Cooperative, Canadian Utility, Federal Power Marketing Agency, Generator and/or Power Marketer, Small Investor Owned Utility, Large Investor Owned Utility, Municipal Utility, Regulatory Participant and Transmission System Operator. The MRO has 119 registered entities. The MRO Region as a whole is a summer peaking region. The MRO Region covers all or portions of Iowa, Illinois, Minnesota, Nebraska, North and South Dakota, Michigan, Montana, Wisconsin, and the provinces of Manitoba and Saskatchewan. The total geographic area is approximately 1,000,000 square miles with an approximate population of 20 million.

[8] 2008 MAPP System Performance Assessment; and MAPP Small Signal Stability Analysis Project Report, June 2007.
[9] Midwest ISO Winter 2008-2009 Assessment Studies (in progress), http://extranet.midwestiso.org/operations/seasonal.php

MODEL BUILDING SUBCOMMITTEE REPORT

Date: November 19th, 2008

To: MRO Reliability Assessment Committee (RAC)

From: Alan Burbach, Chairman MRO Model Building Subcommittee

Re: Development of MRO 2009 Series Models

The Model Building Subcommittee (MBS) held a face-to-face meeting on October 29th. Later this year the Subcommittee will set its meeting dates for the year 2009, and it is anticipated that there will be four scheduled meetings.

MBS MEMBERS

Adam Flink, MRO, Secretary	Wayne Haidle, BEPC
Dan Jesberg, MRO, Alt. Secretary	Wayne Roelofs, GRE
Dustin Betz, NPPD	Holli Krizek, WAPA
Alan Burbach, LES Chairman	Gerry Lane, MH
Dan Burns, CIPCO	Rao Konidena, MISO
Dan Custer, MEC Vice Chairman	Srinivas Vemuri, XEL
Kristian Samoila, SPC	Kerry Marinan, ATC
Justin Jorgensen, ITC	Hamish Wong, WPS

MRO 2008 Series

The completion of the 2008 Series is expected by the scheduled RAC meeting date. We anticipate receiving the dynamic models from MISO staff in the first few days of November, and the MBS will review the dynamics data for a flat start. Although the preliminary power flow models were posted on September 25 for general use, we may receive additional idev updates to apply to these models that are related to the development of the dynamic models. The idev files will be posted along with the final power flow models.

MRO 2009 Series

The 2009 Series models will be developed based on PSS/E Rev 30.3, which is consistent with the version used for the MRO 2008 Series and is also consistent with the next model series to be developed by the ERAG MMWG.

The MBS previously approved the following list of models to be developed in their 2009 Series. This set of models contains all the models required by the MMWG, as well as three additional models

unique to the MRO Series (shown in bold). The 2009 Series will contain 15 models, reduced from 16 models in the 2008 Series.

MRO 2009 Series	MMWG 2008 Series External Data
2010 Spring Light Load	2009/10 Winter
2010 Spring Peak	2009/10 Winter
2010 Summer Peak	2010 Summer
2010 Summer Shoulder 70% Peak	2010 Summer
2010/11 Winter Peak	2009/10 Winter
2011 Spring Peak	2009/10 Winter
2011 Summer Peak	2010 Summer
2011 Fall Peak	2010 Summer
2011/12 Winter Peak	2009/10 Winter
2015 Summer Peak	2014 Summer
2015 Summer Shoulder 70% Peak (*)	2014 Summer
2015/16 Winter Peak	2014/15 Winter
2020 Summer Peak	2014 Summer
2020 Summer Shoulder 70% Peak (*)	2014 Summer
2020 Winter Peak (*)	2014/15 Winter

Notes: * Unique MRO Series model.

The model development schedule has been modified and includes the following key milestones:

- Data Request Sent Out — December 1, 2008
- Finalize Company Workbooks — February 6, 2009
- Power Flow and Dynamics Model Data Due — February 20, 2009
- Post (Pass1) Solved Power Flow Models — March 27, 2009
- Changes to Pass 1 models — April 10, 2009
- Post (Pass 2) Solved Power Flow Models — May 1, 2009
- Changes to Pass 2 models due — May 15, 2009
- Final Series Power flow Models Posted — June 19, 2009

The significant changes to the schedule include (1) completing the company workbooks (i.e., transactions) before the data submission date, (2) moving the data submission date forward from early March to February 20, and (3) moving the model series completion date forward from July 18 to June 19.

The MBS in cooperation with MISO staff had the Data Reps review and update the MOD base case in order to establish an accurate base case model. This base case is starting point for the development of all the MRO series models. The base case update was performed over the October 24 to November 5 time period.

Wind Generation Modeling Task Force (WGMTF)

The WGMTF completed its mission, which was:

"to research and develop guidelines for consistent wind generation modeling to be used in the analysis of the reliability of the interconnected transmission system. The WGMTF is responsible for creating a User Manual on wind generation modeling, which will provide guidance in evaluating and selecting wind generation models for use in power flow and dynamic models built by the MRO-MBS. The guidelines and procedures contained in this User Manual are intended to minimize modeling discrepancies and improve the wind generation modeling for MRO reliability assessments."

The MBS, in agreement with the WGMTF, passed a motion to terminate the task force. The ongoing wind modeling objectives will now be subsumed by the MBS.

Other Business

- The MBS discussed issues associated with NPPD and OPPD leaving the MRO model building and joining the SPP model building. However, the discussion resulted in more questions than answers, so the MBS will address concerns as they arise. A few items, like a modified list of inter-regional tie lines, were identified and will be developed early in the model building process.
- MDU will become its own load balancing authority in the 2009 Series, and work has begun to make this modification to the MOD base case.
- Adam sent out a request to the Data Representatives to supply long bus names for a Data Dictionary. This task has been completed.
- MRO User Models with no documentation have been identified. Now the next step is to identify the owners and have them provide the necessary documentation.
- The MBS will begin with the 2009 series to collect machine reactive capability data in order to improve the accuracy of its annual series of power flow models. At this time there are no NERC compliance obligations with this data request.

Submitted by:
Alan D. Burbach
Model Building Subcommittee Chairman

Resource Assessment Subcommittee (RAS)

REPORT

November 19, 2008

Midwest Reliability Organization

Resource Assessment Subcommittee (RAS)

- **RAS Meetings: (After 08-28-2008 RAC)**
  - September 17, 2008 (Web Conference)
  - September 23, 2008 (RAC Web Conference)

Resource Assessment Subcommittee (RAS)

- **RAS Meeting Highlights:**
  - September 17, 2008 Web Conference
  - MRO-RAS completed a "Draft" of the RAS portion of the NERC 2008/09 Winter Assessment which was due to NERC by September 30, 2008.
  - September 23, 2008 RAC Web Conference
  - RAC reviewed and discussed the NERC 2008/09 Winter Assessment.

Resource Assessment Subcommittee (RAS)

- **Future RAS Meeting Schedule:**
  - No Future Meetings scheduled at this time.

Resource Assessment Subcommittee (RAS)

- **Other RAS Business:**
  - Tim Owens with Nebraska Public Power District (NPPD) has tendered his resignation as Vice-Chairman of the RAS due to NPPD leaving the MRO and joining SPP
  - RAS will need to elect a new Vice-Chairman and then fill the vacant position on the RAS.

Resource Assessment Subcommittee (RAS)

- **Questions ?**

Subcommittees and Task Forces

- Scenario Assessment Task Force (SATF)
  - SATF last met on October 13. Two additional guests from MISO and Jeff Mitchell from RFC participated in this SATF meeting. Major discussions include:
    - **Assumptions for the Base Scenario and Wind Scenario**

      The group continued the discussions regarding what are the appropriate assumptions for the base scenario and wind scenario. The group discussed the two alternative assumptions (19.4% of energy from wind and 27.4% of energy from wind in 2017 in MRO footprint). The group generally agreed that the assumption of 19.4% of 2017 energy from wind may be more appropriate. The 27.4% assumption for the 2017/2018 time frame may be too aggressive when considering the transmission needed to be in-service within the time frame.

      MRO staff also provided an overview of the MRO 2008 LTRA data in spreadsheets. The group discussed possible changes in assumptions used in the spreadsheets that could potentially lead to data assumptions needed for the wind scenario assessment.
    - **MRO footprint data in the JCSP study**

      MISO participants presented the data (demand, generation, wind related data, etc) specific to the MRO footprint, as requested by the group previously. This helps relate the wind assumptions to be used in the transmission portion of the assessment and the demand and generation portion of the assessment.

Subcommittees and Task Forces

- Scenario Assessment Task Force (SATF) (Cont.)
  - SATF last met on Oct. 13: (Cont.)
    - **Outline of responsibilities for various questions in the NERC scenario assessment request**

      The NERC questions can be categorized into three major groups – demand and generation related, transmission related and operation related. Chair presented the initial proposal of lead persons (MRO staff and SATF members) for various NERC questions, portions in the scenario assessment request. The group was agreeable to the assigned responsibilities.

      The group carried out good discussions while going through the NERC questions. The group also noted that some questions do not make sense and it may be reasonable not to spend much time for such questions.

      The group discussed that the MRO collected data will be used for the portions of the assessment that address demand, generation and energy. The JCSP study will be discussed qualitatively for the portions of the assessment that address transmission. The discussion of operation issues will be based on MISO wind farm operating experience, Minnesota wind integration study, JCSP study, etc.
    - **Next step**

      SATF is scheduled to meet again on December 17. The agreed upon lead persons will lead the more detailed discussions for various portions of the wind scenario assessment.

Subcommittees and Task Forces

- Transmission Assessment Subcommittee
  - Meeting Highlights
    - October 14, 2008 face-to-face meeting
      - **PRC-012 and -014 MRO procedures drafts**

        The group had a lengthy discussion of the latest revisions of the PRC-012 and -014 MRO procedures. Brian Brownlow of NPPD had worked on the latest revisions on behalf of TAS. Brian has contributed good amount of time and effort for this work and the end product was very much appreciated by the entire TAS group. After the review by TAS, the drafts were passed on to both PRS and TAS for the joint call on October 17.
      - **Draft schedule for reviewing the existing SPS**

        TAS and MRO staff also discussed the draft schedule for reviewing the existing SPS that MRO staff put together. A number of action items were noted: MRO will send separate tables (xls files) to the existing SPS owners within MRO to collect the information of "last review dates". MRO staff will then perform additional work in revising the review schedule. PRS and TAS will review and approve the final schedule.

1

Subcommittees and Task Forces

- Transmission Assessment Subcommittee (Cont.)
  - Meeting Highlights
    - Joint call with PRS on Sept. 23 and Oct. 17
      - **PRC-012 and -014 MRO procedures drafts**

        The two groups has had two conference calls after the joint meeting on August 26, working on the draft MRO procedures for PRC-012 and -014. Members from both groups have put in good efforts to go through various revisions. During the joint call on October 17, the two groups have come at a consensus and approved the final drafts.

2

Eastern Interconnection Reliability Assessment Group

Draft for Comment Meeting Minutes
Management Committee Meeting
Renaissance Ross Bridge Hotel, Birmingham, AL

August 7, 2008 (1:00 p.m. - 5:00 p.m.)
August 8, 2008 (8:00 a.m. – noon)

Agenda

ERAG Management Committee

Jay Caspary (Vice-Chair SPP)
Carter Edge (SERC)
Bill Harm (RFC)
Hoa Nguyen (MRO)
Jeff Mitchell (Chair-RFC)
Vince Ordax (FRCC)
Paul Roman (NPCC)
Russ Schussler (SERC)
John Seidel-telephone 8/8 (MRO)

Additional Attendees

Dennis Chastain (MRO-RFC-SERC west-SPP Western Forum Chair, TVA)
Chuck Chakravarthi (Southern Company)
Gaurav Karandikar (MMWG, Ameren)
Scott Lockwood (SERC East-RFC, AEP)
Don Reichenbach (SERC East-RFC Chair-Duke)
Harvey Scribner (MMWG-Chair, SPP)
Hari Singh (American Transmission)

1. Introductions and Logistics

2. Approve minutes for:

The minutes from the April 23-24, 2008 were approved as final and will be issued and posted on the ERAG web site.

The notes from the April 28, 2008 conference call were approved as final and will be issued and posted on the ERAG web site.

3. Review Administrative Items

a). Rosters

There were no changes to the ERAG Management Committee roster. **Paul Roman will send out the erag Management Committee exploder list addresses for review.** NPCC maintains the RFC-NPCC exploder lists but has no longer maintained the old vem lists. NPCC can maintain other forum exploder lists if requested to do so. Roster changes to steering committee rosters were reported.

b). Web site

c). Chair and Vice Chair Rotation

Jeff Mitchell's term as Chair will end on December 31, 2008. Jay Caspary (Vice-Chair) is now slated to take over as Chair at that time. Volunteers to take over as Vice-Chair were requested. **The members will check in their organizations to see who can volunteer for the Vice-Chair position.**

d). Other issues

An addition will be made to the ERAG Management Committee handbook to include content on the release and approval of reports done within the Study Forums.

The members agreed that the ERAG Study Forum Assessments would likely qualify as Critical Electric Infrastructure Information (CEII). **Jeff Mitchell will prepare a draft of an item indicating this to place in the handbook.**

4. Study forum issues:

a). Report from each forum on future studies conducted, any gaps in studies, and recommendation for how to proceed:

i. Western (MRO-RFC-SERC west-SPP)

Dennis Chastain reported on the MRO-RFC-SERC west-SPP forum assessment status. The 2008/09 winter assessment work is on schedule.

ii. Northeastern (NPCC-RFC)

Paul Roman reported on the SERC East-RFC forum assessment status. The development of the 2008/09 winter base case is about 2 weeks behind schedule but it is still very early and the work is expected to get on track. Manpower concerns were the main impediment to conducting a future assessment.

iii. Southeastern (SERC east-RFC)

Don Reichenbach reported on the SERC East-RFC forum assessment status. The 2008/09 winter assessment work in on schedule.

b). Discuss possible joint forum future study

The need for an ERAG future study or future studies in each forum was discussed. Jeff Mitchell cited Section 800 in the ERO Rules and Procedures which calls for future assessments. Jeff suggested an approach to satisfy this in 2009 is to have each forum conduct a summer assessment and bypass the winter assessment to free up manpower to conduct a future study. The Joint Coordinated System Plan (JCSP) study is more extensive than that approach; it looks much further into the future and meets a different need than the individual studies.

The usefulness of the findings of the present form of the seasonal studies, 5 year future assessments and longer term assessments was discussed. The recent use and application of the results of the present seasonal assessments was questioned. ERAG Management Committee members expressed some reservations about continuing in the same manner. Scott Lockwood indicated that in RFC there are stakeholders that have considerable interest in the reports and the results.

The ERAG Management Committee suggested that the Steering Committee chairs survey their members and stakeholders to determine their needs in seasonal, near-term future and long term future assessments. Completion of interregional seasonal and future assessments is required by NERC standard TPL-005. Feedback to the ERAG Management Committee will be provided prior to the next meeting. Some suggestions to consider included:

- Shoulder peak results may be more useful to operators than peak load.
- Skip or do an abbreviated 2009/2010 winter assessment and concentrate on completing a near-term future assessment in year 2009.

c). Discuss MC approval of assessment reports

A proposal was made to have the ERAG Management Committee formally approve the Steering Committee reports. Presently the ERAG MC provides comments to the final drafts of the assessment reports but does not formally approve them. The proposed approval procedure would include mailing of final drafts of the reports to the ERAG MC and presentation of the results to the ERAG MC. Concerns were voiced with the timing to get final drafts of the assessments completed to coincide with scheduled ERAG MC

April/May and October/November meetings. An alternative approach could be approval by e-mail if meetings could not be scheduled during the time when the assessment reports are completed. Input on this question will be sought through the Steering Committee surveys of stakeholders.

d). Discuss handling of inter-Regional RTOs in the studies

The RFC-NPCC forum studies transfer capabilities between PJM and NPCC and between NPCC and the RFC portion of MISO. It does not study transfers from and to RFC as a whole or the entire MISO market. This practice was discussed.

This question will be handled as part of the planned survey to get feedback.

Gaurav Karandikar pointed out that AMEREN transactions that are between PJM and MISO are not accounted for in future studies because COM Ed and AMERREN are the ones who dispatch. The problem is that real transactions which cause loading concerns at the seams are not captured.

e) Other joint and common forum issues

5. ERAG/MMWG involvement in disturbance analyses

The extent of the involvement of the ERAG MC in disturbance analyses was discussed. ERAG contact lists have been provided to NERC to establish contacts for NERC to use in seeking data and other information for disturbance analyses. The MMWG has put into place case quality improvement procedures to remedy the case deficiencies previously indicated by NERC. These measures should be satisfactory and no additional measures are planned.

6. ERAG coordination of facilities map – Discussion of an ERAG effort to coordinate updates of Regional maps. – John Seidel will lead discussion

John Seidel had suggested that the development of an Eastern Interconnection map would save significant time and effort for the individual regions to represent the system areas external to their regions. The ERAG Management Committee agreed to share the PDF versions of all their existing maps but not develop a single Eastern Interconnection map.

7. MMWG issues:

a). Review issues and discuss 2008 Series activities:

Harvey Scribner reported.

<u>i. Power flow cases</u>

- Interchange tables have been updated.
- 8/8 due date for Data Set 2.

- Separate appendix added for raw data docu checks. (Bob Cummings requested items for cleaner cases)
- Cases not solving well yet (Data Set 1).

b). Report progress to incorporate Procedural Manual, Appendix H data checks into the power flow case development process

Harvey mentioned the Regional Raw Read/Warning Data. The data checking status is:

- The regional coordinators are directed to correct the following errors that the PSSTME READ activity indicates as warnings before submitting data to the Power Flow Coordinator.
  - A. Qmax < Qmin
  - B. Pmax < Pmin
  - C. Pmax < Pgen, except for area swing
  - D. Bus X has no generator slot assigned
  - E. Switched shunts with no blocks

c). Status report on power flow database work with Powertech Labs and development of the database itself

The overall Data Base development effort is about two months behind the projected schedule. Real system data is now being used to test the data base tool. Power Tech is going through mock data base populating and data error checking. Harvey provided the status for the specific database development milestone features:

- There is a Configurable Database design that allows for future enhancements to stored data.
- Completed importing power flow base case; users will now be able to import a full series of MMWG cases. The Power Flow Database can include either the partial or entire ERAG system
- Completed importing both tie lines and area interchanges
- Data diagnostic function is applied when importing power flow data
- Capable of supporting multiple power flow cases for a series
- Merge region, tie line, area interchange data features added
- Completed the exporting power flow base case feature
- Completed error reporting addition
- GUI (50% completed)
- Comparison of series power flow data (50% completed)
- Data checking support in progress--Deliverable August 30, 2008

d). Report progress on a process to figure out how to produce a five-year case that meets all the appendix data check requirements incorporated into the series within the budget that is allotted.

Harvey indicated the MMWG proposal for this:

- A five-year case is developed as part of the MMWG model series.
- As part of the MMWG model series development all the appendix data check requirements will be incorporated.

e). Report progress made for the role of the database coordinator, how data changes that occur due to verification checks get coordinated with the regional coordinator, etc.

Database Coordinators will confirm with Regional Coordinators the changes that occur due to verification checks before they are implemented in the database.

f). Report on the progress to develop a detailed power flow database implementation plan. The implementation plans should include:

MMWG Database Testing

Harvey reported that Power Tech proposed to do database testing by working as the MMWG data coordinator to build the 12 models in the 2009 series of MMWG base cases. They would demonstrate the viability of the database and work out any deficiencies through this process and would charge $75,000. ERAG members agreed that Power Tech should not be the Data Coordinator in 2009 and that the existing agreement requires sufficient testing and population of the database before delivering the database to MMWG as a completed product. ERAG has been billed and paid $25,000 of the $100,000 total so far. There should be no additional payment beyond the $100,000 to Power Tech for the completion of the database. Jeff Mitchell suggested that Power Tech use the 2008 MMWG Data Set 1 base cases to populate and test the database to confirm that it is working properly. Power Tech can build and debug 2 or 3 Data Set 1 base cases and compare them to the corresponding cases developed by the MMWG.

MMWG will need to review all items in the contract with Power Tech to confirm that all terms have been fulfilled at the time Power Tech delivers the database as a complete product.

Additional actions for MMWG include:

1. Proceed to finalize the database to ensure the desired product is delivered.
2. Ensure that Power Tech completes necessary database testing and debugging.
3. Populate the database.
4. Conduct training on the use of the database.

5. Have Regional MMWG Coordinators make use of and test the data base to ensure that it is OK.
6. Consider any special concerns with the use of the database by non-PPS/e users.
7. Determine if there are any data transfer concerns.

The ERAG Management Committee needs to research and determine future actions needed for updating the database to be compatible with future PSS/e Revisions.

