



February 8, 2008

Transmission Assessment Subcommittee

Subject: February 20, 2008 Transmission Assessment Subcommittee Meeting
Agenda

Dear Subcommittee Members:

The Transmission Assessment Subcommittee is scheduled to meet February 20, 2008 beginning at 9:00am. The meeting agenda is attached.

The meeting will be held at the Holiday Inn Select located at Three Appletree Square; Bloomington, MN. If you require overnight accommodations please contact the hotel directly at (952) 854-9000. Please ask for the MRO rate of \$103/night + tax.

If you have any questions regarding this meeting please contact Sandy Humenansky via email at sl.humenansky@midwestreliability.org or via telephone at (651) 855-1730.

Regards,

Wenchun Zhu, Chair
Transmission Assessment Subcommittee

/s/

WZ:sh

Attachment

MEETING AGENDA
MIDWEST RELIABILITY ORGANIZATION
Transmission Assessment Subcommittee
Holiday Inn, Bloomington, MN
February 20, 2008 – 9:00 AM to 4:00 PM

1. **Call to Order**--Wenchun Zhu
2. **Determination of Quorum**--Andrew Lucero
3. **Standards of Conduct and Anti-Trust Guideline**--Wenchun Zhu
4. **Consent Agenda**--Wenchun Zhu
 - a. Approve Meeting Minutes from December 11, 2007 (Attachment 1 – Draft Meeting Minutes)
5. **NERC 2008 LTRA and Summer Assessment Data Request**--Salva Andiappan and John Seidel (Attachment 2 – NERC Requests)
6. **MRO Procedures for NERC Standard**--Andrew Lucero
 - a. *Review Spreadsheet* (Attachment 3)
 - b. *TAS Ownership and Assignments*
7. **SPS Review Team Status Update** -- Dan Jesberg, Terry Torgerson, David Diakiw and Wayne Guttormson
 - a. *Review PRC-014-0 – Special Protection System Assessment* (Attachment 4 – Draft Procedure)
 - b. *SPS Review Procedures for Existing SPS* (Attachment 5 – Draft Procedure by SPS Review Team Attachment 6 – MRO Existing SPS Database)
 - c. *New or Modified SPS* (Attachment 7 – Updated SPS Review Log)
 - i. Stone Lake SPS
 - ii. Weston 4 SPS
 - iii. Lakefield-Nobles SPS
 - iv. Langdon SPS
 - v. Ramsey SPS
 - vi. Tatanka SPS
 - vii. ATC SPS 004 Presque Isle Functional Modification Review Prior to June 2008
8. **ERAG Inter-regional Assessment Update**--Wenchun Zhu and Salva Andiappan
 - a. *2008 Assessment Studies*
 - b. *Methodology Discussions* (Attachment 8 – ERAG MRSWS Methodology Draft)
 - i. TAS Discussions and Comments on the Methodology
9. **RAC Meeting Update**--John Seidel and Andrew Lucero
10. **Other Business**--All
11. **Next Meeting**
12. **Adjourn**

**Agenda 1.
Call to Order**

**Agenda 2.
Determination of Quorum**

**Transmission Assessment Subcommittee
2008 Roster**

Name	Sector	Company
David Diakiw	Canada	Manitoba Hydro
Wayne Guttormson	Canada	Saskatchewan Power
Dan Belk	Dakotas	Western Area Power Administration
OPEN	Dakotas	
Dale Catherall	Iowa	Alliant Energy
Terry Harbour	Iowa	MidAmerican Energy Company
Dave Kempf	Minnesota	Great River Energy
Peter Schommer	Minnesota	Minnesota Power
Brian Brownlow	Nebraska	Nebraska Public Power District
Jeff Smedley	Nebraska	Omaha Public Power District
Wenchun Zhu, Chair	Wisconsin/Michigan	American Transmission Company
Terry Torgerson, V Chair	Wisconsin	Dairyland Power Cooperative
Zhixin Miao	MISO Liaison	Midwest ISO
Dennis Kimm	PAC Liaison	MidAmerican Energy Company
Peter Koegel	PAC Liaison	MAPPCOR
Ray Mason	RFC Liaison	ReliabilityFirst Corporation
Jay Caspary	SPP Liaison	Southwest Power Pool
Andrew Lucero	Secretary	
John Seidel	Alternate Secretary	
Adam Flink	Alternate Secretary	

Agenda 3.
Standards of Conduct/Anti-Trust Guidelines

Standards of Conduct Reminder

FERC Standards of Conduct prohibit MRO staff, committee, subcommittee and task force members from sharing non-public transmission sensitive information with anyone who is either an affiliate merchant or could be a conduit of information to an affiliate merchant.