Power Tech Database Phase 2 Proposal

Harvey also discussed a database Phase 2 proposal from Power Tech. Phase 2 would allow web access to the database, a dynamics database, integration and hardware and additional software licenses. Phase 2 of the database would cost $120,000, which is double the original estimate.

i. Role of power flow database coordinator (when would an RFP need to be issued and what it needs to include?)

The database coordinator will need to:

- Resolve all tie line discrepancies with the regional coordinators
- Update the master power flow database using the modifications provided from regional coordinators
- Merge the power flows
- Check the interchange in the merged case against the MMWG Scheduled Interchange Matrix
- Solve the power flows and do more testing

ii. How members are going to interface with the database once it is available?

Ways to interface with the database include:

- Regional Coordinator can use the power flow database to check submitted data
- Provide changes to a power flow case or provide an entire power flow to the power flow coordinator to update the master power flow database

iii. How best to proceed with the database development once the database is available?

MMWG next steps in database development after Phase 1 would include:

- PSS/e batch command support
- More PSS/e IDEV support
- Move window GUI to web GUI
- Power flow database security

iv. How this database will interface with the dynamics database?

MMWG dynamics interface direction:

- Launch System Dynamics Database
- Consider access to dynamics data from the power flow database

v. Describe how the submittal of data via an SQL server could streamline the above process and provide a recommendation on how and when the SQL server development should proceed.

- Any changes made from one member will be immediately be available for other members.
- Data base will have storage of data base changes for 3 series (possibly 36 base cases).

vi. Describe how the database would modify the role of regional coordinators and data submitters.

- For Phase 1, the database would modify the role of regional coordinators by making them responsible for uploading the data to in-house copies of the database for error checking
- Regional coordinator-corrected data is then submitted to the database coordinator

g. Report on the progress to develop a work plan and timeline for the 2009 case development, since Phase I of the database project should be available

- 2009 Series will be built by the present MMWG Coordinator (AEP)
- Use previously set schedule
- Use the same process as in 2008
- Use a parallel case building process
- Utilize the power flow database
- Do a full comparison between corresponding base cases developed by the Power Flow Coordinator and the base cases by the Power Flow Database Coordinator
- Complete a model reconciliation and power flow database update

- Post final models from the Power Flow Coordinator by the October 2009 MMWG Meeting
- Issue RFP by February 2009
- Select Power Flow Database Coordinator May 2009
- Conduct training on the use of the power flow database
- Build Spring 2010 Models with the power flow database
- Benefits include: 1) refined case building process and workflow, 2) determine areas for further improvement in the power flow database and 3) 2010 MMWG power flow database Coordinator will benefit from a tested process

h. Discuss any other issues

Next MMWG Meeting

- Tampa, Florida
  - 10/27/2008, 1 – 5 PM
  - 10/28/2008, 8 – 12 Noon
- PDDB training
  - 10/28/2008, 1-5 PM

8. Review Future Conference Call and Meeting Schedule

a). Scheduled October 21-22, 2008 (noon to noon) – Toronto, ON downtown

The meeting was cancelled.

b). Schedule other meetings/calls, as needed

Conference calls will be held instead of the planned face to face meeting. Calls will be scheduled for Tuesday, October 21 from 2 to 4 PM EST (ERAG MC issues-Joint studies and future study, seasonal studies status, new ERAG Chair) and Wednesday, October 22 from 9 to 11 EST (MMWG issues-approval 2009 case list, data base development and implementation status).

c). 2009 meeting schedule

A meeting in March 2009 will be planned during the conference calls.

9. Other Issues--Joint Coordinated System Plan (JCSP)

Jay Caspary presented the status of JCSP and described the conceptual plans for large transmission additions (765 kV + HVDC + other). It is a very extensive study. Some key items include:

- An interim stakeholders meeting was held on August 14.
- The 2018 reliability assessment model is the basis for the JCSP study work.

- JCSP also includes year 2024 qualitative analysis using alternative scenarios.
- Economics is the focus of the evaluation.
- By law 5% of energy requirements by 2024 need to be served by renewables.
- There is a 2024 wind scenario.

Prepared by:
Paul A. Roman
Draft for Comment minutes issued on October 15, 2008.

Eastern Interconnection Reliability Assessment Group

Management Committee

Conference Call
October 21, 2008
2:00 p.m. ET (1:00 p.m. Central)

DRAFT

Minutes

Introductions – Jeff Mitchell, chair, brought this meeting of the Committee to order. There were 11 of the 12 Committee members represented on the call, which constituted a quorum. The call attendees are listed in Attachment A.

1. **Study forum issues:**
   a. Report from each forum:
      i. Western (MRO-RFC-SERC west-SPP) – Dennis Chastain reported on the progress of the winter study.

      ii. Northeastern (NPCC-RFC) – Ken Thomas reported on the progress of the winter study.

      iii. Southeastern (SERC east-RFC) – Don Reichenbach reported on the progress of the winter study.

   b. Discuss possible joint forum future study – with a unanimous voice vote, the Committee decided that each of the three ERAG forums would conduct a near-term future study in 2009 to replace the normal winter study. These studies would be performed during the normal winter schedule; therefore, no winter studies will be performed for 2009/10. The study forums will develop the study scopes and keep the Committee informed of their progress. Paul Roman mentioned that NPCC wants to perform a future study in early 2009 to satisfy some state requests. NPCC can coordinate this effort with PJM and/or RFC if it does not coincide with the ERAG study.

   c. Other joint and common forum issues – the Committee discussed how wind generation is modeled and re-dispatched for the studies. The Committee asked the study committees for advice on how to dispatch the wind generation in the study cases and the MMWG to provide proposals on how it should be modeled in the cases (and include language in the MMWG procedural manual).

2. **Discuss MMWG Activities**
    a. Status report on power flow database work with Powertech Labs – John Idzior provided a status report on the progress to complete the project. Powertech is currently behind schedule now, but the project should be completed by in the near future. The MMWG will have to determine when Powertech has met the terms of the contract so that final payment can be made.

    b. *Approve* the 2009 Series power flow and dynamics base case list - with a unanimous voice vote, the Committee approved the case list, which is shown in Attachment B.

    c. Report on the work plan and timeline for the 2009 case development – John reported that the MMWG plans to use the traditional process along with the new database in 2009.

    d. Report on the progress to develop a detailed power flow database implementation plan – the MMWG continues to develop this process and will provide more information later. The plan is to begin sole use of the database in 2010.

    e. Discuss internal regional base case release policies – John Seidel mentioned the MRO's policy for release of their base cases that are additional to the MMWG cases and asked if other Regions had similar issues. After some discussion, the Committee directed the MMWG to review the base case release policy to determine if changes are required.

3. **Select Chair and Vice Chair for next two-year term (2009-2010)** – Jay Caspary informed the Committee that he would be replaced next year by Bruce Rew and asked if the Committee would accept Bruce as the chair for the next term. The Committee unanimously selected Bruce Rew as chair for the 2009-2010 term and also unanimously selected John Odom as vice chair for the same term.

4. **Proposed 2009 Conference Call and Meeting Schedule** – the Committee approved the following schedule for 2009:
    a. Call to discuss 2010 budget – March 10, 2009 at 10:00 a.m. ET
    b. Meeting on July 30-31, 2009 (noon to noon) – with SERC pig roast in St. Louis
    c. Other meetings/calls as needed

5. **Other Items**

a. Paul Roman distributed a draft of the August meeting minutes for Committee review on October 15, 2008. The Committee approved those minutes subject to minor changes made by October 24th to Paul.
b. SERC announced that David Till of TVA would replace Russ Schussler for the 2009-2010 term.
c. From the August meeting agenda regarding maps, the Committee asked that each region's map(s) be sent to Jeff by October 31 so that he may package them together and distribute it to the ERAG regions after that.

The call was adjourned at 4:15 p.m.

Draft by J. Mitchell – October 27, 2008

Attachment A

ATTENDANCE LIST

FRCC – John Odom; Vince Ordax
MRO – John Seidel; Ed Weber
NPCC – Paul Roman, Mike Falvo
RFC – Bill Harm; Jeff Mitchell
SERC – Russ Schussler, Carter Edge, Herb Schrayshuen
SPP – Bruce Rew, Jay Caspary
Others – John Idzior, RFC staff, representing the MMWG
Ken Thomas (PJM), northeastern forum study committee chair
Don Reichenbach (Duke), southeastern forum study committee chair
Dennis Chastain (TVA), western forum study committee chair

Attachment B

Eastern Interconnection Reliability Assessment Group

Multiregional Modeling Working Group

2009 Series Model Selection

Year	Season	Power Flow Data Set I	Power Flow Data Set II	Dynamics	ERAG Study Models
2010*	Light Load	X		X	
2010	Spring		X		
2010	Summer	X		X	X
2010	Summer Shoulder	X		X	
2010/11	Winter	X		X	X
2011	Spring		X		
2011	Summer	X		X	
2011	Fall		X		
2011/12	Winter		X		
2015	Summer	X		X	
2015/16	Winter	X		X	
2020	Summer		X		

Note: *This version has only incremented the model by 1 year.
Data Set I & II models have not been determined.

Agenda 14.a.
NERC Reports
Data Coordination Working Group

From: Owens, Timothy J. [mailto:tjowens@nppd.com]
Sent: Thursday, October 23, 2008 2:16 PM
To: Nguyen, Hoa
Cc: John A. Seidel; Daniel P. Jesberg; Sunneberg, Jon M.
Subject: Resignation - NERC DCWG

Hoa Nguyen
Chair, MRO Reliability Assessment Committee

Dear Hoa,

As you are no doubt aware, NPPD has provided notice of its intention to withdraw from the MRO and join SPP, both effective April 1, 2009. With this in mind, I believe it is appropriate for me to tender my resignation as an MRO representative to the NERC Data Coordination Working Group (NERC DCWG).

I have enjoyed the opportunity to represent the MRO on the NERC DCWG over the last couple of years. I am confident that Dan Jesberg will continue to provide excellent representation for the MRO and I wish him much success.

Sincerely,

Tim Owens
Resource Planning & Risk
Nebraska Public Power District
Ph: 402-563-5526; FAX: 402-563-5511
E-mail: tjowens@nppd.com

Agenda 14.d.
NERC Reports
Operating Committee

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(1)
From: LLarson@otpco.com [mailto:LLarson@otpco.com]
Sent: Monday, September 29, 2008 4:30 PM
To: mro-assess@midwestreliability.org
Subject: [mro-assess] NERC Operating Committee report

RAC members,

The NERC OC September meeting actions were:

1. Approved a revised committee charter. This was mostly administrative and adding technical approval of the Functional Model.

2. Reviewed the status of the proposed reliability standard PER-005-1. This is out for 30 pre-ballot review. If passed, it will require several changes to many MRO member programs.

3. Approved the initial membership of the Reliability Fundamentals Working Group tasked with overseeing the maintenance of the Reliability Concepts document.

4. Discussed the impacts of the committee and its subgroups on the NERC budget and recommended ways of reducing costs. One thing under consideration is to reduce the number of face-to-face meetings.

5. Began preliminary discussions related to the development of the committee's 2009-2011 work plan. A group was formed to bring a revised plan to the December meeting.

6. Approved the technical content of version 4 of the Functional Model. Concerns with the Interchange Authority will be addressed in version 5.

7. Approved the WECC reliability plan, subject to WECC receiving reliability coordinator certification. The WECC will move from three RCs to one RC operating out of two locations starting January 1, 2009.

8. Reviewed the proposed Operational Reliability section of the Long-Term Reliability Assessment. This is a section on trends in Reliability, both Operational Reliability and Adequacy.

At the Joint OC/PC/CIP meeting there was a presentation on the Threat & Incident Reporting Guideline. The Appendix A to the guideline contains a helpful reporting matrix. I have attached a copy to this report.

<<Threat-Incident_Rptg_Guideline_EffDate_1Apr08_Rev_29July08.pdf>>

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Lawrence R Larson, P E
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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Minutes
Operating Committee

September 10–11, 2008
Doubletree Hotel Seattle Airport
Seattle, Washington

Convene

A regular meeting of the NERC Operating Committee (OC) was held on September 10–11, 2008, in Seattle, Washington. The meeting notice, agenda, and attendance list are affixed as **Exhibits A**, **B**, and **C**, respectively; and individual statements and minority opinions as **Exhibits D** and **E,** respectively. The meeting presentations are posted in a separate file at http://www.nerc.com/~filez/ocmin.html.

Operating Committee chairman Gayle Mayo convened the meeting at 1 p.m.

Secretary Larry Kezele announced that a quorum was present.

Antitrust Compliance

The secretary referred the committee to the NERC Antitrust Compliance Guidelines included in the meeting agenda.

Consent Agenda

The committee approved the June 4–5, 2008 meeting minutes.

Meeting Highlights

The Operating Committee:

1. Approved a revised committee charter.
2. Reviewed the status of the System Personnel Training Standard Drafting Team.
3. Approved the initial membership of the Reliability Fundamentals Working Group tasked with overseeing the maintenance of the *Reliability Concepts* document.
4. Discussed the impacts of the committee and its subgroups on the NERC budget and recommended ways of reducing costs.
5. Began preliminary discussions related to the development of the committee's 2009-2011 work plan.
6. Approved the technical content of version 4 of the Functional Model.
7. Approved the WECC reliability plan, subject to WECC receiving reliability coordinator certification.
8. Reviewed the proposed Operational Reliability section of the Long-Term Reliability Assessment.

FYI

Board of Trustees — Chairman Mayo summarized discussions at the July 30, 2008 Board of Trustees meeting, especially those related to the Electricity Sector Steering Group (ESSG) charter, staffing a senior executive as the "Chief Security Officer" who will serve as a single point of contact for the industry, the ESSG, and government stakeholders seeking to communicate with NERC on cyber and infrastructure security matters, and approval of a change to the charter of the Transmission Owners and Operators Forum to increase diversity of membership.

Reliability Fundamentals Working Group — At its June 2008 meeting, chairman Mayo tasked the Nominating Subcommittee with soliciting members to serve on the Reliability Fundamentals Working Group (RFWG). Subcommittee chairman Mark Fidrych reported that the subcommittee recommends appointing Stephen Lee (EPRI), Steve Myers (ERCOT), Francis Halpin (BPA), Ali Chowdhury (University of Missouri – Rolla), Peter Brandien (ISO-NE), and Jerry Rust (Northwest

Power Pool) to the RFWG. Chairman Mayo accepted the subcommittee's recommendations and noted that the RFWG scope was included in the agenda material.

Committee Charter Revisions

The secretary reviewed proposed revisions to the committee's charter related to approval of the Functional Model and committee membership (e.g., terms and proxies). *Jim Griffith moved to approve the revisions to the Operating Committee charter*. The committee approved the motion.

NERC Budget – Impact of Committee and Subgroup Meetings

Chairman Mayo summarized discussions of the Standing Committees Coordinating Group and the committee's executive committee related to the reduction of costs associated with conducting committee and subgroup meetings. Examples include:

- Eliminating some joint meetings and/or conducting some joint meetings by WebEx
- Holding one-day committee meetings
- Recommending that subgroups hold their meetings at company or Regional Entity offices, thus eliminating hotel meeting room costs
- Merging the Operating and Planning Committees

Following a brief discussion of the merits of each of the above examples, chairman Mayo stated that the committee's executive committee would further address this topic.

Operating Committee Work Plan

Chairman Mayo stated that the committee's current work plan was approved at its December 2007 meeting and that she asked vice chairman Holeman to lead a discussion of this topic at this meeting (**Presentation 1**). Following a brief discussion related to the need to revise the work plan and topics that the work plan should encompass, chairman Mayo appointed vice chairman Holeman, Jerry Rust, Tom Bowe, Jim Griffith, and Lorne Midford to review and revise the work plan for discussion at the committee's next meeting.

Future Path of Transmission Loading Relief

Tom Mallinger, MISO, summarized the history of the Eastern Interconnection's transmission loading relief (TLR) procedure (**Presentation 2**). Mr. Mallinger noted that the TLR procedure:

- Is the primary congestion management procedure used over the last 10 years, and that only minor modifications have been made to the procedure during this time.
- Is used when significant, externally induced parallel flows make local procedures insufficient to control facility loading.
- Relies on e-Tag curtailments to curtail non-firm usage and a combination of e-Tag and network and native load (NNL) relief obligations to curtail firm usage (share-the-pain approach).

However, use of the TLR procedure has resulted in industry complaints related to:

- Implementation of the TLR procedure can result in a large number of e-Tag curtailments for a small amount of relief; thus, use of TLR is disruptive to the markets and has resulted in entities scheduling around bottlenecks.
- The NNL relief obligation is based on a static set of assumptions contained in the interchange distribution calculator (IDC). As such, the IDC does not rely on real-time generator, load or net interchange information.
- Because the NNL calculation is based on static assumptions, reliability coordinators lack visualization of the magnitude and source of parallel flows when they experience congestion.

To address these industry complaints, Mr. Mallinger stated that MISO, PJM, and SPP submitted a standard authorization request (SAR) that would require all Eastern Interconnection reliability coordinators to report their generator-to-load impacts to the IDC on a real-time basis. Hence, a reliability coordinator experiencing congestion would have visualization of the magnitude and source of all flows affecting their congested flowgate using information in the IDC.

Mr. Mallinger noted that the Operating Reliability Subcommittee (ORS) and the Reliability Coordinator Working Group discussed the proposed SAR. While neither group endorsed the concept, they did ask for a cost/benefit analysis of the proposal.

Functional Model Version 4

As a follow-up to the Functional Model Working Group's report at the joint session, chairman Mayo asked if the committee had any questions of working group chairman Jim Cyrulewski. The committee expressed concerns related to the Interchange Authority, which Mr. Cyrulewski noted would be more thoroughly addressed by the working group during its development of version 5. *Mark Fidrych moved to approve the technical content of version 4 of the Functional Model and the Functional Model Technical Document.* The committee approved the motion.

Events Analysis

Bob Cummings, director events analysis and information exchange, highlighted the following events currently being analyzed (**Presentation 3**):

1. Eastern Interconnection Frequency Disturbance – August 4, 2007 — Analysis team is editing the final report, which will have limited distribution due to critical infrastructure sensitivities. Mr. Cummings outlined the follow-up recommendations resulting from the analysis.
2. MRO System Separation – September 18, 2007 — Analysis team is writing semi-final report. Although the report is not yet final, Mr. Cummings outlined the preliminary follow-up recommendations from the analysis.
3. FRCC South Florida Disturbance – February 26, 2008 — FRCC analysis team is writing the final report.
4. RFC PEPCO Disturbance – June 13, 2008 — Reliability*First* is forming an event analysis team.

5. SPP Southwestern Public Service Company Separation – June 17, 2008 — The analysis of this event is just beginning.

Integration of Variable Generation Task Force Report – Operational Perspective

As a follow-up to the Integration of Variable Generation Task Force report at the joint session, task force chairman Warren Frost noted that the Planning Committee requested a summary of best practices be included in the final report. The committee suggested that the task force report will help educate various industry stakeholders (e.g., industry regulators) regarding the technical challenges of implementing variable generation resources. The committee also requested the task force to address the operational details of all limited energy resources (e.g., wind generation and demand-side management). The task force anticipates presenting its preliminary report to the committee at its December 2008 meeting. Chairman Mayo noted that the committee will take action on the proposed recommendations after it has received the final report.

WECC Reliability Plan

Linda Perez, WECC managing director of reliability coordination, summarized the WECC revised reliability plan and efforts to consolidate the three WECC reliability coordinators (Pacific Northwest Security Coordinator, Rocky Mountain–Desert Southwest Reliability Coordinator, and California-Mexico Reliability Coordinator) into one reliability coordinator with operating desks in Loveland, Colorado, and Vancouver, Washington (**Presentation 4**). Ms. Perez noted that there will be visual links between the two operating centers and that the transition is scheduled to occur on January 1, 2009.

Operating Reliability Subcommittee vice chairman Frank Koza stated that the ORS reviewed the revised WECC reliability plan and endorsed it for presentation to the Operating Committee. *Tom Bowe moved to endorse the WECC Reliability Coordinator Plan, contingent upon WECC receiving NERC reliability coordinator certification prior to the expected January 1, 2009 startup.* The committee approved the motion.

Boreas Vulnerability Working Group

Chairman Mayo reviewed a memorandum from Michael Assante, NERC's chief security officer, regarding a request for assistance in the formation of a Boreas Vulnerability Working Group. The request notes that NERC, in its function as the ES-ISAC, issued an advisory dated August 27, 2008, describing Boreas (a computer vulnerability that affects industrial control systems). The working group, in conjunction with the Department of Homeland Security and the National Cyber Security Division, will develop a greater understanding of the technical issues, evaluate potential technical impacts, and assess the need for providing additional information. Chairman Mayo asked for committee volunteers to serve on the working group.

Continuing Education Program

Martin Sidor, director of training, education, and personnel certification, highlighted efforts to revise the Continuing Education Administrative Manual (**Presentation 5**). The manual outlines the continuing education program process and rules, including provider rules. The manual was last updated in 2007. Mr. Sidor will post the manual for a 30-day comment period in late September 2008 and inform the committee of the results of that posting at its December meeting.

Underfrequency Load Shedding Relays

Vice chairman Holeman stated that the 2003 blackout report contained recommendations related to the implementation and coordination of underfrequency load shedding relay programs. He noted that some university researchers are asking if such programs are coordinated across Regional Entity boundaries. The committee noted that Regional Entities are coordinating the implementation of underfrequency load shedding relays within their Region in accordance with reliability standards. Furthermore, requirement R1.1 of PRC-006-0 (Development and Documentation of Regional UFLS Programs) requires "…coordination of UFLS programs within the subregions, Regional Reliability Organization and, where appropriate, among Regional Reliability Organizations."

Adjourn and Reconvene

The committee adjourned at 5:09 p.m. PDT and reconvened the following morning at 8:02 a.m.

Resources Subcommittee

Terry Bilke, chairman of the Resources Subcommittee, lead the committee in a discussion of the following topics (**Presentation 6**):

- Frequency Performance — Mr. Bilke noted that the increase in the number of smaller frequency excursion is a direct result of a continuing decline in the Eastern Interconnection frequency response. In addition, an analysis of the data suggests that the majority of larger frequency excursions (greater than 0.05 Hz) occur during time corrections.

- NAESB Time and Inadvertent Management — Mr. Bilke highlighted FERC concerns, as expressed in Order 693, with inadvertent balances, and NERC and NAESB efforts to address those concerns. For example, NAESB is considering a different approach to implementing time error corrections.

- Process for Addressing FERC Requests and Questions — As chairman of the Resources Subcommittee, FERC has requested access to NERC reliability tools and access to data generated by those tools. Chairman Mayo noted that FERC cannot be granted access to NERC reliability tools until the Canadian data issue is resolved. She suggested that the committee's executive committee review and respond to each request prior to action being taken by any of the committee's subgroups.

- Performance Standard Reference Document — Mr. Bilke reviewed proposed revisions to the Performance Standard Reference Document and explained that the purpose of the document is to provide instruction for calculating a balancing authority's control performance. The committee noted that, while the document contains a compliance disclaimer, the word "compliance" is used repeatedly. The committee debated whether the document should be a technical reference document to support implementation of a reliability standard, or a committee-approved guideline. Chairman Mayo asked the secretary to research each of these alternatives and to report his findings to the executive committee.

Long-Term Reliability Assessment

Mark Lauby, manager of reliability assessments, provided an overview of the new operational reliability section of the Long-Term Reliability Assessment (**Presentation 7**). The objectives of the operational reliability section include:

- Collect and monitor industry-wide data that can be used to assess industry trends in maintaining reliable performance of the bulk power system.
- Assess the reliability significance and causes of any statistically significant adverse industry trends, determine if the trends represent an actual degradation in overall industry reliability performance, and respond appropriately to any reliability issues that may be identified.
- Communicate industry-level information to stakeholders in an effective and timely manner.

The operational reliability section was reviewed by the Reliability Metrics Working Group and the Reliability Assessments Subcommittee. Some of the proposed metrics include the number of bulk power system disturbances by severity and year, the number of transmission loading relief events resulting in interruption to firm load, and the number of energy emergency alert events. The committee expressed concerns that the operational reliability section was Eastern Interconnection centric, and suggested other potential sources of data (i.e., market monitor reports) that address areas of congestion management in significantly more detail. Mr. Lauby will redraft the operational reliability section for further committee review.

Reliability Readiness Program

Kevin Conway, reliability readiness evaluator, summarized the expected transition of the reliability readiness program through the first quarter of 2009 (**Presentation 8**). In July 2008 the Board of Trustees approved version 3 of the NERC budget, thus approving the phase out of the reliability readiness program by the end of the first quarter of 2009. All reliability coordinator, balancing authority, and transmission operator reliability readiness evaluations scheduled during the fourth quarter of 2008 were cancelled. Mr. Conway noted that program staff will continue working with the Operating Reliability Subcommittee to review and finalize for posting potential examples of excellence.

Chairman Mayo thanked the Mr. Conway and Ms. Jessica Bian for their quality work since the program was initiated in response to the 2003 blackout. The committee acknowledged their accomplishments with applause and congratulations.

Reliability Metrics Working Group

As a follow-up to his presentation at the joint session, Jason Shaver, chairman of the Reliability Metrics Working Group (RMWG), reviewed the working group's recommended metrics to support the Long-Term Reliability Assessment (**Presentation 9**). Mr. Shaver noted that in 2009 the RMWG would 1) continue its development of a metrics framework using the draft white paper "Toward Ensuring Reliability: Reliability Performance Metrics" as input, and 2) identify adequate level of reliability metrics and associated underlying data requirements.

System Personnel Training Standard Drafting Team

Patti Metro, chairman of the System Personnel Training Standard Drafting Team, reviewed proposed reliability standard PER-005-1 (System Personnel Training) (**Presentation 10**). The purpose of PER-005-1 is to ensure that system operators performing real-time, reliability-related tasks on the North American bulk power system are competent to perform those reliability related tasks. When PER-005-1 becomes effective, PER-002-0 (Operating Personnel Training) and certain requirements in PER-004-1 (Reliability Coordinator – Staffing) will be retired. The drafting team anticipates posting PER-005-1 for 30-day pre-ballot review in September 2008 followed by a 10-day ballot.

Next Meeting

The next meeting of the Operating Committee will be on December 3–4, 2008 in Orlando, Florida.

Adjourn

There being no further business before the Operating Committee, chairman Mayo adjourned the meeting on Thursday, September 11, 2008 at 9:33 a.m. PDT.

Larry Kezele
Larry Kezele
Secretary

Angie Nicastro

From: Rocio Wong [Rocio.Wong@nerc.net]
Sent: Tuesday, July 22, 2008 3:35 PM
Subject: REVISED MEETING: NERC September 2008 Standing Committee Meetings

Exhibit A

NERC
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Standing Committee Meetings
September 9-12, 2008 | Seattle, WA

CORRECTED DATES IN TABLE BELOW

Doubletree Hotel Seattle Airport
18740 International Boulevard
Seattle, WA 98188 (Map)
(206) 246-8600
Please call the hotel directly to book reservations

$179 night group rate | Code: NERC
Hotel cut-off date: August 19, 2008 (Rooms booked after this date will be subject to full price, if available)
Room block available from: 9/9 – 9/11 (limited guest rooms available)
Check in: 3 PM – Check out: 12 PM
Dress Code: Business Casual

Group Name	Registration Link	Tuesday, September 9	Wednesday, September 10	Thursday, September 11	Friday, September 12
REMG & Committee Officers	Not required		7 – 9 AM		
Operating Committee	Joint OC	**Exec Committee:** 4:30 – 7 PM	**Joint:** 9 AM – 12 PM **OC:** 1 – 5 PM	8 AM – 12 PM	
Planning Committee	Joint PC	**Exec Committee:** 4:30 – 7 PM	**Joint:** 9 AM – 12 PM **PC:** 1 – 5 PM	8 AM – 12 PM	
Critical Infrastructure Protection Committee	Joint CIPC		**Joint:** 9 AM – 12 PM	8 AM – 5 PM	8 AM – 12 PM

Schedule includes other associated NERC meetings.

View/print announcement in .pdf format

Rocio Wong
Meeting Planner
North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com
rocio.wong@nerc.net

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit B

Agenda
Operating Committee

September 10, 2008 | 1–5 p.m.
September 11, 2008 | 8 a.m.–noon
Doubletree Hotel Seattle Airport
18740 International Boulevard
Seattle, Washington
206-246-9600

Item	Leader	Action
1. Administration	Secretary	
a. Quorum		
b. Procedures		
c. Introduction of Members and Guests		
d. Agenda	Chairman	Approve
2. Consent Agenda	Chairman	Approve
a. Minutes of June 4–5, 2008 meeting		
3. FYI		
a. NERC Board of Trustees	Chairman	
b. Reliability Fundamentals Working Group	Mark Fidrych	
4. Committee Charter Revisions	Secretary	Approve
5. NERC Budget – Impact of Committee and Subgroup Meetings	Chairman	Discussion
6. Operating Committee Work Plan	Vice Chairman	Discussion
7. Long-Term Reliability Assessment	William Bojorquez and Mark Lauby	Approve

continued…

Item	Leader	Action
8. Functional Model Version 4.0	Jim Cyrulewski and Mark Fidrych	Approve
9. Integration of Variable Generation Task Force Report – Operational Perspective	Warren Frost	Discussion
10. Future Path of Transmission Loading Relief	Tom Mallinger	Discussion
11. Reliability Readiness Program	Jessica Bian and Kevin Conway	Discussion
12. Reliability Metrics Working Group	Jason Shaver and Jessica Bian	Discussion
13. Continuing Education Program	Martin Sidor	Information
14. System Personnel Training Standard Drafting Team	Patricia Metro	Discussion
15. WECC Reliability Plan	Linda Perez	Approve
16. Events Analysis	Bob Cummings	Discussion
17. Resources Subcommittee	Terry Bilke	
a. Frequency Trends		Information
b. NAESB Time and Inadvertent Interchange Management		Information
c. Performance Standards Reference Document		Approvel
18. Underfrequency Loading Shedding Relays	Vice Chairman	Discussion
19. Next meeting – December 3–4, 2008 (Orlando, FL)	Secretary	

Exhibit C

ATTENDEES
Operating Committee Meeting
September 10–11, 2008

OFFICERS

Chairman	Gayle Mayo
Vice Chairman	Sam Holeman
Secretary and Staff Coordinator	Larry Kezele

MEMBERS

VOTING MEMBERS

Investor-Owned Utility	Jim Griffith (for Marty Mennes) Paul B. Johnson
State/Municipal	Blaine Dinwiddle
Cooperative	Chris Bolick Mark Fidrych
Federal/Provincial	Tom Irvine Lorne Midford Louis-Omer Rioux Brett Fisher (for David Buck)
Transmission Dependent Utility	Dennis Florom Raymond Phillips
Merchant Electricity Generator	Ralph Honeycutt
Electricity Marketer	Matt Greek Stephen McCullough
ISO/RTO	Tom Bowe Jim McIntosh Warren Frost

VOTING MEMBERS (contd)

FRCC	Eric Senkowicz (for Ron Donahey)
MRO	Larry Larson
NPCC	Jerry Mosier
RFC	Jacqueline Smith
SERC	John Troha (for Jim Griffith)
SPP	Jim Useldinger
WECC	Jerry Rust

NON-VOTING MEMBER

Provincial	Mark Lamothe

ATTENDEES — Operating Committee Meeting (cont)
September 10–11, 2008

Regional Entity

NPCC	Edward Schwerdt

NERC STAFF

Jessica Bian	Mark Lauby
Kevin Conway	Marty Sidor
Bob Cummings	Tom Vandervort

GUESTS

Larry Akens	TVA
Don Badley	Northwest Power Pool
Terry Bilke	Midwest ISO
Peter Brandien	ISO New England
Larry Bugh	RFC
Marc Butts	Southern Company
Roman Carter	Southern Company
James Castle	New York ISO
John Ciza	Southern Company Generation
Julian Cox	National Grid
Jim Cyrulewski	JDRJC Associates
Ed Davis	Entergy Services
Dave Folk	FirstEnergy
Will Franklin	Entergy
Jeff Gillen	American Transmission Co.
Scott Kinney	Avista
Frank Koza	PJM
Kevin Largura	NIPSCO
Ben Li	Ben Li Associates
Thanh Luong	FERC
Tom Mallinger	Midwest ISO
Jason Marshall	Midwest ISO
Patti Metro	NRECA
Katy Onnen	SPP
Don Pape	WECC
Linda Perez	WECC
Dan Schoenecker	MRO
Robert Schwermann	OATI
Jason Shaver	American Transmission Company
Bob Tallman	E ON US
Luke Weber	We Energies
Eric Whitley	WECC

Exhibit D

Individual Statements
Operating Committee Meeting
September 10-11, 2008

There were none.

Exhibit E

Minority Opinions
Operating Committee Meeting
September 10-11, 2008

No minority opinions were offered for the record.

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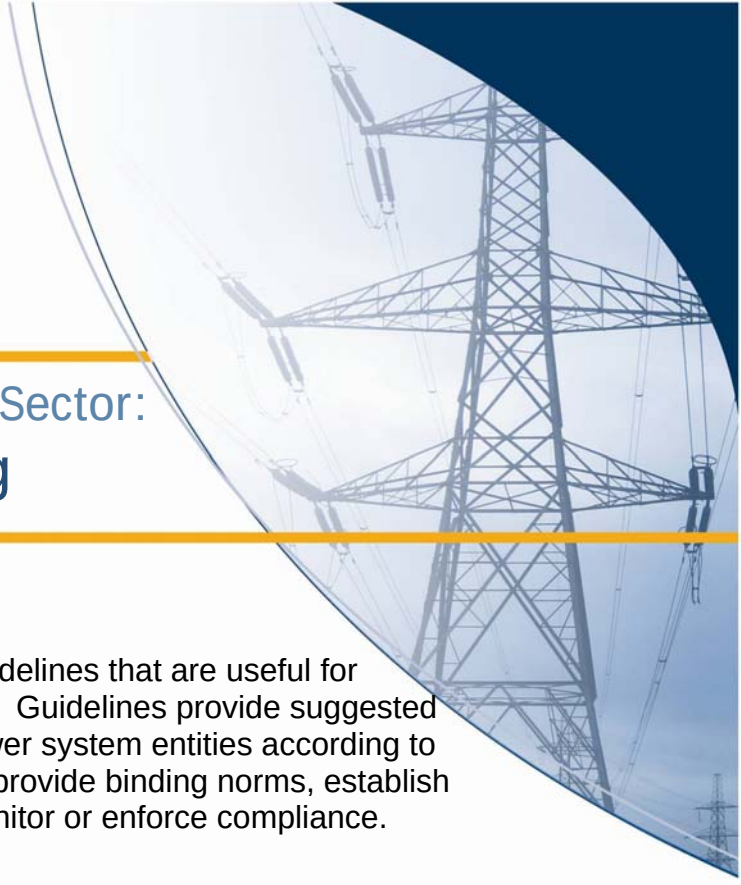

Security Guideline for the Electricity Sector:
Threat and Incident Reporting

Preamble:
It is in the public interest for NERC to develop guidelines that are useful for improving the reliability of the bulk power system. Guidelines provide suggested guidance on a particular topic for use by bulk power system entities according to each entity's facts and circumstances and not to provide binding norms, establish mandatory reliability standards, or be used to monitor or enforce compliance.

Purpose:
The criteria described in this guideline are intended to assist entities to identify and classify incidents for reporting to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). These criteria include, but are not limited to, reporting requirements imposed by some NERC standards (e.g., CIP-001, CIP-008, and EOP-004) and the U.S. Department of Energy (DOE) (OE-417) and requests for voluntary reporting from the U.S. Department of Homeland Security (DHS) and Public Safety Canada/Royal Canadian Mounted Police (RCMP) (a cross-reference is included as Appendix A).

This guideline also identifies available reporting mechanisms.

Operated by NERC, the ES-ISAC serves the electricity sector by facilitating communications between electricity sector entities, U.S. and Canadian federal governments, and other critical infrastructure sectors. The ES-ISAC promptly disseminates threat indications, analyses and warnings to assist electricity sector entities to evaluate the situation and take appropriate actions.

Scope of Application:
This guideline focuses on incidents that have adversely affected or have the potential to adversely affect the reliability of the bulk power system. It is intended for use by owners, operators, and users of the bulk power system.

The criteria in this guideline are not requirements, nor should they be construed as such. This guideline does not supersede reporting required for power system operation or as required by law.

Version 2.0
Effective Date: April 1, 2008

Approved by:
Critical Infrastructure Protection Committee

This document replaces the DHS/ES ISAC Indications, Analysis, and Warning Program Standard Operating Procedure (IAW SOP), dated August 19, 2005. It also replaces the Threat and Incident Reporting Guideline, dated June 2003.

Guideline Details:

The following list describes incidents that entities should consider reporting to the ES-ISAC. Entities can also consider submitting reports to their respective regional entity.

While there are many observable events on the bulk power system, not all need to be reported. It is up to each entity to classify and identify incidents that are most likely to have a detrimental effect on the reliability of the bulk power system should they occur and to develop procedures to report them to the ES-ISAC. This guideline contains criteria and thresholds to assist entities in these activities. For reference, Appendix A is a summary of these criteria in tabular form.

Refer to the reference documents for detailed explanations of reporting definitions and time frames.

Entities are encouraged to report any incident whose cause is known to be malicious, is suspected of being malicious, or is unknown. Moreover, entities are encouraged to report incidents as soon as practical.

Event category: EMERGENCY ACTIONS

1. Public Appeal — An official request by a utility, U.S. regulatory agency, or U.S. government entity that the public reduce its consumption of electricity.

   Report when: an appeal has been issued.

   Report within: 1 hour of the appeal being issued.

2. Voltage Reduction — An entity intentionally lowers the voltage on its system in order to reduce demand.

   Report when: operator-initiated reductions of 3 percent or more are applied system wide.

   Report within: 1 hour after the reduction was initiated.

3. Firm Load Shedding — The intentional outage of customer load in significant quantities either through automatic or operator-initiated actions to protect the bulk power system.

Report when: anticipated or actual disconnection of 100 MW or more occurs.

Report within: 1 hour of the start of the shedding incident.

4. Relocation of Control Center Operations — Transfer of operational control to an alternate site or a return of control to a primary control center.

   Report when: the need to transfer control is out of operational necessity, rather than for the purposes of testing or training.

   Report within: 2 hours of the start of relocation.

Event category: SYSTEM DISTURBANCES

1. Loss of Firm Load — The unintentional outage of firm customer load, including distribution load.

   Report when:
   - 300 MW or more is lost for more than 15 minutes, or,
   - More than 50,000 customers or more are affected for an hour or more.

   Report within: 1 hour (300 MW) or 6 hours (50,000 customers).

2. Forced Outage — A loss of or required removal from service availability of a generating unit, transmission line, or other equipment due to unanticipated reasons.

   Report when:
   - the forced outage is due to an actual or suspected physical attack on a generation or transmission asset, or
   - the forced outage of a generation asset 500 MW or above is due to unknown causes, or
   - a forced outage of generation of more than 2,000 MW occurs in the Eastern or Western Interconnection, or
   - a forced outage of generation of more than 1,000 MW occurs in ERCOT, or
   - the forced outage causes the loss of a transmission facility, significantly affecting the integrity of interconnected system operations, or

- an analysis of the outage results in any of the following actions:
  a. modification of operating procedures.
  b. modification of equipment (e.g., control systems or special protection systems) to prevent reoccurrence of the event.
  c. identification of valuable lessons learned.
  d. identification of non-compliance with NERC standards or policies.
  e. identification of a disturbance that is beyond recognized criteria, i.e., three-phase fault with breaker failure, etc.

Report within: 24 hours of outage or upon taking action as a result of outage analysis.

3. Frequency Excursions — A significant change in the interconnection frequency that occurs suddenly or over a period of time.

   Report when: the excursion is below the underfrequency load shed point for firm loads.

   Report within: 24 hours of the excursion.

4. Voltage Excursions or Collapse — A significant change in the voltage that occurs suddenly or over a period of time.

   Report when: excursion is +/- 10% of nominal voltage or is below undervoltage load shed point.

   Report within: 24 hours of excursion.

5. Islanding or Separation — Part or parts of an interconnection remain(s) in operation following the separation of normally interconnected areas.

   Report when: islanding or separation occurs.

   Report within: 1 hour of occurrence.

6. Complete System Failure (Blackout) — Complete operational failure or shutdown of an entity's transmission or distribution electrical system or both.

Report when: transmission or distribution electrical system experiences a complete operational failure or shutdown.

Report within: 1 hour of failure.

Event category: SABOTAGE/TAMPERING/VANDALISM – Physical or Cyber

1. Security Breaches:
    a. Physical Perimeter Compromise — Unauthorized access of a person or a device through, circumventing, or damaging the physical perimeter or security systems protecting the physical perimeter.

        Report when: unauthorized physical access to facilities, systems, or equipment (such as critical assets or critical cyber assets) that could impact the reliable operation of the bulk power system; or, intentional damage to security systems that protect the physical perimeter.

        Report within: 1 hour of detection.

    b. Cyber Perimeter Compromise — Unauthorized ingress or egress through the electronic perimeter or into an electronic perimeter device.

        Report when: unauthorized electronic access to cyber assets whose impairment could impact the reliability of the bulk power system occurs.

        Report within: 1 hour of detection.

    c. Information Theft or Loss — Unauthorized removal of an item of value.

        Report when: sensitive information, such as that required to be protected pursuant to NERC Standard CIP 003, is lost or is removed without authorization.

        Report within: 48 hours of discovery of theft or loss.

    d. Unauthorized modification — Unauthorized addition or modification of software or data associated with the proper operation of cyber assets.

Report when: malicious software or data modification is discovered on a cyber asset or assets that may impact the reliability of the bulk power system.

Report within: 4 hours of detection.

2. Suspected Activities:
    a. Attempted Physical Intrusion — A detected effort to gain unauthorized access of a person or a device through the physical perimeter but without obvious success.

        Report when: attempt to gain unauthorized physical access to facilities, systems, or equipment (such as critical assets or critical cyber assets) that could impact the reliable operation of the bulk power system is targeted, focused, or repetitive.

        Report within: 1 hour of detection.

    b. Attempted Cyber Intrusion — A detected effort to gain unauthorized ingress or egress through the electronic perimeter or into an electronic perimeter device but without obvious success.

        Report when: attempt to gain unauthorized electronic access to cyber assets (such as critical cyber assets) whose impairment could impact bulk power system reliability is targeted, focused, or repetitive.

        Report within: 1 hour of detection.

3. Surveillance Activities – Intelligence Gathering:
    a. Social Engineering — The attempt by an unauthorized person to manipulate people into performing actions or divulging information.

        Report when: suspected or actual instances of social engineering occur.

        Report within: 8 hours of recognition.

    b. Photography — Taking still or moving pictures.

Report when: incident of photo taking is suspicious.

Report within: 8 hours.

c. Observation — Showing unusual interest in a facility; for example, observing it through binoculars, taking notes, drawing maps, or drawing structures of the facility.

Report when: activity is suspicious or unauthorized.

Report within: 8 hours.

d. Flyover — Flying an aircraft over a facility; this includes any type of flying vehicle including an unmanned aerial vehicle (UAV) loitering over a site.

Report when: activity is suspicious or unauthorized.

Report within: 8 hours.

4. Threats:
   a. Expressed Threat — Communicating a threat.

   Report when: threatened action has the potential to damage or compromise a facility or personnel.

   Report within: 1 hour of receipt of threat.

   b. Weapons Discovery — Discovery of explosives.

   Report when: explosives are discovered at or near a facility.

   Report within: 1 hour of detection.

   Attack (Physical or Cyber or Communication) — Attack via physical, cyber, or communications means.

   Report when: suspected or actual attacks against generation, transmission, or company-owned or operated communication facilities, cyber assets, or personnel occur.

   Report within: 1 hour of an actual attack.
   6 hours of a suspected attack.

Event category: EQUIPMENT AND /OR SYSTEMS FAILURE

1. Failure or Compromise of Computer Software or Hardware Used for Control, Monitoring or Alarming — Failure or malfunction of any critical reliability tool or system, or components thereof, such as EMS, SCADA, or other critical cyber assets as identified pursuant to NERC Standard CIP-002.

   Report when: the unplanned loss or malfunction may result in actual or potential risk to the bulk power system and lasts 30 minutes or longer.

   Report within: 1 hour of loss or malfunction.

2. Communication Systems Failure, Impairment, or Compromise — Failure, degradation of functionality, or unauthorized access or use of facilities used for the exchange of voice or data.

   Report when:
   - the incident disrupts the monitoring or operation of the bulk power system, or
   - the incident involves unauthorized access to or use of systems.

   Report within: 6 hours

Event category: OTHER

1. Fuel Supply Problems — Problem with the fuel supply to a generating unit or station. Problems may be due to transportation, supply, delivery, or quality of the fuel.

   Report when: fuel supply problems could impact electric power system reliability or adequacy; or, fuel inventories or hydro storage levels are 50% of normal or less.

   Report within: 6 hours of the recognition that a problem exists.

   Loss of Off-site Power at Nuclear Unit — Degradation of voltage below minimum requirements of the electric power supply provided from the transmission system to the nuclear power plant distribution system as required per the nuclear power plant license.

Report when: voltage degrades beyond required limits.

Report within: 1 hour.

Information to Report

The amount of information to report for each incident should include the following:

- reporting individual, entity name, and contact information for follow-up;
- date, time and location (NERC region, state/province, city) of the incident;
- brief description of incident, including affected transmission and generation facilities, load loss, generation loss, reactive and voltage impacts and approximate number of customers and their locations as appropriate;
- impact on critical infrastructure, public health and safety, environment;
- expected duration of impact, or time to restore;
- cause, if known; and
- law enforcement involvement.

To facilitate reporting, the ES-ISAC has developed an incident report form, which is available for download at www.esisac.com. This form has been incorporated into electronic reporting mechanisms noted below. For incidents that meet the OE-417 or EOP-004 reporting requirements, entities may submit those forms to the ES-ISAC.

Reporting Timeliness

Entities should develop processes to ensure timely reporting of incidents to the ES-ISAC. These processes also should address timely reporting to others with a need-to-know, including:

- law enforcement (e.g., local, state/provincial, FBI/RCMP);
- government agencies and regulators as is necessary or required (e.g., at the state/provincial or federal level);
- other electricity sector entities (e.g., balancing authorities, reliability coordinators, regional transmission operators, and independent system/market operators); and,
- critically interdependent customers or service providers.

Reporting should be based on the best available information, and promote the sharing of information on an actionable, need-to-know basis. Entities are encouraged to report incidents as soon as practical.

Some entities are required by law to report incidents within specified time frames (e.g., DOE's Form OE-417 Emergency Incident and Disturbance Report). It is incumbent upon all entities to understand their reporting obligations.

Reporting Mechanisms

The following list provides information about various tools that entities may opt to use to report events and incidents to the ES-ISAC and other information sharing partners. Entities may choose to use one or more tools depending on the incident to be reported.

1. Critical Infrastructure Protection Information System (CIPIS)
   Provides a secure Internet messaging system for communication with the ES-ISAC, DHS, Public Safety Canada, and electricity sector participants. Access to CIPIS is restricted to authorized electricity sector participants. Registration instructions are available at www.esisac.com.

2. Reliability Coordinator Information System (RCIS)
   NERC reliability coordinators have the option to use this secure messaging system for event and incident reporting. Use of RCIS is limited to reliability coordinators.

3. Telephone, fax, or email
   Phone: 609-452-1422 (24x7)
   Fax: 609-452-9550 (normal business hours)
   E-mail: esisac@nerc.com (anytime)

Information Dissemination and Confidentiality:

Upon approval of the submitting entity, incident reports received by the ES-ISAC may be transmitted to government agencies in the United States and Canada, to other electric sector participants, and to other critical infrastructure sectors on a confidential and need-to-know basis.

The ES-ISAC follows established procedures for protecting confidential information prior to sharing with others.

Incident reports containing confidential information shared voluntarily with

government agencies are protected from public disclosure per the following legislation and regulations.

- In the United States:
  - Critical Infrastructure Information Act of 2002 (CII Act)
  - DHS Protected Critical Infrastructure Information (PCII) regulations
  - FERC Critical Energy Infrastructure Information (CEII), Order No. 683, September 21, 2006
  - Freedom of Information Act exemption B4: Trade Secrets and Proprietary Information and Section 204 of the Homeland Security Act of 2002
- In Canada:
  - Sections 16(2)(c) and 20(1)(b) of the Access to Information Act
  - Emergency Management Act (bill C12)

Related Documents and Links:

1. NERC Reliability Standard CIP-001-1, Sabotage Reporting, January 1, 2007.
2. NERC Reliability Standard CIP-008-1, Incident Reporting and Response Planning, June 1, 2006.
3. NERC Reliability Standard EOP-004-1, Disturbance Reporting, January 1, 2007.
4. U.S. Department of Energy, Office of Energy Assurance, OE-417 — Electric Emergency Incident and Disturbance Report, April 2007.

Revision History:

Date	Version Number	Reason/Comments
7/29/08		Additional citation under the Information Dissemination and Confidentiality section.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Appendix A: Reporting Cross-Reference Matrix*

Category	Sub-category	Event Definition	Report When:	Report Within:	Cross-reference to Reporting Requirements
EMERGENCY ACTIONS					
	Public Appeals	An official utility, regulatory agency, or government request that the public reduce its consumption of electricity.	An appeal has been issued.	1 hour	OE-417 - Schedule 1, Item 8, Public Appeals
	Voltage Reduction	An entity intentionally lowers the voltage on its system in order to reduce demand.	Operator-initiated reduction of 3 percent or more is applied system wide.	1 hour	OE-417 - Schedule 1, Item 7, Voltage Reductions
	Firm Load Shedding	The intentional outage of customer load in significant quantities either through automatic or operator-initiated actions to protect the bulk power system.	Anticipated or actual disconnection of 100 MW or more occurs.	1 hour	OE-417 - Schedule 1, Item 6, Load Shedding
	Relocation of Control Center Operations	Transfer of operational control to an alternative site or a return of control to a primary control center.	The transfer of control, due to operational necessity rather than testing or training, has started.	2 hours	DHS ES-ISAC
SYSTEM DISTURBANCES					
	Loss of Firm Load	The unintentional outage of firm customer load, including distribution load.	300 MW or more is lost for more than 15 minutes from a single incident. More than 50,000 customers are affected for an hour or more.	1 hour 6 hours	OE-417 - Schedule 1, Item 5, Uncontrolled Loss of Firm System Load OE-417 - Schedule 1, Item 11, Loss of Electric Service

Appendix A: Reporting Cross-Reference Matrix*

Category	Sub-category	Event Definition	Report When:	Report Within:	Cross-reference to Reporting Requirements
	Forced Outage	A loss of or required removal from service availability of a generating unit, transmission line, or other equipment due to unanticipated reasons.	**Generation:** 500 MW or more is affected due to unknown causes. 2,000 MW or more is affected in the Eastern Interconnection or in WECC or 1,000 MW or more is affected in ERCOT regardless of the actual or suspected cause. **Transmission:** Loss of a facility that significantly affects the integrity of bulk power system operations. **Other:** Analysis of the outage leads to one or more of the following actions: a. modification of operating procedures. b. modification of equipment (e.g., control systems or special protection systems) to prevent reoccurrence of the event. c. identification of valuable lessons learned. d. identification of non-compliance with NERC standards or policies. e. identification of a disturbance that is beyond recognized criteria, i.e., three-phase fault with breaker failure, etc.	24 hours	ES-ISAC EOP-004, Attachment 1, Item 3 EOP-004, Attachment 1, Item 1 EOP-004, Attachment 1, Item 1
	Frequency Excursions	A significant change in the interconnection frequency that occurs suddenly or over a period of time.	Excursion is below underfrequency load shed point for firm loads.	24 hours	EOP-004, Attachment 1, Item 1f

Appendix A: Reporting Cross-Reference Matrix*

Category	Sub-category	Event Definition	Report When:	Report Within:	Cross-reference to Reporting Requirements
	Voltage Excursions/ Collapse	A significant change in the voltage that occurs suddenly or over a period of time.	Excursion is +/- 10% of nominal voltage or is below undervoltage load shed point.	24 hours	EOP-004, Attachment 1, Item 1f and Item 6
	Islanding or Separation	Part or parts of an interconnection remain(s) in operation following the separation of normally interconnected areas.	Islanding or separation occurs.	1 hour	OE-417, Item 4 and EOP-004, Attachment 1, Item 2
	Complete System Failure (Blackout)	Complete operational failure or shutdown of an entity's transmission or distribution electrical system or both.	A complete operational failure or shutdown of transmission or distribution electrical system or both occurs.	1 hour	OE-417 - Schedule 1, Item 3
SABOTAGE/TAMPERING/VANDALISM (STV) – Physical or Cyber					
	Security Breaches:				
	Physical Perimeter Compromise	Unauthorized access of a person or a device through, circumventing, or damaging the physical perimeter, or security systems protecting the physical perimeter.	Unauthorized physical access to facilities, systems, or equipment (such as critical assets or critical cyber assets) that could impact the reliable operation of the bulk electric system; or, intentional damage to security systems that protect the physical perimeter.	1 hour of detection	OE-417 - Schedule 1, Item 1
	Cyber Perimeter Compromise	Unauthorized ingress or egress through the electronic perimeter or into an electronic perimeter device.	Unauthorized electronic access to cyber assets whose impairment could impact the reliability of the bulk power system is unauthorized.	1 hour of detection	OE-417, Schedule 1, Item 2

Appendix A: Reporting Cross-Reference Matrix*

Category	Sub-category	Event Definition	Report When:	Report Within:	Cross-reference to Reporting Requirements
	Information Theft or Loss	Unauthorized removal or loss of sensitive information.	Sensitive information, such as that required to be protected pursuant to NERC Standard CIP-003 is lost or is removed without authorization.	48 hours of detection	ES-ISAC
	Unauthorized Modification	Unauthorized addition or modification of software or data associated with the proper operation of cyber assets.	Malicious software or data modification is discovered on a cyber asset or assets that may impact the reliability of the bulk power system.	4 hours of detection	DHS ES-ISAC
	Suspected Activities:				
	Attempted Physical Intrusion	A detected effort to gain unauthorized access of a person or a device through the physical perimeter but without obvious success.	Attempt to gain unauthorized physical access to facilities, systems, or equipment (such as critical assets or critical cyber assets) that could impact the reliable operation of the bulk power system is targeted, focused, or repetitive.	6 hours upon detection	OE-417, Schedule 1, Item 9
	Attempted Cyber Intrusion	A detected effort to gain unauthorized ingress or egress through the electronic perimeter or into an electronic perimeter device but without obvious success.	Attempt to gain unauthorized electronic access to cyber assets (such as critical cyber assets) whose impairment could impact bulk power system reliability is targeted, focused, or repetitive.	6 hours upon detection	OE-417, Schedule 1, Item 10
	Surveillance Activities – Intelligence Gathering:				
	Social Engineering	The attempt by an unauthorized person to manipulate people into performing actions or divulging information.	Suspected or actual instance occurs.	8 hours of recognition	DHS ES-ISAC
	Photography	Taking still or moving pictures.	A suspicious incident occurs.	8 hours	DHS ES-ISAC
	Observation	Showing unusual interest in a facility; for example, observing it through binoculars, taking notes, drawing maps, or drawing structures of the facility.	Activity is suspicious or unauthorized.	8 hours	DHS ES-ISAC

Appendix A: Reporting Cross-Reference Matrix*

Category	Sub-category	Event Definition	Report When:	Report Within:	Cross-reference to Reporting Requirements
	Flyover	Flying an aircraft over a facility; this includes any type of flying vehicle including an unmanned aerial vehicle (UAV) loitering over a site.	A suspicious or unauthorized incident occurs.	8 hours	DHS ES-ISAC
	Threats:				
	Expressed Threat	Communicating a threat.	Threatened action has the potential to damage or compromise a facility or personnel.	1 hour	DHS ES-ISAC
	Weapons Discovery	Discovery of explosives.	Discovery occurs at or near a facility.	1 hour	ES-ISAC
	Attacks:				
	Actual Attack (Physical or Cyber or Communication)	Attack via physical, cyber, or communications means.	An actual attack against generation, transmission, or company-owned or operated communication facilities, cyber assets, or personnel occurs.	1 hour	OE-417 - Schedule 1, Items 1 and 2
	Attempted Attack (Physical or Cyber or Communication)	Attack via physical, cyber, or communications means.	A suspected attack against generation, transmission, or company-owned or operated communication facilities, cyber assets, or personnel occurs.	6 hours	OE-417 - Schedule 1, Items 9 and 10

Appendix A: Reporting Cross-Reference Matrix*

Category	Sub-category	Event Definition	Report When:	Report Within:	Cross-reference to Reporting Requirements
EQUIPMENT AND/OR SYSTEMS FAILURE					
	Failure or Compromise of Computer Software or Hardware Used for Control, Monitoring or Alarming.	Failure or malfunction of any critical reliability tool or system, or components thereof, such as EMS, SCADA, or other critical cyber asset as identified persuant to NERC Standard CIP-002.	Unplanned loss or malfunction lasting 30 minutes or longer that may result in actual or potential risk to the bulk power system.	1 hour	ES ISAC
	Communication Systems Failure, Impairment, or Compromise	Failure, degradation of functionality, or unauthorized access or use of facilities used for the exchange of voice or data.	Disrupts the monitoring or operations of bulk power system. Unauthorized access to or use of systems whether or not the bulk power system is affected.	6 hours	OE-417 - Schedule 1, Item 10
OTHER					
	Fuel Supply Problems	Problem with the fuel supply to a generating unit or station. Problems may be due to transportation, supply, delivery, or quality of the fuel.	Fuel supply problem could impact electric power system reliability or adequacy or fuel inventories or hydro storage levels are 50% of normal or less.	6 hours of the recognition of a problem	OE-417 - Schedule 1, Item 12
	Loss of Off-site Power at Nuclear Unit	Degradation of voltage below minumum requirements of the electric power supply provided from the transmission system to the nuclear power plant distribution system as required per the nuclear power plant license.	Voltage degrades beyond required limits.	1 hour	ES-ISAC

Appendix A: Reporting Cross-Reference Matrix*					
Category	**Sub-category**	**Event Definition**	**Report When:**	**Report Within:**	**Cross-reference to Reporting Requirements**

**** This cross-reference is provided for convenience. It is not intended to be inclusive. Entities must understand and meet their required reporting obligations.***

Reporting Mechanisms:

The following list provides information about various tools that entities may opt to use to report events and incidents to the ES-ISAC and other information sharing partners. Entities may choose to use one or more tools depending on the incident to be reported.

1. Critical Infrastructure Protection Information System (CIPIS)

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3. Telephone, fax or email

Phone: 609-452-1422 (24x7)
Fax: 609-452-9550 (business hours)
Email: esisac@nerc.com (anytime)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Draft Meeting Minutes
Planning Committee

September 10, 2008 | 1–5 p.m.
September 11, 2008 | 8–12 p.m.
Doubletree Hotel Seattle Airport
Seattle, WA 98188

Planning Committee (PC) Chair Scott M. Helyer presided over this meeting of the NERC PC. The meeting notice, agenda, and list of attendees are attached as Exhibits A, B, and C respectively. Meeting materials and presentations may be found in separate files at http://www.nerc.com/~filez/pcmin.html.

Administrative Matters

Quorum: Of the PC's 28 total voting member positions, the PC has three vacancies: merchant electricity generator (1), and large end-use customer (2), leaving 25 voting members.[1] The meeting quorum (⅔ of 25, or 17, rounded up) was exceeded by the 20 members or their proxies who attended. The following proxies attended the meeting for absent PC voting members: Gene Ng for Naren Pattani (federal/provincial), Larry Reiter for Charles Jenkins (RRO-ERCOT), Phil Fedora for Henry Masti (NPCC), and Charles Yeung for Jim Useldinger (RRO-SPP). Kris Zadlo (merchant electricity generator), Glen Smith (electricity marketer), Glenn Ross (small end-use customer), Mary Healey (small end-use customer), and Erik Saltmarsh (state government) did not attend the meeting or send a proxy.

Antitrust Compliance Guidelines: John Seelke reviewed the NERC Antitrust Compliance Guidelines.

Approval of Agenda:
The PC approved the agenda for the September 10–11, 2008 PC Meeting. The committee also granted Chair Helyer the flexibility to reorder agenda items if he felt it appropriate. Chair Helyer noted that the PC organization would be discussed after the PC Charter was discussed.

Approval of June 4–5, 2008 PC Meeting Minutes: The PC approved the minutes of the June 4–5, 2008 PC Meeting. The minutes appear at: http://www.nerc.com/filez/pcmin.html.

[1] The RRO sector has two votes for its eight-member sector.

Highlights of the July 29, 2008 Member Representatives Committee (MRC) and July 30, 2008 Board of Trustees (BOT) Meeting: Chair Helyer stated critical infrastructure protection issues, especially cyber security, were receiving more attention. He also noted that the Readiness Evaluation program was being phased out in 2009.

PC Subgroup Meetings in 2009: As described in the agenda material, subgroup meetings will be conducted at the offices of a subgroup member. This requirement applies to all subgroup meetings not yet scheduled. While the subgroup member hosting the meeting is encouraged to absorb the costs of lunch and break refreshments since that member did not incur any travel costs, the host may request a contribution from each attendee. Several PC members suggested that exceptions to meeting at a subgroup member's location should require the approval of the PC Chair, and although a vote was not taken, this appeared to be a consensus. It was noted that some valid exceptions would be (i) when a subgroup meeting is held in conjunction with a PC meeting, which saves travel costs for subgroup members also attending the PC meeting, or (ii) when NERC has already entered into a contract with the hotel to provide meeting space and the contract has some significant monetary cancellation provisions.

Functional Model – version 4: On a motion by Bob Williams, the committee approved version 4 with respect to the planning functions, with comments to be separately provided by PC members to the PC Secretary who will forward them to the Standards Committee for their consideration. After the meeting, the PC Secretary requested comments be submitted by Sept. 18. Three members provide comments which are complied in Exhibit D.

PC Charter: Secretary Seelke explained the proposed charter revisions and answered questions about them. On motion by Jean-Marie Gagnon, the committee approved the charter revisions. The revised charter will be submitted to the Board of Trustees for consideration at their October 29, 2008 meeting.

PC Organization: Vice Chair Burgess will be heading a team to examine the PC organization. This team will review the appropriateness of the scopes of the committee's subgroups (shown on the organization chart which is included in the agenda material). Jean-Marie Gagnon and Stuart Nelson volunteered to serve on the team.

Integration of Variable Generation Task Force

The PC members provided the following feedback for IVGTF Chair Warren Frost regarding the draft conclusions:

- It would be helpful if the final report could identify (i) practices and methods currently in use that address some of the issues, and (ii) which issues could be followed up by the IVGTF and which issues need to be assigned to another subgroup.
- The Bonneville Power Administration would not support the effective load carrying capability approach in computing the capacity value of wind because

the Northwest evaluates the contribution of wind toward capacity adequacy when it is needed most, i.e. during a heat wave or cold snap event. Capacity is currently not an issue during other times because of the hydro-dominated nature of the resource mix.[2]

Reliability Assessment

Reliability Assessment Improvement Task Force: RAITF Chair Gary Brinkworth gave the RAITF's report and the PC approved these three motions:

- A motion by Tim Ponseti to approve the proposed capacity definitions for use in the 2009 reliability assessment reporting cycle after the correction of a typo on footnote 7 on page 3 (replace "I.B" with "II.B").
- A motion by the Tim Ponseti to accept the RAITF's final report with these corrections: (i) P. 3, last paragraph: change "reviewed" to "endorsed"; (ii) P. 4, Figure 1: the schedule of activities shown above the time line apply to the LTRA and not to the summer or winter assessments, and that needs to be clarified; (iii) P. 29, footnote 21: replace "I.B" with "II.B."
- A motion by Bob Williams to disband the RAITF. Chair Helyer and Vice Chair Burgess expressed their thanks on behalf of the entire PC to the RAITF for its work.

Reliability Assessment Subcommittee Report: RAS Vice Chair Mark Kuras provided the RAS report, and Mark Lauby gave an overview of the current draft of the Long–Term Reliability Assessment (LTRA). For the LTRA, there was discussion on the Emerging Issues slide.

- Peter Wong felt that the term "emerging issues" had a negative connotation and that consideration should be given to renaming this topic.
- Questions clarified that the first point used to develop the "arrows" on the emerging issues slide represented the likelihood and consequences for years 1–5, while the second point represented the likelihood and consequences for years 6–10.

A draft embargoed (not for distribution) 2008 LTRA will be posted on September 16, 2008 for PC members to assess in preparation for a September 25, 2008 WebEx and conference call scheduled from 11 a.m.– 12:30 p.m. Eastern time to consider the 2008 LTRA.

Reliability Metrics Working Group: RMWG Chair Jason Shaver provided the RMWG's report. The RMWG is working on additional LTRA metrics to supplement the capacity margin metric currently used. The RMWG does not have adequate planning expertise, and PC Chair Helyer asked for volunteers to join the RMWG. Ed Pfeiffer and John Simpson volunteered to work on the RMWG and Ben Crisp committed to providing a person from either Progress Energy or FRCC.

[2] Comment provided by Mary Johannis of BPA.

Reliability Assessment Guidebook Task Force: RAGTF Chair Tom Burgess provided the report. The guidebook is a "work in progress," and he requested feedback from the regions regarding the content and usefulness since the guidebook is intended to help the regions. One of the concerns raised was that the guidebook needs include some direction for completing the assessment data requests in addition to just providing a description of the data and process. Burgess asked for volunteers from ERCOT, SERC, MRO, and FRCC to join the RAGTF. Ed Weber and Bob Williams volunteered to work on the RAGTF and Ben Crisp committed to providing a person from either Progress Energy or FRCC.

Resource Issues

Resource Issues Subcommittee Report: RIS Chair Mary Johannis provided a presentation on the activities of the RIS, and John Moura summarized the activities of the Demand Response Data Task Force.

Transmission Issues

Transmission Availability Data System Task Force Report: Jean-Marie Gagnon gave a presentation on the TADS Phase II approach to collect Non-Automatic Outages. Various concerns were raised and discussed about the need for Phase II and the timing for proceeding with Phase II. On a motion by Jeff Mitchell, the committee approved the TADS Phase II report. The next step will be to present the Phase II report to the Board of Trustees for their consideration at their upcoming October 29, 2008 meeting.

Transmission Issues Subcommittee Report: TIS Chair David Till provided an update at the TIS's activities, which included a report on Fault Induced Delayed Voltage Recovery (FIDVR). On a motion by John Simpson, the committee approved two tasks: (i) the TIS is to present an updated FIDVR report to the committee at its December 2008 meeting that would include a proposed definition of FIDVR, and (ii) the TIS and the SPCTF are to coordinate and develop guidelines for considering protection and control actions and potential misoperations in FIDVR studies.

New Draft of TPL-001: Chair Helyer encouraged individual PC members to provide comments on the new draft standard by the due date of September 29, 2008. The August 14, 2008 e-mail that announced the comment period and provided instructions for providing comments is included in the agenda material.

System Protection and Control Task Force: SPCTF Chair John Ciufo reviewed the activities of the SPCTF.

Next Committee Meeting

The next meeting will be held on December 3–4 in Orlando, Florida. The details are posted on the NERC Web site

Respectfully submitted,

John Seelke

John Seelke, PC Secretary

From: Rocio Wong

Exhibit A

To:
CC:
Subject: REVISED MEETING: NERC September 2008 Standing Committee Meetings
Date: Tuesday, July 22, 2008 3:37:41 PM
Attachments: image001.gif

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standing Committee Meetings

September 9-12, 2008 | Seattle, WA

CORRECTED DATES IN TABLE BELOW

Doubletree Hotel Seattle Airport
18740 International Boulevard
Seattle, WA 98188 (Map)
(206) 246-8600
Please call the hotel directly to book reservations

$179 night group rate | Code: NERC
Hotel cut-off date: August 19, 2008 (Rooms booked after this date will be subject to full price, if available)
Room block available from: 9/9 – 9/11 (limited guest rooms available)
Check in: 3 PM – Check out: 12 PM
Dress Code: Business Casual

Group Name	Registration Link	Tuesday, September 9	Wednesday, September 10	Thursday, September 11	Friday, September 12
REMG & Committee Officers	Not required		7 – 9 AM		
Operating Committee	Joint OC	Exec Committee: 4:30 – 7 PM	Joint: 9 AM – 12 PM OC: 1 – 5 PM	8 AM – 12 PM	
Planning Committee	Joint PC	Exec Committee: 4:30 – 7 PM	Joint: 9 AM – 12 PM PC: 1 – 5 PM	8 AM – 12 PM	
Critical Infrastructure Protection Committee	Joint CIPC		Joint: 9 AM – 12 PM	8 AM – 5 PM	8 AM – 12 PM

Schedule includes other associated NERC meetings.

View/print announcement in .pdf format

Rocio Wong
Meeting Planner
North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com
rocio.wong@nerc.net

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit B

Agenda
Planning Committee

September 10, 2008 | 1–5 p.m.
September 11, 2008 | 8–12 p.m.

Doubletree Hotel Seattle Airport
18740 International Boulevard
Seattle, WA 98188
(206) 246-8600

Item	Leader	Action
1. Administrative Matters		
a. Welcome and Introductions	Scott Helyer	
b. Quorum	John Seelke	
c. Antitrust Guidelines	John Seelke	
d. Arrangements	John Seelke	
e. PC Agenda	Scott Helyer	Approve agenda
f. Minutes of June 4-5, 2008 PC Meeting	Scott Helyer	Approve minutes
g. Highlights of July 29 Member Representatives Committee and July 30, 2008 Board meetings	Scott Helyer	Information
h. PC Subgroup Meetings in 2009	Scott Helyer	Information
i. PC Chair Remarks	Scott Helyer	
j. Functional Model – version 4	Stephen Crutchfield	Approve version 4 with respect to the planning functions
k. PC Charter	John Seelke	Approve PC Charter changes
2. Integration of Variable Generation Task Force Report	Warren Frost	Discussion

Item	Leader	Action
3. Reliability Assessment		
a. Reliability Assessment Improvement Task Force Report	Gary Brinkworth	i. Approve capacity definitions for 2009 LTRA ii. Accept the RAITF final report iii. Disband the RAITF
b. Reliability Assessment Subcommittee Report	Bill Bojorquez	Discuss the 2008 LTRA
c. Reliability Metrics Working Group Report	Jason Shaver	Discuss recommended future LTRA metrics
d. Reliability Assessment Guidebook Task Force Report	Tom Burgess	Discussion
4. Resource Issues Subcommittee Report (includes the report of the Demand Response Data Task Force)	Mary Johannis	Discussion
5. Transmission Issues		
a. Transmission Availability Data System Task Force Report	Jean-Marie Gagnon	Approve Phase II TADS final report
b. Transmission Issues Subcommittee Report	David Till	Approve FIDVR White Paper
c. New draft of TPL-001	Scott Helyer	Discussion on providing committee or subgroup comments
d. System Protection and Control Task Force Report	John Ciufo	Discussion
6. Next Meeting	John Seelke	Information

EXHIBIT C

ATTENDEES
Planning Committee Meeting
September 10-11, 2008

OFFICERS

Chairman	Scott M. Helyer
Vice Chairman	Thomas C. Burgess
Secretary	John L. Seelke

MEMBERS

VOTING MEMBERS

Investor-owned utility	Richard J. Kafka
Investor-owned utility	Perry Stowe
State/municipal utility	Stuart Nelson
State/municipal utility	Ralph Rufrano
Cooperative utility	Jay Farrington
Cooperative utility	Ronnie Frizzell
Federal/provincial utility	Jean-Marie Gagnon
Federal/provincial utility	R.W. Mazur
Federal/provincial utility	Gene Ng (P)
Federal/Provincial utility	Tim Ponseti
Trans. dependent utility	Denise Roeder
Trans. dependent utility	Robert Williams
Merchant elec. generator	
Merchant elec. generator	To be named
Electricity marketer	Israel Melendez
Electricity marketer	
Large end-use customer	To be named
Large end-use customer	To be named
Small end-use customer	
Small end-use customer	
ISO/RTO	Mark Westendorf
ISO/RTO	Peter Wong
RRO/ERCOT	Larry Reiter (P)
RRO/FRCC	Ben Crisp
RRO-MRO	Edward P. Weber
RRO-NPCC	Phil Fedora (P)
RRO-RFC	Jeffrey L. Mitchell
RRO-SERC	Ed Pfeiffer
RRO-SPP	Charles Yeung (P)
RRO-WECC	John L. Simpson
State government	Phil Riley
State government	

(P) = proxy

NONVOTING MEMBERS

U.S. Federal	David Andrejcak
U.S. Federal	To be named
Canadian Federal	To be named
Provincial	

ATTENDEES — Planning Committee Meeting (cont.)
September 10-11, 2008

REGIONAL MANAGERS
None

NERC STAFF
Mark Lauby
John Moura
Jim Robinson
Ron Niebo
G. Michael Curley

PC SUBGROUP CHAIRS[1]

Mary Johannis	Chair, Resource Issues Subcommittee
John Ciufo	Chair, System Protection and Control Task Force
Jason Shaver	Chair, Reliability Metrics Working Group
David Till	Chair, Transmission Issues Subcommittee
Gary Brinkworth	Chair, Reliability Assessment Improvement Task Force

GUESTS

Mark Kuras	Vice Chair, Reliability Assessment Subcommittee
Paul McCurley	NRECA
Charles Rogers	Consumers Energy
John Odom	FRCC
Joe Spencer	SERC
Ray Kershaw	ITC Holdings
Paul Roehr	American Transmission Co.
John Seidel	MRO
Matt Holtz	NIPSCO
Nathan Mitchell	APPA
Jim Cyrulewski	Chair, Functional Model Working Group
Guy Zito	NPCC
John Babik	Dominion

1 Excludes subgroup chairs that are committee members.

Exhibit D

Planning Committee Member Comments re: Functional Model – version 4

- **Mark Westendorf** (received on 9/15/08)

John,

Functional Model Version 4 was approved at the NERC PC meeting last week. It was understood in the presentation and Q and A that the FMWG would be reviewing the Planning functions and roles of the Planning Coordinator, Transmission Planner and Resource Planner for version 5. Additionally, even though version 4 was approved, NERC has to do more work in defining the Interchange Authority and corresponding functions. The NERC Interchange Subcommittee has submitted a Standard Authorization Request to fix the problems with the Interchange Authority standards.

Thanks,
Mark Westendorf
Technical Manager
Midwest ISO
317-249-5970

- **Peter Wong** (received on 9/16/08)

Good Morning John,

Attached are comments develop by our Demand Resource (DR) staff, Bob Laurita, concerning the draft Functional Model version 4. We suggest adding DR Functions and DR Entities to the Functional Model. In addition, we are proposing some language changes to the existing document. ***[Note: Mr. Laurita's comments are attached.]***

Please note that in the "Introduction" section on page 6, there is an extra close " after the word Responsible at the end of the second line in the large paragraph above "Functional Model Maintenance".

Please forward these comments to the Standards Committee and thank you for the opportunity to comment.

Peter

- **Philip Riley** (received on 9/16/08)

Hi, John!

It was good to see you in Seattle. Home your trip home was good!

As for the Functional Model...I don't have any substantive comments. I would recommend a knowledgeable, thorough proofreader go over the draft with the proverbial fine-tooth comb before sending it upward. I noted a lot of typos, grammatical and punctuation errors.

Have a great one!

Phil

Comments provided by Mr. Bob Laurita:

Function – Demand Resource Operations

Definition

Operate demand resource(s) to provide reductions in load.

Tasks

1. Formulate daily demand resource plan.

2. Report operating and availability status of demand resources.

3. Develop annual maintenance plan for demand resources and perform the day-to-day maintenance.

4. Operate demand resources generators to provide load reductions per contracts or arrangements.

5. Monitor the status of facilities classed as demand resources.

Responsible Entity – Demand Resource Operator

Introduction to the Demand Resource Operator

The Demand Resource Operator is responsible for the implementation, operation and maintenance of demand resources under its purview within a Balancing Authority Area. The Demand Resource Operator has the authority to take certain actions to ensure that its demand resources operate reliably.

Relationships with Other Responsible Entities

Ahead of Time

1. Provides demand resource commitment plans to the Balancing Authority.

2. Provides Balancing Authority and Transmission Operators with requested amount of reliability-related demand resources.

3. Provides operating and availability status of demand resources to Balancing Authority and Transmission Operators for reliability analysis.

4. Reports annual maintenance plan for demand resources to Reliability Coordinator, Balancing Authority and Transmission Operators.

6. Provides operational data to Reliability Coordinator.

7. Revises demand resource maintenance plans per directive of Reliability Coordinator.

8. Receives reliability analyses from Reliability Coordinator.

10. Receives reliability alerts from Reliability Coordinator.

Real Time

11. Provides real-time operating information on demand resources to the Transmission Operators and the required Balancing Authority.

12. Adjusts load reductions as directed by the Balancing Authority and Transmission Operators.

Function – Demand Resource Ownership

Definition

Owns and provides for maintenance of demand resources.

Tasks

1. Establish demand resource load reduction ratings, limits, and operating requirements.

2. Authorize maintenance of owned facilities classified as demand resources.

3. Provide verified performance characteristics / data on demand resources.

Responsible Entity – Demand Resource Owner

Introduction to the Demand Resource Owner

Owns and provides for maintenance of demand resources.

Relationship with Other Responsible Entities

1. Coordinates with Transmission Planners and the Planning Coordinator, Distribution Providers, Load-Serving Entities, Balancing Authority, to implement demand resources with the bulk power system.
2. Develops agreements or procedures with the Balancing Authority.
3. Develops operating agreements or procedures with the Balancing Authority, Reliability Coordinators and Distribution Providers.
4. Provides demand resource expansion plans and changes to the Planning Coordinator and Balancing Authority.
5. Provides demand resource ratings and performance characteristics to Transmission Operators, Reliability Coordinators, Transmission Service Providers, Distribution Providers, Transmission Planners, and Planning Coordinator.
6. Provides demand resource construction plans and schedules to the Balancing Authority.
7. Provides demand resource maintenance plans and schedules to the Balancing Authority.
8. If appropriate for the demand resource, develops interconnection agreements with the Distribution Providers for connecting to the bulk power system.

Changes to Sections for Planning Coordinator, Transmission Planner, Resource Planner

Relationships with Other Responsible Entities:

Collects information including:

a. Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.

b. Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners.

c. Generator unit performance characteristics and capabilities from Generator Owners.

d. Demand Resource performance characteristics and capabilities from Demand Resource Owners, Load-Serving Entities, and Distribution Providers.

d. Long-term capacity purchases and sales from Transmission Service Providers.

Changes to Sections for Balancing Authority

Tasks

1. Control any of the following combinations within a reliability area:

    a. Load and generation (an isolated system)

    b. Load and scheduled Interchange

    c. Generation and scheduled Interchange

    d. Generation, load, and scheduled Interchange

2. Calculate area control error within the reliability area.

3. Operate in the reliability area to maintain load-interchange-generation balance.

4. Review generation and demand resource commitments, dispatch, and load forecasts.

5. Formulate an operational plan (generation and demand resource commitment, outages, etc.) for reliability evaluation.

6. Approve, Interchange Transactions from ramping ability perspective

7. Implement Interchange schedules by incorporating those schedules into its ACE calculation.

8. Operate the reliability area to support Interconnection frequency.

9. Monitor and report control performance and disturbance recovery.

10. Provide balancing and energy accounting (including hourly checkout of Interchange schedules and actual interchange), and administer inadvertent energy paybacks.

11. Determine needs for reliability-related services.

12. Deploy reliability-related services.

13. Implement emergency procedures.

Relationships with Other Responsible Entities:

Ahead of Time

1. Receives operating and availability status of generating and demand resource units and operational plans and commitments from Generator Operators, Demand Resource Operators, Load-Serving Entities, and Distribution Providers. (including annual maintenance plans) within the Balancing Authority Area.

2. Receives reliability evaluations from the Reliability Coordinator.

3. Receives approved valid, and balanced Interchange Schedules from the Interchange Authorities.

4. Compiles load forecasts from Load-Serving Entities.

5. Develops agreements with adjacent Balancing Authorities for ACE calculation parameters.

6. Submits integrated operational plans to the Reliability Coordinator for reliability evaluation and provides balancing information to the Reliability Coordinator for monitoring.

7. Confirms Interchange Schedules with Interchange Authorities.

8. Confirms ramping capability with Interchange Authorities.

9. Implements generator and demand resource commitment and dispatch schedules from the Load-Serving Entities, Demand Resource Operators, Distribution Providers and Generator Operators who have arranged for generation within the Balancing Authority Area.

10. Acquires reliability-related services from Generator Operator and Demand Resource Operator.

11. Receives dispatch adjustments from Reliability Coordinators to prevent exceeding limits.

12. Receives generator information from Generator Owners including unit maintenance schedules and retirement plans.

13. Receives demand resource information from Demand Resource Owners, Load Serving Entities and Distribution Providers including resource maintenance schedules and retirement plans.

13. Receives information from Load Serving Entities on self-provided reliability-related services.

14. Coordinates system restoration plans with Transmission Operator.

15. Provides generation and demand resource dispatch to Reliability Coordinators.

16. Receives final approval or denial of Interchange Schedules from Interchange Authority.

Real Time

17. Coordinates use of controllable loads with Demand Resource Operators, Distribution Providers and Load-Serving Entities (i.e., interruptible load that has been bid in as a reliability-related service or has agreed to participate in voluntary load shedding program under resource/reserve deficiency situations).

18. Receives loss allocation from Transmission Service Providers (for repayment with in-kind losses).

19. Receives real-time operating information from the Transmission Operator, adjacent Balancing Authorities, ~~and~~ Generator Operators and Demand Resource Operators.

20. Receives operating information from Generator Operators and Demand Resource Operators.

Agenda 14.g.
NERC Reports
Reliability Assessment Subcommittee

To: MRO Reliability Assessment Committee

From: Hoa Nguyen

Re: NERC Reliability Assessment Subcommittee (RAS) Meeting on 14-15 October 2008 in Portland, Oregon

Summary of Actions Taken by the NERC RAS

As part of the RAS meeting, I attended the second half of the Technical Summit on Reliability Impacts of Extreme Weather & Climate Change in the morning of 14 October 2008, which was optional for RAS members. Sponsored by NERC, EPRI, and PSERC, this technical summit was held at the Portland Marriot Downtown Waterfront. The presentations I attended were much more on the climate change topics than on their impacts on reliability. There were no conclusions or recommended actions to take as the results of the summit.

The RAS meeting was held at the Bonneville Power Administration office in Portland, Oregon. The security system in this federal facility was extremely tight; it caused a lot of delay in check-ins and a lot of personal discomfort throughout the meeting. The main objective of the meeting was to complete the preparation of the *NERC 2008-2009 Winter Assessment* targeted to be released 11 November 2008. During one and one-half days of meeting, the RAS:

- Peer-reviewed the regional self assessments for all regions, except WECC which submitted its assessment too late for the reviewers to study and make comments. The peer review of the WECC assessment would be done via e-mails by Wednesday 22 October.
- Discussed the time line for the *2008-2009 Winter Assessment* completion.
- Discussed the use of reserve margins vs. capacity margins, which are being exclusively by NERC, while the former are being used widely by the utility industry.
- Discussed feedback from the NERC Planning Committee regarding:
    - Instructions on the PC subgroups' meeting locations and logistics,
    - Reliability Assessment Improvement Task Force,
    - Integration of Variable Generation Task Force,
    - Demand Response Data Task Force,
    - Reliability Assessment Guidebook Task Force, and
    - The update of the LTRA emerging issues.
- Discuss the timelines for the completion of the *2009 Long Term Reliability Assessment* and the *2009 Summer Assessment*.
- Revised the RAS meeting schedule in 2009 and added another meeting in August 2009 for a total of six meetings. The new schedule is attached to this report.

Summary of Direction Given by the MRO RAC

N/A

Next Steps

- As the result of the RAS peer review, John Seidel and I rewrote the MRO 2008-2009 Winter Assessment to address the comments received during the meeting. The final draft that was submitted to the RAS on 22 October 2008 is included with this report. To address the question from a reviewer on the unusually high peak demand increase (4.3%) from last winter, we examined the peak demand data submitted by MRO members and discovered an error in one of the members' data submittal. When the peak demand is corrected, the increase becomes 1.9% and the MRO projected reserve margin increases from 32.1% (old write-up) to 35.2%.
- A phone conference of the RAS subgroup that is assigned with the task of reviewing the request letters for the RAS assessments and of which I am a member, is scheduled for 7 November 2008. The subgroup will review the request letters for the *2009 Long Term Reliability Assessment* and the *2009 Summer Assessment*.
- The next RAS meeting will be held 4-5 February 2009 in Atlanta, Georgia. Probably hosted by Georgia Power, it will be a two-full day meeting at which the RAS will make plans for the 2009 assessments and flesh out 2009 LTRA emerging issues.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

RAS Meeting Schedule 2009
Revised October 2008

Meeting	Purpose	Tentative Locations
January	No Meeting	
February 4-5 Day 1: 8:00 am to 5:00 pm Day 2: 8:00 am to 5:00 pm	• Review first draft of 2009 LTRA Scenario Plan • Review 2009 LTRA outline, possible regional issues to highlight – make assignments • Review feedback from the implementation of revised capacity definitions	Atlanta, GA. (NERC Board meets 2/11-12 in Phoenix) No internet access?
March	No Meeting	
April 8-9 8:00 am to 5:00 pm 8:00 am to 5:00 pm	LTRA • Complete LTRA Scenario Section Summer Assessment • **Finalize 2009 Summer Assessment** Special Topic Presentation (TBD)	Tampa, FLA
May	No Meeting ➢ **Publish Summer Assessment**	
June 23-24 8:00 am to 5:00 pm 8:00 am to Noon	LTRA • Finalize Data Section • Peer review of Regional Sections	Toronto, Ont. No internet access?
July 22-23 8:00 am to 5:00 pm 8:00 am to 5:00 pm	LTRA • Complete Peer review of Regional Section • Review Analysis Sec. • Review Summary Sec. • **Final 2009 LTRA draft** • Scope 2009/10 Winter Assessment Special Topic Presentation (TBD)	St. Paul, MN Transportation issue?
August 25-26	Meeting TBA	Charlotte – Herb Boston - Peter Philadelphia – Mark K.
September	No Meeting	
Oct 14-15 8:00 am to 5:00 pm 8:00 am to Noon	**Publish LTRA** Winter • **Finalize 2009/20010 Winter Assessment** LTRA • Review 2009 LTRA feedback and recommendations for 2010	Salt Lake City, Utah
November	No Meeting ➢ **Publish Winter Assessment**	

Dec 5 (Webex??) 8:00 am to 5:00 pm 8:00 am to noon	• Flesh out 2009 Issues • Review regional scenario development plans • LTRA Data Request Letter	

MRO 2008-2009 Winter Assessment

Summary

The Midwest Reliability Organization (MRO) is expected to have sufficient generating capacity within the region to maintain an adequate reserve margin for the 2008-2009 Winter peak demand. The transmission system within the MRO region is expected to perform reliably to meet firm customer demand for the 2008-2009 Winter. There are no significant operational issues that may cause reliability concerns expected in the MRO region during the upcoming winter.

MRO 2008-2009 Winter Assessment

Projected Total Internal Demand	43,080	MW
Interruptible Demand & DSM	1,541	MW
Projected Net Internal Demand	41,539	MW
Last Winter's Peak Demand	41,450	MW
All-Time Winter Peak Demand	41,450	MW
Deliverable Internal Capacity	56,349	MW
Firm Purchases	776	MW
Firm Sales	960	MW
Net Capacity Resources	56,165	MW
Capacity Margin	26.0	%
Reserve Margin	35.2	%
With Uncertain Resources		
Total Potential Resources	61,539	MW
Capacity Margin	26.8	%
Reserve Margin	36.6	%

Introduction

The Midwest Reliability Organization (MRO) is expected to have sufficient generating capacity within the region to maintain an adequate reserve margin for the 2008-2009 Winter peak demand. The transmission system within the MRO region is expected to perform reliably to meet firm customer demand for the 2008-2009 Winter. There are no significant operational issues that may cause reliability concerns expected in the MRO region during the upcoming winter.

The MRO is a Cross-Border Regional Entity representing the upper Midwest of the United States and Canada. MRO is organized consistent with the Energy Policy Act of 2005 and the bilateral principles between the United States and Canada. The MRO membership consists of the former and existing members of the MAPP Generation Reserve Sharing Pool (GRSP), members from

the former Mid-America Interconnected Network, Inc. (MAIN),[1] and Saskatchewan Power Corporation (SaskPower), one of the two Canadian members.[2] The transmission assessment and operational issues in this MRO regional self-assessment are, however, presented by geographical areas in the MRO footprint: Iowa, Nebraska, Northern MRO, Saskatchewan, and Wisconsin-Upper Michigan Systems (WUMS). The Northern MRO area consists of the Dakotas, Minnesota, part of Montana, and the Canadian province of Manitoba.

Demand

The MRO forecasted 2008-2009 Winter Non-Coincident Peak Total Internal Demand in the combined MRO US and MRO Canada is 43,080 MW, assuming normal weather conditions. This forecast is 2.1% above last winter's forecasted total demand of 42,204 MW and 3.9% higher than last year's actual winter peak demand of 41,450 MW. Any interruptible demand or DSM implemented during last year's peak load is unknown. The MRO 2008-2009 forecast Net Internal Demand is 41,539 MW, which is 1.9% higher than the 2007-2008 forecasted Net Internal Demand of 40,775 MW. The majority of this demand increase can be attributed to the very rapid load growth in the oil fields and coal bed methane fields in the Bakken Formation in western North Dakota and eastern Montana.

Peak demand uncertainty and variability due to extreme weather and other conditions are accounted for within the determination of adequate generation reserve margin levels. Both the MAPP GRSP members and the former MAIN members within MRO utilize a Load Forecast Uncertainty factor within the calculation for the Loss of Load Expectation (LOLE) and the percentage reserve margin necessary to obtain a LOLE of 0.1 day per year or 1 day in 10 years. The load forecast uncertainty considers uncertainties attributable to weather and economic conditions. Forecasts are developed for Saskatchewan to cover possible ranges in economic variations and other uncertainties such as weather using a Monte Carlo simulation model to reflect those uncertainties.

Each MRO member uses its own load forecasting methodology; some reported 50/50 forecast and some 90/10 forecast. In general, the peak demand forecast includes factors involving recent economic trends (industrial, commercial, agricultural, residential) and normal weather patterns. From a regional perspective, there were no changes in this year's forecast assumptions in comparison to last year.

MRO staff distributed the NERC Winter 2008-2009 data request spreadsheet to each LSE member within the MRO in the format received from NERC. The members populated these spreadsheets based on NERC and MRO instructions and submitted them to the MRO for processing by a predetermined due date. Internally, MRO staff compiled the individual

[1] The former MAIN members are Alliant Energy, Wisconsin Public Service Corp., Upper Peninsula Power Co., Wisconsin Public Power Inc., and Madison Gas and Electric. The American Transmission Company (ATCLLC) is the transmission owner which encompasses the last four former MAIN members and Alliant Energy-Wisconsin Power & Light, which is the Wisconsin portion of Alliant Energy. The ITC Midwest is the transmission provider for the Iowa and Minnesota portion of Alliant Energy.

[2] The other Canadian member is Manitoba Hydro which, for the purpose of this assessment, is included in the MAPP GRSP group.

spreadsheet submissions into a set of regional spreadsheets representing the MRO region as a whole as well as MRO U.S. and MRO Canada.

When the spreadsheet was initially distributed, MRO instructions emphasized to the LSEs that each MW of demand must be counted once and only once and that LSEs should carefully coordinate with their neighboring LSEs to ensure that double-counting would not occur in the regional compilations.

Interruptible Demand (800 MW, 1.8%) and Demand Side Management (DSM) (741 MW, 1.7%) programs, amounting to 3.5% of the MRO's Projected Total Internal Peak Demand of 44,072 MW are utilized by a number of MRO members. A wide variety of programs, including direct load control (such as electric appliance cycling) and interruptible load, may be used to reduce peak demand during the winter season.

Generation

The existing internal certain resources for the MRO US and Canada 2008-2009 winter are 55,587 MW. The existing internal uncertain resources for the MRO US and Canada 2008-2009 winter are 5,190 MW. Planned resources that are expected to be in service this winter are 762 MW. These values do not include firm or non-firm purchases and sales. The month of January was used in all cases to be consistent.

The nameplate capacity of the variable generation for the MRO is 4,924 MW. The variable resources for the MRO expected to be available at peak times is 984 MW, based on 20% of nameplate capacity. This value of nameplate capacity is used by the Midwest ISO when determining capacity of variable generation. It is also used by the MRO Model Building Subcommittee when building peak models.

The biomass portion of resources for the MRO expected to be available at peak times is 310 MW.

Reservoir water levels improved over the 2008 summer, but continue to remain below normal in Montana, North Dakota, and South Dakota, and will likely continue to reduce the magnitude and duration of power transfers out of northern MRO where the hydro resources are located. This will continue to contribute to the imports of power into the MRO region during peak load periods. The Manitoba water condition is normal and normal Manitoba-US transfers are expected. Manitoba Hydro manages its reservoir levels in preparation for the winter season such that there is adequate energy to meet daily energy demand throughout the winter.

SaskPower reservoirs are at normal conditions and regular operating regimes are expected. Reservoir levels are sufficient to meet both peak demand and the daily energy demand throughout the upcoming season.

The MRO region is not experiencing a drought or expecting any other conditions that would create capacity reductions.

The MRO region considers known and anticipated fuel supply or delivery issues in its assessment. Because the region has a large diversity in fuel supply, inventory management, and delivery methods, the MRO does not have a specific mitigation procedure in place to address fuel delivery problems. The MRO members do not foresee any significant fuel supply and fuel delivery issues for the upcoming 2008-2009 winter season. However, if problems occur, they will be addressed on a case by case basis. Therefore, there should be no apparent impacts to the reliability of meeting peak electrical demand.

Purchases and Sales

For the 2008-2009 winter season, the MRO is projecting total firm purchases of 776 MW from sources external to the MRO region. The MRO has approximately 960 MW of total projected sales to load outside of the MRO region. The net import/export of the MRO region can vary at peak load, depending on system conditions and market conditions.

Transfer capability from MRO Canada (Saskatchewan and Manitoba) into the MRO US is limited to 2,415 MW due to the operating security limits of the two interfaces between these two provinces and the US. The forecasted firm transfers from Manitoba to the US are 873 MW for the winter for 2008-2009.

Throughout the MRO region, firm transmission service is required for all generation resources that are utilized to provide firm capacity; therefore, that these firm generation resources are fully deliverable to the load. The MRO is forecast to meet the various reserve margin targets without needing to include energy-only, uncertain, or transmission-limited resources.

Currently, MRO members do not use Liquidated Damage Contracts as firm capacity resources.

Transmission Reliability Margins are calculated and reserved by the Transmission Providers within the MRO Region to assure that operating reserves can adequately be delivered. These operating reserves can include resources outside of the MRO Region since most MRO members participate in the Midwest Contingency Reserve Sharing Group.

Transmission

The following reinforcements include projects that have expected service dates from June 1, 2008 through December 31, 2008. Projects that went in service prior to June 1, 2008 were listed in the Summer 2008 Assessment.

Iowa

New wind farm generation is planned to be in service prior to (or during) this winter season. This includes new wind farms in Iowa near Adair, Walnut, Crystal Lake, Fernald, McIntire, Iowa Barton Township, Carroll, and Forest City. There was also an addition to the existing

Pomeroy/Pocahontas wind farm near Pomeroy, Iowa. Significant new transmission facilities that are planned to be placed into service prior to this winter season include:

- Grimes Tap to Bittersweet Road 161 kV. In service in October 2008
- Replacement of the 345/161 kV transformer at S.E. Polk.
- Monona-Victory 161 kV line upgrade. In service in December 2008.
- Carroll-Drager 161 kV line upgrade. In service in December 2008.
- Drager-Grand Junction 161 kV line upgrade. In service in December 2008.

Nebraska

Phase I of Nebraska Public Power District's Electric Transmission Reliability (ETR) Project for East-Central Nebraska was completed in June 2008. Phase I of the ETR Project entailed conversion to 345 kV of an existing 40 mile 230 kV transmission line from just north of Norfolk to a point just north of Columbus, expansion of the Hoskins Substation near Norfolk and construction of the new Shell Creek Substation north of Columbus. Completion of this phase of the project is expected to improve local area voltage support.

As a part of the Nebraska City Unit 2 power plant project, a new 50 mile 345 kV transmission line from the site of the Nebraska City 2 plant to a new substation southeast of Lincoln was energized in July 2008. The new line is expected to reduce the need for temporary operating guides during critical prior outages in and around Lincoln.

Under the same concept, a new 26 mile 345 kV transmission line that completes a northern tier segment around the city of Lincoln is expected to be energized by end of December 2008. This line is expected to reduce contingent overloading issues on critical assets in the Lincoln area, which in turn, will also reduce the need for temporary operating guides on these facilities.

Northern MRO

The Split Rock – Nobles Co 345 kV line was energized this summer, which completed the Xcel Energy 825 MW wind projects.

A new power plant at Cannon Falls Minnesota has been energized this past summer with a total output of 350 MW. The generating station is connected to the new Colville substation on the Cannon Falls – Empire 115 kV line and Cannon Falls – Spring Creek 161 kV line. As part of this project, Colville – Empire line capacity has been increased to 248 MVA. Several 69 kV lines were also upgraded to provide transmission service.

Xcel Energy has other capacity increases on its system. The capacity of Lakefield Junction – Lakefield generating station 345 kV line will be upgraded from 735 MVA to 918 MVA by the end of 2008 to provide an outlet to generation in Southwestern Minnesota. The Hyland Lake – Dean Lake 115 kV line in the Minneapolis-St. Paul Metro area was increased to 361 MVA this summer. The High Bridge Generating Station capacity increase was completed in the summer with the gross output from the plant at 610 MW. As part of this upgrade, High Bridge – Rogers Lake 115 kV line capacity was increased to 598 MVA.

Minnkota Power Cooperative is currently constructing the Pillsbury – Maple River 230 kV line. This line will serve as generation outlet for a number of wind farms located near Pillsbury, ND, that are currently under construction or in the planning stages. The in-service date is projected to be December 31, 2008.

The Dorsey Bus Enhancement project was completed, which consists of the Dorsey 230 kV bus being improved with the addition of four 230 kV circuit breakers and a new connecting bus. This project reduces the consequences of a category D event occurring at Dorsey station. Also the two lines (K21W & K22W) interconnecting Manitoba to Ontario were upgraded to 100°C design operation.

Saskatchewan

Saskatchewan has no new facilities to report for this season.

Wisconsin-Upper Michigan Systems

The WUMS electric transmission system encompasses the service territories of five Balancing Authorities: Alliant Energy-Wisconsin Power & Light, We Energies, Wisconsin Public Service Corporation, Madison Gas & Electric Company and Upper Peninsula Power Company. The WUMS system consists of 345, 230, 161, 138, 115 and 69 kV transmission facilities and is owned by American Transmission Company, LLC (ATCLLC). The operation of WUMS is coordinated between ATCLLC and Midwest ISO.

There are no transmission additions at 200 kV and above with expected in-service dates between June 2008 and December 2008. Significant upgrades to the 138 kV system are:

- Uprate North Appleton - Lost Dauphin 138 kV line. Already in-service.
- Uprate North Appleton - Mason St 138 kV line. Already in-service.
- Construct Clintonville - Werner West 138 kV line. Expected to be in service in November 2008.

Operational Issues

The MRO members are affiliated with five Planning Authorities: Midwest ISO, MAPP, American Transmission Company, Manitoba Hydro, and SaskPower. Midwest ISO also spans into the RFC and SERC regions. It has recently received approval to begin operation as a single Balancing Authority (BA) area. Midwest ISO operation as a BA is expected to occur in January 2009 as the operation of its Ancillary Service Market begins. There are two Reliability Coordinators within the MRO footprint – Midwest ISO and SaskPower. A number of MRO members are Midwest ISO-tariff members and therefore participate in the Midwest ISO market operations.

The MRO region has approximately 5,000 MW of nameplate wind generation. There is a potential ambient temperature restriction (e.g., some wind turbines can be restricted to operating in ambient temperatures between -20 degrees F and 104 degrees F) with wind turbines and there

may be a potential increase in operating reserves that could be required for this wind generation during ambient temperature limitations.

Iowa

Normal and reliable operation of the transmission system is expected in Iowa during the winter 2008-2009 season. A number of scheduled transmission and generation outages will take place in late fall 2008 and early winter 2008/2009 in order to perform regular maintenance or to accomplish scheduled projects. Outage scheduling studies have not identified any serious operational problems. Temporary operating guides will be issued for outages that might cause some loading or voltage concerns, or in case that unforeseen operating conditions and/or winter storm related events bring the system close to its operating limits.

A typical winter flow pattern characterized by a south-to-north system bias is expected to re-occur this winter season. These power transfers from the Southern and Eastern NERC Regions into the Northern MRO Region may cause some TLR/Congestion Management activities. In preparation for this season, the line rating of a flowgate on the South to North transmission path has been up-rated after replacing switches and relays. This upgrade will allow more transfer capability and enhanced reliability of the area.

The Iowa Operating Review Working Group and TOS have approved three new flowgates in Iowa during 2008 and eliminated two existing flowgates. The standing operating guides for all flowgates will be in effect during winter 2008/2009 to assist transmission operators and reliability coordinators in dealing with operational issues.

Nebraska

No significant operational concerns are expected in Nebraska during winter 2008/2009. Where large transfers might occur, operating guides and operating procedures have been put into place to maintain the reliable operation of the Nebraska regional transmission system.

Operational studies have been performed and will be updated as necessary for scheduled transmission and generation outages during the winter peak and off-peak time periods. Temporary operating guides will be issued for those outages which require actions or limitations to protect system operating limits.

In the past, the Nebraska/Iowa regional transmission system has experienced south-to-north transfers due to low hydro conditions and winter peak load conditions in northern MRO. These south-to-north transfers across the MRO system have a more profound impact on the eastern Nebraska system than on the western Nebraska system. All of the flowgates have approved operating guides and have proven effective in dealing with system conditions throughout the year.

Winter season load distributions are considered worst case for western Nebraska area stability. Operating guides have been developed which adequately protect the western Nebraska region for winter season load levels and maximum transfer conditions.

Northern MRO

A typical winter flow pattern characterized by a south-to-north system bias is expected to re-occur this winter season. These heavy south-to-north non-firm power transfers will likely cause some TLR/Congestion Management activities. Overall, the northern MRO system will be able to operate under all load and firm exchange levels while meeting the regional reliability criteria.

A number of bulk transmission outages are scheduled in the Northern MRO US region for maintenance; however no operating problems are expected. Temporary operating guides will be developed as necessary.

Saskatchewan

No significant operational concerns are expected, and operating guides are developed on an ongoing basis to deal with facility outages. Applicable operating guides can be found on the SaskPower OASIS node.

Wisconsin-Upper Michigan Systems

The Arrowhead – Stone Lake – Gardner Park (aka Arrowhead – Weston) 345 kV line went in service in January 2008; it improves the WUMS transmission reliability and transfer capability between Minnesota and Wisconsin. With the 345 kV line in-service, a new interface, the Minnesota Wisconsin EXport (MWEX) interface has been defined, which is comprised of Arrowhead-Stone Lake 345 kV line and King-Eau Claire 345kV line. The west to east transfer through the MWEX interface is constrained due to potential transient voltage recovery violation and voltage instability. The MWEX interface is managed as a reciprocal Interconnection Reliability Operating Limit (IROL) Flowgate of Midwest ISO and MAPP. An operating guide is in place which defines MWEX limits under system intact and various N-1 prior outage conditions.

The WUMS southern interface includes tie lines in the southwest and southeast interfaces. The southwest interface comprises the Wempletown – Paddock 345 kV line and Wempletown – Rockdale 345 kV line. The southeast interface comprises Zion – Arcadian 345 kV line, Zion – Pleasant Prairie 345 kV line and Zion – Lakeview 138 kV line. The WUMS southern interface is thermally limited for critical N-1 contingencies and voltage stability limited for critical N-2 contingencies during periods of heavy imports through the interface. An operating guide is in place that helps to manage these constraints.

Operating studies have been or will be performed for all scheduled transmission or generation outages. When necessary, temporary operating guides will be developed for managing the scheduled outages to ensure transmission reliability.

There are no known environmental or regulatory restrictions that could impact reliability during the 2008-2009 winter season.

Reliability Assessment Analysis

The MRO Reliability Assessment Committee is responsible for this 2008-2009 winter assessment. However, the MRO Transmission Assessment Subcommittee, the MRO Resource Assessment Subcommittee, the MAPP Transmission Operations Subcommittee, ATCLLC, and Saskatchewan Power Corporation all contribute to the preparation of the assessment. At the first step, MRO staff sent the NERC spreadsheets to the registered entities within the MRO and collected individual entity's load forecast, generation, and demand-side management data. The staff then combined the individual inputs from these spreadsheets to calculate the MRO regional totals. The staff also sought responses to the questions included in the NERC seasonal request letter, from Planning Authorities within the MRO region – MAPP, ATCLLC, and SaskPower. The MAPP Transmission Operations Subcommittee provided operational issues review from the various MAPP operating review working groups. Using all the information gathered from the process, the MRO Resource Assessment Subcommittee prepared the resource assessment portions, while the MRO Transmission Assessment Subcommittee prepared the transmission assessment and operational issues portions. Finally, the MRO Reliability Assessment Committee reviewed and approved the final draft before it was submitted to NERC.

Reserve margins are typically used as criteria for a target level as opposed to capacity margins. The MRO's projected 2008-2009 Winter Reserve Margin is 35.2% without Uncertain Resources.

For the MAPP GRSP members, resource adequacy is measured through the accreditation rules and procedures. The MAPP GRSP requires a 15% reserve capacity obligation (RCO) for predominantly thermal systems, and 10% reserve margins for predominantly hydro systems.[3] The RCO is established by the MAPP Restated Agreement and its governing authorities, i.e. MAPP Executive Committee and MAPP Pool Committee. This level of reserve requirements is subject to periodic review based on reserve requirements studies conducted regularly by MAPP.[4] The RCO requires the MAPP GRSP members to maintain their respective minimum reserve based on after-the-fact peak demand; i.e., the members are responsible for maintaining adequate generation to account for load forecast uncertainty. When a new peak occurs, the member will be required to maintain the minimum reserve based on that peak for the next 11 months, or until a new, higher peak takes place. Approximately 8,850 MW of generation in the MAPP GRSP (15.7% of MRO net internal capacity) is associated with predominantly hydro systems and only requires a 10% RCO.

[3] The MAPP GRSP Handbook, http://www.mapp.org/assets/policies/grsp_handbook_20080617.pdf.

[4] The previous MAPP reserve requirements study was conducted in 2003 by the MAPP Composite System Reliability Working Group. This study has not been posted on the MAPP website, but it is available upon request from MAPPCOR. The MAPP 2008 LOLE Study is ongoing and is expected to be completed by December 1, 2008.

For the former MAIN members, generation resource adequacy is assessed based on LOLE studies previously conducted by the MAIN region.[5] Although conducted on a yearly basis, MAIN's LOLE studies consistently recommended a minimum short-term planning reserve margin of 14%. Most recently, the Midwest Planning Reserve Sharing Group shows a required reserve margin of 14.2% for western MISO.

Saskatchewan's reliability criterion is based on annual expected unserved energy (EUE) analysis and equates to an approximate 13% reserve margin requirement.[6]

The projected MRO reserve margin of 35.2% for the 2008-2009 winter season is in excess of the above target Reserve Margins. This projected reserve margin, which includes only Certain Resources and net interchange, can be compared with last winter's projected reserve margin of 34.4% (considering committed resources and net interchange). With Uncertain Resources, the projected reserve margin is 36.6%, as compared to 34.6% for winter 2007-2008 with uncommitted resources included.

There are likely some differences in the way members submitted their generation data due to the significant changes in generation definitions in 2008. Additionally, variable generation (wind in particular), up to its nameplate capacity, was included as Uncertain Resources. Also, purchases and sales in 2007-2008 included purchases from IPPs within the MRO footprint since that is how data was previously collected. For 2008-2009 Winter, MRO staff attempted to include all IPP capacity as an internal resource, not as a purchase. Most large IPPs that are registered as Generator Owners MRO were properly captured. However, there are smaller IPPs that fall below registration criteria that have not been entirely captured. These additional IPPs would likely increase the projected capacity and reserve margins by an insignificant amount.

Generation deliverability is performed by Transmission Providers within the MRO region. Links to deliverability criteria within the MRO region are:

http://www.midwestiso.org/page/Generator+Interconnection

http://www.mappcor.org/content/policies.shtml

https://www.oatioasis.com/spc/

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[5] In the former MAIN region, MAIN Guide 6 adopted a resource adequacy criterion of 0.1 days/year, http://www.maininc.org/bg/guide6.pdf. Studies concerning LOLE calculations for the former MAIN Region are available. The 2005 study is located at http://www.maininc.org/files/MG6GenerationReliabilityStudy2005_14.pdf. Other studies are found by navigating through http://www.maininc.org/files/files.htm.

[6] Saskatchewan Power's generation adequacy studies for the province of Saskatchewan are not publicly posted or released. Information regarding these studies may be obtained by contacting SaskPower.

Throughout the MRO region, firm transmission service is required for all generation resources that are utilized to provide firm capacity; therefore, that these firm generation resources are fully deliverable to the load. The MRO expects to meet the various reserve margin targets without needing to include energy-only, uncertain, or transmission-limited resources.

There are no known deliverability concerns with the various methods used within the MRO region for firm deliverability.

No specific analysis is performed to ensure external resources are available and deliverable. However, to be counted as firm capacity the MAPP GRSP, former MAIN utilities, and Saskatchewan require external purchases to have a firm contract for capacity and firm transmission service.

The following discussion is based on the MRO/RFC/SPP/SERC-W 2008-2009 Winter Inter-regional Assessment.[7]

Non-simultaneous Total Import Capabilities into MRO from RFC-W, SERC-W, and SPP Regions:

Transfer Direction	TIC (MW)
RFC_W TO MRO	3064
SERC_W TO MRO	3764
SPP TO MRO	3164

The Total Import Capability (TIC) is equal to the net import into MRO (1964 MW) in the base case plus the First Contingency Incremental Transfer Capability (FCITC) obtained in the transfer analysis. These studies recognize constraints internal and external to the MRO.

Transient, voltage and small signal stability studies are performed as part of the near-term/long-term transmission assessments.[8] Voltage stability is also evaluated in the Midwest ISO's seasonal assessment.[9] The results of the Midwest ISO winter assessment were not available prior to the due date of this regional assessment. Reactive power resources are considered in on-going operational planning studies. No transient, voltage, or small signal stability issues are expected that impact reliability during the 2008-2009 winter season.

[7] Eastern Interconnection Reliability Assessment Group (ERAG) Winter 2008-2009 Inter-regional Transmission Assessment, MRO-RFC-SERC West-SPP (MRSWS) sub-group study (on-going), http://www.midwestreliability.org/

[8] 2008 MAPP System Performance Assessment; and MAPP Small Signal Stability Analysis Project Report, June 2007.

[9] Midwest ISO Winter 2008-2009 Assessment Studies (in progress), http://extranet.midwestiso.org/operations/seasonal.php

Several members within the MRO region have localized UVLS programs to prevent localized low voltage conditions. No UVLS has been installed in the MRO region to protect the Bulk Electric System.

Other Region-Specific Issues that were not mentioned above

There are no other known reliability concerns anticipated within the MRO region for 2008-2009 Winter.

Region Description

The Midwest Reliability Organization (MRO) has 48 members which include Cooperative, Canadian Utility, Federal Power Marketing Agency, Generator and/or Power Marketer, Small Investor Owned Utility, Large Investor Owned Utility, Municipal Utility, Regulatory Participant and Transmission System Operator. The MRO has 119 registered entities. The MRO Region as a whole is a summer peaking region. The MRO Region covers all or portions of Iowa, Illinois, Minnesota, Nebraska, North and South Dakota, Michigan, Montana, Wisconsin, and the provinces of Manitoba and Saskatchewan. The total geographic area is approximately 1,000,000 square miles with an approximate population of 20 million.

From: Burmester, Dale W. [mailto:dburmester@atcllc.com]
Sent: Tuesday, October 28, 2008 9:15 AM
To: mro-assess@midwestreliability.org
Cc: Burmester, Dale W.; Jo Anne McNabb
Subject: RE: [mro-assess] Upcoming RAC Meeting and Call for Reports

Chair Hoa and MRO-RAC,

My notes from the latest NERC TIS meeting are attached, along with the latest draft of the FIDVR white-paper. Here are the highlights from the meeting:

- I am on the Reactive Support / Control Sub-team. This group is working towards three deliverables: 1) A whitepaper on reactive support, 2) A "non-technical" presentation on reactive support, and 3) A SAR to update/replace VAR-001
- We are still collecting best practices/examples from around the county. If anyone (MAPP?) has any (public) methodology documents or other good (public) examples of how to analyze reactive resource requirements, please let me know and I will share them with the team.
- The Fault-Induced Delayed Voltage Recover white paper is nearly finalized; the latest draft is attached. The final version will be submitted to the NERC PC for approval at their December meeting.
- The NERC PC has asked all subcommittees to provide comments regarding the structure of the PC and subcommittees. There is significant pressure to hold the budget, yet continue to resolve the highest priority issues.

Please let me know if you have any questions.

take care,

dale

Dale Burmester
Manager - Economic Planning
Transmission Planning
American Transmission Company
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✉ dburmester@atcllc.com

NERC Transmission Issues Subcommittee (TIS)
October 21 and 22, 2008
Las Vegas, NV

- **Reactive Support / Control Subteam (October 20, 2008)**
  - Jim (NERC), Mark, Steve, John, Dale, Eric, Bob (NERC), Gary (Ameren)
  - RSCS met one day prior to TIS (Oct 20, 2008)
  - FERC would like to see equity issues addressed; we may not be able to resolve, but at least address them.
    - For example, is it appropriate to set a distribution PF requirement for all loads that interconnect to transmission?
  - NERC has contracted with Jim Robinson to work on this (Part 1 – static, Part 2 – dynamic)
  - Even if we conclude that "one size does not fit all", then can we provide guidance how to determine an appropriate balance.
  - The question is, perhaps, better phrased: How do you perform a study to determine when you need to add dynamic reactive support instead of static?
  - Reviewed project scope and requesting examples of how reactive resources are studied and deficiencies addressed (MAPP? examples)
  - Next meeting: WebEx Nov 21 10-noon CT
  - Next meeting: coincident w/ NERC PC … Dec. 2nd

- **NERC TIS – Introductions**
  - John, Mark, Dale, Patti, Jim, Steve, Gary (Ameren), Brandon, Eric, Quoc, Dana, Bob, Tom, David Till (via phone – partial)
- **Update from Reactive Support Control Subteam**
  - Jim Robinson
- **Fault-Induced Delayed Voltage Recovery - White Paper (Finalize)**
  - Need to finalize so we can present at December NERC PC meeting
  - Significant time and discussion regarding "definition" of FIDVR.
    - Resolved by splitting into two definitions (FIDVR and FIDVR event)
    - The definitions are not in the latest draft (attached) … yet.
  - Conf call to finalize after last round of comments: Nov 10 10:00-noon CT

- **NERC Structure**
  - PC has asked all subcommittees for comments regarding structure of PC and subcommittees. What is being done that does not need to be done?
  - TIS will review our scope of work and highlight (and provide examples) of reliability issues that we address that are not necessarily related to standards development. There is a lot of concern that many people are only worried about standards and standards development.

- **Future TIS Meetings**
  - Jan 21, 22 Phoenix, AZ
  - April 21,22 Atlanta, GA
  - July 14, 15 Boston, MA

DELAYED VOLTAGE RECOVERY

A NERC PLANNING COMMITTEE WHITE PAPER
DEVELOPED BY THE NERC TRANSMISSION ISSUES SUBCOMMITTEE

EXECUTIVE SUMMARY

A Delayed Voltage Recovery event, or more popularly today, a Fault Induced Delayed Voltage Recovery (FIDVR), is the phenomenon whereby system voltage remains at significantly reduced levels for several seconds after a transmission, subtransmission, or distribution fault has been cleared. Significant load loss due to motor protective device action can result, as can significant loss of generation, with a potential secondary effect of high system voltage due to load loss. A severe event can result in fast voltage collapse.

FIDVR is caused by highly concentrated induction motor loads with constant torque which stall in response to low voltages associated with system faults and draw excessive reactive power from the grid. FIDVR events become increasingly probable with continuing market penetration of low-inertia air conditioning loads without compressor undervoltage protection.

FIDVR events can—and have—occurred following faults cleared in as little as 3 cycles! The number and impact of FIDVR events can be decreased, but their elimination in the near term is unlikely.

Planning studies have not been able to replicate FIDVR events very accurately due to inaccurate modeling of loads. Uncorrected, this modeling deficiency has a two-fold detrimental effect. First, it can result in studies that do not adequately identify potential FIDVR events. Second, it can give false confidence in mitigation plans designed to prevent reoccurrence of events.

Fortunately, pockets of expertise exist that are actively developing better dynamic load models for aggregate induction motor load, utilizing results of extensive single-phase air conditioning performance tests and the detailed analyses of actual FIDVR events that have occurred in the past. This expertise generally developed by necessity in response to dramatic, local FIDVR events. However, venues such as the Department of Energy's "Workshop on Residential AC Stalling," this past April, are providing opportunities for the broader planning world to access this expertise to understand FIDVR—its causes and mitigation measures, as well as the relative urgency of developing and utilizing better dynamic load models to identify local potential for FIDVR.

The NERC Planning Committee is well positioned to play a very important and timely role in this education process. Five recurring issues need to be addressed.

- The FIDVR phenomenon must be more universally broadcast and understood throughout the electric utility planning community.
- Dynamic load models adequate for FIDVR studies should be developed, communicated, and appropriately customized for local use by grid planners.
- Post Event Analysis has been vital in finding model deficiencies and implementing corresponding improvements and should be promoted.
- Understanding and proper planning of power system protection and control action is important in preventing FIDVR events, which often are initiated by single-phase-to-ground faults that progress to multi-phase-to-ground faults because of protection inadequacy or failure.
- The degree of urgency that should be assigned to FIDVR studies is directly related to the degree of air conditioning load penetration. Guidelines or standards should not be issued to require the same level of effort from Alaskan planners as from those in California, Texas, Arizona, or Florida.

DELAYED VOLTAGE RECOVERY

A NERC PLANNING COMMITTEE WHITE PAPER
DEVELOPED BY THE NERC TRANSMISSION ISSUES SUBCOMMITTEE

INTRODUCTION

A Delayed Voltage Recovery event, or more popularly today, a Fault Induced Delayed Voltage Recovery (FIDVR), is the phenomenon whereby system voltage remains at significantly reduced levels for several seconds after a transmission, subtransmission, or distribution fault has been cleared (See Figure 1 for a typical FIDVR). Significant load loss due to motor protective device action can result, as can significant loss of generation, with a secondary effect of unacceptably high, potentially damaging system voltage sometimes following the load loss. A severe event can result in fast voltage collapse.

FIDVR events can—and have—occurred following faults cleared in as little as 3 cycles! The number and impact of FIDVR events can be decreased, but their elimination in the near term is unlikely.

FIDVR is caused by highly concentrated induction motor loads with constant torque which stall in response to low voltages associated with system faults and draw excessive reactive power from the grid. They require typically 5-6 times their steady-state current in this locked-rotor condition with the result that system voltage can be significantly depressed for seconds after the fault is cleared leading to cascade. Inability to adequately model dynamic loads has contributed to grid vulnerability to FIDVR.

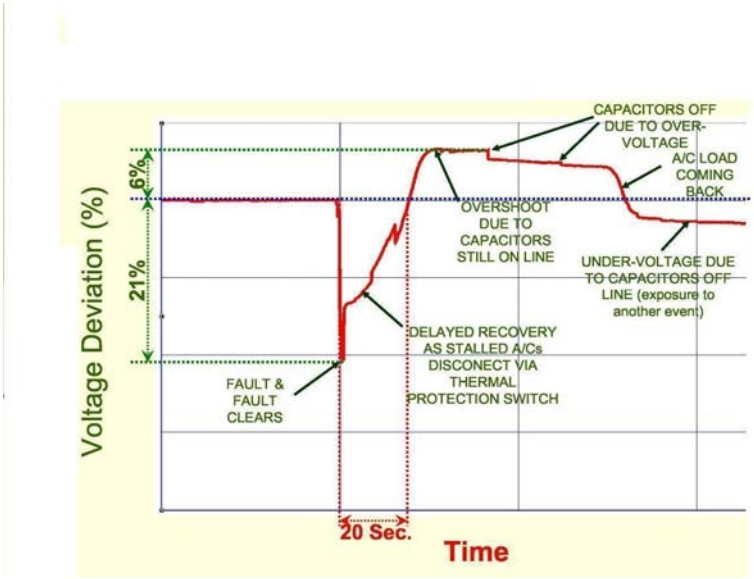

Figure 1: Typical FIDVR Following a 230-kV Transmission Fault in Southern California

The need for improved modeling of induction motor load with constant torque was noted at least as early as the mid-70s, documented in EPRI Project RP849-7 as well as several technical papers. Anecdotal evidence suggests that modeling improvement initiatives occurred in the early-70s as a result of the emergence of Power Quality as an end user concern, but these addressed the broader need to model a range of non-linear loads that were beginning to proliferate on the electric power system.

Anecdotal evidence suggests that the FIDVR phenomenon occurred several times in the mid-70s without a resulting understanding that inductive motor load, particularly high concentrations of single phase air conditioning (A/C) load, was the cause. However, this changed with an event in the Tennessee Valley Authority (TVA) service area on August 22, 1987, which Gary C. Bullock later published as "Cascading Voltage Collapse in West Tennessee." The event was precipitated when a 115-kV switch owned by Memphis Light, Gas, and Water Division arced and flashed phase-to-phase while an operator attempted to isolate a damaged airblast circuit breaker. Because the faulted bus lacked a bus differential protection scheme, the fault continued for more than a second and was eventually cleared by backup relays at remote locations. Motor loads in Memphis and the surrounding TVA area began to stall and draw large amounts of reactive power even after the fault was cleared. A depressed voltage condition developed on both the 161 and 500-kV systems in southwestern Tennessee and continued for 10 to 15 seconds. Reverse zone 3 line relays began to trip resulting in a cascade. Memphis lost 700 MW of load during the disturbance. A good portion of this was lost as thermal and overload protection on individual pump and A/C loads tripped. TVA lost an additional 565 MW of load after 13 and 161-kV substations were de-energized due to protective action in response to low and unbalanced voltages in the area. Incidentally, the concentration of A/C load is not surprising since this event developed on a Saturday—a *blistering Saturday* which set a rare, though short-lived, annual, seasonal system peak!

Post event analysis internally documented observation of the event, attempted and eventually performed simulation, established mitigation measures, and resulted as earlier noted in published documentation for the industry. The published paper noted several themes that would recur in documentation of post event analysis for later events.

- This event could not be duplicated using fault/load flow studies with conventional load models.
- Transient studies using lumped induction motor models as a portion of the load worked better but fell short of duplicating observed system voltage response.
- No real guidelines had been established to determine the nature of area summer transmission loads for large scale voltage perturbations.
- Without an accurate study model, validation of mitigation efforts depended heavily on subjective reasoning.

A series of comparable events followed relatively quickly across the continent with each evoking similar post event response, each confirming the findings from the prior events, and each advancing more detailed understanding of the common root phenomenon.

These events still continue despite the fact that pockets of FIDVR awareness and expertise have developed.

John W. Shaffer of Florida Power and Light Company (FPL) is one of the recognized, pioneering FIDVR experts. He detailed an August 18, 1988 event in his "Air Conditioner Response to Transmission Faults," published in 1997. A bolted 3-phase fault at the Flagami 230-kV switchyard initiated the event. Although the fault was cleared in 3.5 cycles, approximately 825 Mw of load was disconnected in the Miami area, almost all due to customer equipment protection. Area voltage was depressed for ten seconds after fault isolation. Simulation using high side load representation and a static model could not replicate the event. However, Mr. Shaffer was able to model the event by including motor and distribution models. The Introduction to his paper noted that "In the last ten years there have been at least eight events in which normally cleared multi-phase fault events in Southeast Florida have caused a significant drop in customer load (200-825 Mw).

Robert J. Yinger reported at the Department of Energy's "Workshop on Residential AC Stalling," that Southern California Edison's (SCE) first FIDVR event was observed in 1988. At least 53 subsequent events have occurred. He and SCE have been active in publishing FIDVR information as well as supporting research on and suggesting solutions for the phenomenon. Bradley R. Williams, Wayne R. Schmus and Douglas C. Dawson wrote a paper, "Transmission Voltage Recovery Delayed by Stalled Air-Conditioner Compressors," published in IEEE Transactions on Power Systems in August, 1992. The paper indicated that multiple FIDVR events occurred in SCE's desert regions during the peak air-conditioning period, including a major incident in June, 1990, which affected a 1000 square mile area of Riverside County. The paper also points to FIDVR incidents in the Sacramento area. Further, it attempted to model residential air-conditioners in power system studies.

In 1990, "Voltage Instabilities Subsequent to Short-circuit Recoveries," was submitted by M.Z. El-Sader, a faculty member of the Electrical Engineering Department of Assiut University, Assuit (Egypt). Clearly FIDVR was a concern beyond North America—reaching across the globe to areas of high induction motor load penetration.

On July 30, 1999, the Southern Balancing Authority experienced its first FIDVR event. A ccvt exploded in the Union City 230-kV Substation (Metro Atlanta). Debris was blown into the bus work which initiated an event that included three separate faults and two breaker failure operations. As a result, delayed voltage recovery of up to 15 seconds was observed over a large portion of North Georgia. 1900 MW of load and seven small generating units were tripped. Though well beyond events typically studied as even multi-contingency, low probability NERC Category D events, this event showed that the local transmission system had evolved to a state where FIDVR events are possible. Since the 1999 Union City event, planning and operating studies have resulted in a capital project plan and operational strategies which have been implemented since 2004. No significant FIDVR events have occurred in this area since the 1999 event.

In recent years, the field implementation of measurement units with higher sampling rates such as Phasor Measurement Units (PMUs) has indicated that FIDVR events are more prevalent that previously thought. These devices record typically 30 samples per second versus a typical SCADA system, which scans every 2-4 seconds and saves into a database one sample every 1-5 minutes. The higher sampling rate has been key to improved FIDVR identification and post event analysis.

Despite the generally isolated nature of FIDVR expertise, notable groups such as WECC have established key research/data initiatives to facilitate the development and promotion of detailed as well as aggregate inductive motor models for use in grid planning studies. WECC partners with air conditioning vendors as well as member utilities in this effort. NERC and TVA in their joint Stability Workshop conducted in May, 2007, in Chattanooga and DOE in its Workshop on Residential AC Stalling, conducted April, 2008, in Dallas, successfully identified individual engineers with FIDVR expertise, provided them a venue to educate the industry, and provided networking opportunities as well for attendees. Still, conditions appear to be trending unfavorably to an increasing FIDVR volume unless an even stronger, better coordinated industry response successfully intervenes.

Significantly, utility knowledge regarding FIDVR seems proportional to the geographical/educational proximity to an actual event; and yet, the industry entities and individuals most knowledgeable of—and with the healthiest technical respect for—FIDVR do not share a common definition or criteria for exactly what constitutes a FIDVR event. This has been reasonable since these definitions evolved within the contexts of specific areas being studied for FIDVR and their future vulnerabilities. A standard definition should be developed for general industry use.

The NERC Planning Committee supported by the Transmission Issues Subcommittee is well positioned to join and multiply the effectiveness of existing efforts to universally communicate information on FIDVR and to promote appropriate industry standards for its study and mitigation.

FIDVR ROOT CAUSE

FIDVR is caused by highly concentrated induction motor loads with constant torque which are not adequately modeled in planning studies. These motors can stall in response to low voltages associated with system faults and draw excessive reactive power from the grid. They require typically 5-6 times their steady-state current in this locked-rotor condition with the result that system voltage can be significantly depressed for seconds after the fault is cleared leading to cascade. Eventually, the stalled motors will trip by thermal protection with an inverse time-overcurrent characteristic. This can take from 3 to 20 seconds.

There are many types of loads connected to the grid, including motors, lighting, and electronics. Induction motor penetration is one of the more critical parameters that determine a transmission system's susceptibility to FIDVR events. Small, single-phase induction motors found in A/C equipment have low inertia and can thus stall within cycles as a result of fault voltages. Larger induction motors are also prone to stalling, though they should be slightly slower to stall and should do so at lower system voltage due to their larger inertia. Stalled induction motors present a high reactive loading to the transmission system further aggravating the initial fault voltage depression. As a result, additional induction motors can slow down and stall and create a voltage cascade.

FIDVR events are usually preceded by large, local loads with a high percentage of motor loads at the time of a fault. When system voltages depress usually for a second or longer, but under some conditions for as little as three cycles, induction motors begin to slow and their reactive power requirement increases. As the reactive power consumption increases, system voltage cannot recover and in some cases depresses even further. If voltages stay depressed long enough, generators trip or over-excitation limiters make them reduce reactive power output, and the system collapses.

FIDVR is worst when there is a concentration of "stall-prone" motors in a region. Not all motors are vulnerable to stalling. For example, large industrial motors often have contactors that will drop the motor out during voltage dips, thus limiting the negative impact of these motors. Large HVAC units may also have motor protection that will trip the unit offline before stalling occurs. Smaller HVAC units, however, may not have protection that will trip the unit off before stalling occurs. The mechanical torque of the compressor for these units tends to remain relatively constant for the first few seconds which makes the motors more prone to stalling.

Susceptibility to FIDVR is also very sensitive to location. A fault at a higher voltage level can depress the voltage over a wider area. Therefore, the potential for voltage to be reduced by a fault over a wide area, coupled with a large concentration of motor load in that area are important factors that indicate the likelihood of a FIDVR occurring.

This was the case in Arizona Public Service's (APS) July 28, 2003, Hassayampa event, reported by Dr. Baj Agrawal at DOE's recent "Workshop on Residential AC Stalling." A three phase fault on the 500-kV bus was cleared in only three cycles. Yet, FIDVR

occurred in the Phoenix area resulting in 440 MW load loss and 2600 MW generation loss with 90,000 customers affected. APS has since added significant dynamic support in the heart of Phoenix by installing combustion turbine generation as one facet of their mitigation plan. It should be noted that the generation loss in this event was traced to a protective relaying issue independent of FIDVR that has been corrected.

The secondary system overvoltage condition that can occur as a FIDVR event unfolds must also be noted. As John Shaffer determined, most of the load lost in the Flagami event in 1988 was due to action of customer equipment protection. Under certain circumstances, with enough load loss, this could result in system overvoltage. This was the case in the July 25, 1995, Arizona Public Service's "Pinnacle Peak Capacitor Fault Delayed Fault Clearing Slow Voltage Recovery Incident 1," reported by Dr. Baj Agrawal at the recent DOE, Workshop on Residential AC Stalling. Delayed clearing for this single-line to ground capacitor fault occurred at 16 cycles due to current transformer saturation. While there were sustained low voltages after fault clearing, enough load was lost that 10% overshoot in voltage recovery eventually occurred.

Of course, if significant load is lost, it is probable that area generation might be lost, also. This could moderate any movement toward overvoltage. This generation loss can be observed in many FIDVR events, Hassayampa and Union City—to name just two.

Finally, it must be recognized that protection and control (P&C) system deficiencies and/or (mis)operations often play a significant role in FIDVR events. For example, in the 1987 TVA event which resulted in the first documentation of the phenomenon, the faulted bus lacked bus differential protection. A FIDVR occurred in the same area on July 15, 2007, when a distribution gap type lightning arrestor initially failed to ground, but developed into a three-phase to ground fault. High side overcurrent relaying applied as a differential protection scheme eventually interrupted the fault as designed. However, the time delay on the relay was set too long, and 800-900 Mw of load were lost in this event. Had the available fault current not increased since the application of the setting, with the result that clearing was accomplished more quickly than originally designed, the system impact would have been even more severe.

These are just two examples—P&C impacts on FIDVR events abound. Guidance is needed on how to adequately include P&C actions and potential misoperations in FIDVR studies.

STUDY METHODOLOGY

Traditionally, “dynamic” simulations have been used to assess local system proximity to transient and oscillatory stability limits under various conditions. Voltage dependent static models have worked well for this because, while these instabilities typically result from voltage deviations that can be severe in magnitude, the deviations are usually short-lived versus those associated with FIDVR events.

However, analysis of FIDVR exposure requires truly dynamic simulations utilizing dynamic models with aggregate loads appropriately representing induction motor load penetration, including single-phase A/C load penetration, as well as approximating control action designed to de-energize loads for thermal overload and/or under-voltage conditions. The load model should contain other aggregate load components, such as voltage dependent load. However, the assumed induction motor load penetration is the most critical component of the load model.

Appropriate dynamic load models for FIDVR study have not historically been available for several reasons, but primarily because of inability to determine percent induction motor load for area buses, and because of limited understanding of A/C load dynamic characteristics. Methodologies for increasingly accurate aggregation of motor loads have been successively proposed since the 1970’s, and foundational understanding of the importance of A/C dynamic characteristics was attained in the 1990’s, but only recently has Western Electricity Coordinating Council (WECC) research produced the detailed understanding of A/C dynamic characteristics necessary to support a composite load model with a suitably accurate, aggregate A/C load component. Member utilities such as SCE, Bonneville Power Administration (BPA), and Pacific Gas & Electric (PG&E) partnered in this WECC research and testing effort, as did A/C vendors such as Emerson Climate Technologies and Trane Residential Systems. BPA, APS, SCE, and the California Energy Commission funded much of the effort, which has been led by Dr. Dmitry Kosterev, Chair of WECC’s Modeling and Validation Work Group and BPA employee. The result is a composite dynamic load model for use with General Electric’s PSLF software that meets the requirements above for FIDVR study. This model simulates stall behavior and thermal overload tripping and is currently under test by WECC’s MVWG team. The intent is to follow this development with a similar model for use with Power Technologies, Incorporated’s (PTI) PSS/E software.

Of course, the use of this model requires the aforementioned determination of induction motor load penetration, particularly A/C load. It is notable that SCE has determined that its A/C load penetration is 25% of coastal load and up to 60% of inland load on peak. Obviously, some western utilities are positioning to adequately model and study FIDVR.

The same is true in the east. Southern Company (SOCO) is one leader in the Eastern Interconnection in going beyond modeling and studying FIDVR to also educate

others in the industry to the phenomenon and the requirements for its study and mitigation.
SOCO has widely published the lessons learned from its Union City event in 1999. Robert Jones and Lee Taylor are leading in development of a user-defined load model for PTI's PSS/E software that also meets the requirements above for FIDVR study. Also, SOCO has installed load monitors at substations located in regions determined to be more prone to FIDVR events. Recorded dynamic behavior of the loads during fault events is expected to result in insight that can be utilized to refine load models used in dynamic simulations.

EPRI also has projects which span the continent aimed at synthesizing better load and generation models, including but not confined to dynamic modeling. One current project involves validation of models using system fault events.

Unfortunately, many North American electric utilities have neither the model nor the knowledge of the necessary percent induction motor load at the buses to adequately study and plan for FIDVR. Just determining the motor load as percent of total load can be challenging.

Some have attempted to determine this through analysis of actual fault response data relative to modeled performance. But, there are relationships between parameters that can be difficult to overcome. For example, recorded data may be available for a particular stall event on the system. When attempting to replicate the stall event, a stall condition may be simulated when the percentage of motor load is increased from 40% to 50%. But a similar stalling effect may be simulated by keeping the motor percentage at 40% and increasing the distribution impedance by a few percent. The interaction of these two parameters is such that it is difficult to accurately determine either quantity in the model utilizing parameter estimation methods. Instead of curve fitting, the true dynamic model must be determined.

Also, it must be noted that given the development of the dynamic models mentioned earlier, approximating the control action designed to de-energize loads for thermal overload and/or under-voltage conditions is still very difficult. Replicating FIDVR events that have already occurred is also usually difficult for this reason. The A/C loads stall or trip at relatively high voltage compared to the contactor drop-out of the larger, three-phase motors. It may be that prediction, or even replication of future events, will require the aid of a state estimator. A state estimator could be used to monitor the amount of load that is lost at each bus during the event.

Accurate exciter and power system stabilizer models are also important, and these are often not readily available. However, approximation of these values usually introduces less inaccuracy into the study than the load model parameters already noted.

The urgency of developing the dynamic FIDVR model, or of adopting a standard model and customizing it for local use, depends on local climate and resulting A/C penetration, and other details specific to an area or company.

An Example FIDVR Study Methodology

It might be helpful to detail a method to determine the stability limit in a region (amount of load that can be served depending on available generation).

Peak load levels will normally be worse for this type of stability event; therefore, peak cases should be used. However, sensitivity studies can be performed to investigate alternate generation dispatches when a critical generator may support the voltage in a local region; thus, an outage of that generator may create a vulnerability to FIDVR.

A FIDVR screening methodology may be used to identify locations for contingency studies. Steady state methods can be used to preliminarily identify large load pockets with relatively weak transmission support, or dynamic studies may be performed with typical values (estimated percent motor load, estimated distribution impedance, breaker clearing times, etc) to achieve the same purpose. In either case, the resulting list of potential FIDVR locations and the scenarios that challenge voltage stability should then be analyzed with dynamic simulations of three-phase normally cleared faults. If unacceptable voltage recovery is determined, mitigation must be considered, such as using an operating guide to dispatch additional generation in the area to attain faster voltage recovery, especially for the near-term. Faults with delayed clearing should also be investigated, weighing risks and consequences. If FIDVR vulnerability is discovered, then several load levels would need to be studied to identify generation or other options that may mitigate the problem at each load level. It may also be wise to perform additional studies with changes in load level and percentage of stall-prone motors to measure sensitivity of the results to load composition. If sufficient generation is not available within the operating horizon, other options may have to be considered including reducing load.

Solutions

If an election were held among the Transmission Planner community, the winning FIDVR solution would no doubt be the installation of equipment control devices to remove A/C and other induction motor loads from the grid prior to stalling for undervoltage conditions. This must be a component of the long range solution. This equipment protection could be a first step toward application of additional reactive sources such as SVCs to specifically protect against distribution system voltage variations. However, A/C standards necessary to achieve this will not be enacted overnight and retrofit of existing A/C units would likely be even more difficult to accomplish. It could also be argued that system exposure to FIDVR may be a symptom of a larger issue—inadequate dynamic reactive support. Consequently, use of grid solutions will be necessary at least until the threat level of A/C loads can be reduced. These grid solutions cannot ensure prevention of FIDVR events but may contain the events by limiting both their area of influence and their consequences.

The grid solutions include:

- Quicker clearing of faults

  Fault duration and location are critical factors that drive FIDVR risk. So, strategies to reduce expected fault duration at critical locations can be part of a cost effective plan to manage FIDVR exposures. This could include the reduction of breaker failure operation times, installation of relays selected primarily for their operating speed for faults determined to be critical, application of pilot or transfer trip relaying schemes, use of faster breakers, or replacement of gang operated breakers with independent pole operated breakers.

  However, this is obviously not a solution for those events in which 3-cycle clearing resulted in FIDVR!

- Addition of reactive sources or relocation of reactive sources relative to critical loads

  Following the Hassayampa event, APS added significant new combustion turbine generation in the heart of Phoenix to provide voltage support. The ten year plan developed for metropolitan Atlanta following the Union City event includes installation of a 260 MVAR Static Var Compensator (SVC) as well as relocation of key generating units to lower system voltage level interconnections.

  Similarly, Center Point Energy is in process of installing two 140 MVAR SVCs in the Houston metropolitan area to mitigate FIDVR events and Georgia Transmission Company (GTC) has installed a 260 MVAR unit planned by SOCO in the Atlanta metropolitan area.

The use of SVCs, STATCOMs, or even fast switched capacitors for additional dynamic support can be appropriate. However, because of their ability to contribute above their steady state MVAR capability during transient fault events, generators are superior dynamic MVAR sources. Also, SVCs and STATCOMs must be applied with particular attention to station service configuration and low voltage ride-through capability (see Appendix A). This attention has been given to the installations noted above.

New generation or transmission can reduce FIDVR vulnerability. However, new transmission can also allow a fault at to reduce voltages over a wider area during the fault, so each situation needs to be carefully analyzed.

The effectiveness of dynamic support is very dependent on its location. Dynamic simulation studies should be conducted to determine sites where dynamic support will provide optimal FIDVR mitigation. This information can be used to install transmission based dynamic MVARs, or for targeting regions for potential new generation.

- Limiting affected load

  Strategies to limit the amount of load subjected to low voltage should be considered for the most critical FIDVR fault locations. This could be accomplished through sectionalizing a tightly coupled transmission system. The impact on other limits, such as thermal and voltage levels, would also have to be considered in the analysis.

- Special Protection Schemes

  Special Protection Schemes (SPS) may be used as a safety net to confine the area impacted by FIDVR. If a voltage collapse develops in a load center because of a multi-contingency event, an SPS can contain the disturbance from spreading to larger grid—voltage collapse in Cleveland should not turn lights off in New York. However, use of an SPS for FIDVR mitigation would not comply with TPL-001-1 as now drafted because the SPS action would initiate Non-Consequential Load Loss. **So, while this action would be taken to benefit system reliability, it would constitute non-compliance—a Catch-22 that warrants attention.**

  In fact, the proposed requirements for Non-Consequential Load Loss will almost certainly be an issue for FIDVR regardless of whether an SPS is employed. For example, PGE experienced a sustained three-phase fault on the Newark – Ravenswood 230-kV line on July 12, 2008. The fault cleared within 5 cycles, but the 500-kV voltage near the fault experienced a decrease of more than 100-kV, and 350 to 440 MW of Non-Consequential Load Loss resulted. This loss was attributed to stalled motor loads.

- An undervoltage load shedding scheme (UVLS) can be an effective component in a strategy to manage FIDVR risk and limit the size of any potential disturbance. This should be viewed as a safety net. UVLS is generally viewed as ineffective in preventing fast voltage collapse, quite effective in preventing slow voltage collapse. Since changing system conditions may transform a fast-collapse scenario into a slow-collapse scenario, the UVLS option may still be considered when addressing identified fast-collapse vulnerability. In order to be effective, UVLS schemes need to trip load as soon as possible while ensuring security with backup relaying schemes.

- Promoting energy saving devices to reduce demand

  Promotion of the benefits of energy saving devices versus their costs can lower the total amount of load being served, perhaps reducing the likelihood of a FIDVR. However, this could also increase the A/C percent of total load with the opposite effect.

- Unit Level Solutions

  As mentioned earlier, promotion of grid-friendly A/C units with undervoltage protection could greatly reduce the likelihood of FIDVR over the long term.

  Long term, unit level solutions have two categories:

  a. Relays that disconnect A/C compressor motors when they stall.
     This method requires reliable detection of the stall condition to prevent customer inconvenience.
  b. Devices that allow A/C compressor motors to ride through transmission faults.
     This method would require design changes for compressor motors or addition of power electronic interfaces.

The response of the Southern Balancing Authority following the Union City event illustrates how solutions can be combined in formulating a complete mitigation plan. This mitigation plan included:

- Operational FIDVR risk reduction until 2008, avoiding unfavorable generation patterns
- Installation of a 260 MVAR SVC
- Relocation of key generating units from higher to lower voltage interconnections—effectively moving dynamic sources closer to loads
- Conversion of a 500-kV transmission line to 230-kV operation—with the increased line impedance reducing the amount of load subjected to low voltage for FIDVR resulting from faults at critical locations
- Planned new generation in North Georgia
- A three pronged strategy planned to mitigate multiple contingency events which includes faster breaker failure clearing at key stations, breaker replacements, and a UVLS scheme.

Recommendations

- The NERC Planning Committee (PC) endorse this white paper for use in further educating the industry to the FIDVR phenomenon.
- The PC support the WECC dynamic load model developed for PSLF and the SOCO dynamic load model developed for PSS/E and encourage their general use with local customization for FIDVR studies unless an adequate dynamic load model is already in use.
- The PC promote Post Event Analysis of all FIDVR events to ensure further data acquisition, understanding, and modeling expertise.
- The PC jointly task TIS and SPCTF with developing a guideline for adequately addressing P&C considerations in performance of FIDVR studies.
- The PC champion the concept of climate and load density driven level of effort in FIDVR activities.
- The PC task TIS with recommending a definition for FIDVR.
- The PC support the standardization of unit level solutions for FIDVR by A/C manufacturers.

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