Anti-trust Reminder

Participants in Midwest Reliability Organization meeting activities must refrain from the following when acting in their capacity as participants in Midwest Reliability Organization activities (i.e. meetings, conference calls, and informal discussions):

- Discussions involving pricing information; and
- Discussions of a participant's marketing strategies; and
- Discussions regarding how customers and geographical areas are to be divided among competitors; and
- Discussions concerning the exclusion of competitors from markets; and
- Discussions concerning boycotting or group refusals to deal with competitors, vendors, or suppliers.



Agenda 4.
Consent Agenda

**Agenda 4.a.
Consent Agenda**

Approve Meeting Minutes from December 11, 2007

**DRAFT MINUTES
MIDWEST RELIABILITY ORGANIZATION
Meeting of Transmission Assessment Subcommittee
December 11, 2007 – 9:00 AM – 2:00 PM
Conference Call**

1. Call to Order

Chairman Zhu called the meeting of the Midwest Reliability Organization (MRO) Transmission Assessment Subcommittee (TAS) to order at 9:03 am.

2. Determination of Quorum

The following members and guests were present:

Members Present

Wenchun Zhu, Chairperson, ATC
Zhixin Miao, MIS Liaison
David Diakiw, MHEB
Dave Kempf, GRE
Wayne Guttormson, SPC

Jeff Hart, MEC
Dan Belk, WAPA
Brian Brownlow, NPPD
Dale Catherall, ALT

Members Not Present

Andrew Lucero, Secretary
Pete Koegel, PAC Liaison
Terry Torgerson, Vice Chair, DPC
Peter Schommer, MP
Jay Caspary, SPP Liaison

Dennis Kimm, PAC Liaison
Ray Mason, RFC Liaison
John Seidel, Alternate Secretary
Jeff Smedley, OPPD
Jason Weiers, OTP

Guests

Salva Andiappan, MRO

3. Standards of Conduct and Anti-Trust Guidelines

Chairman Zhu reviewed the guidelines.

4. Consent Agenda

a. Approve meeting minutes from October 18, 2007.

Upon motion duly made by Mr. Kempf and seconded by Mr. Brownlow, the Transmission Assessment Subcommittee approved the October 18, 2007 minutes as is.

5. TAS Membership Issues

a. MidAmerican rep: Jeff Hart replacing Terry Harbour

Mr. Jeff Hart (MEC) will be replacing Mr. Terry Harbour (MEC) as the new Iowa representative to TAS. The RAC is expected to approve the replacement at their next meeting. RAC approved Mr. Jason Weiers (OTP) as the new Dakotas representative to the TAS.

Action item: Sandy Humenansky will add Mr. Jeff Hart (MEC) to the RAC March 5, 2008 agenda for RAC approval.

6. SPS Review Update

a. SPS review Log

Chairman Zhu informs the group that the SPSRT team is maintaining a log on all new SPS received by the task force. The Stone Lake, Trimont and Weston 4 SPS have been approved. Some additional information is being requested for the Tantanka SPS from the transmission owner.

b. SPS Review Status Update

Mr. Diakiw and Mr. Guttormson provided a brief update on the SPS review status. Mr. Guttormson indicated that the SPS information submitted to the task force is insufficient and that more detailed information such as what studies were done, study results, applicable standards/criteria and etc. will assist in the SPS review process.

Action item: The TAS SPSRT will develop a list of SPS information required for the SPS review process at the next TAS meeting.

c. Discussion Around Review of Existing SPS

Chairman Zhu informs the group that MRO will need to review all existing SPS in the region every 5 years as written in the PRC-014 standard, (Five Year Review of SPSs). The MRO PRS is developing the procedure and the TAS members will have the opportunity to review and comment the draft procedure when it becomes available.

There is a concern of the tremendous work load involve in reviewing the existing SPS with the current six volunteers from TAS and PRS. Mr. Brownlow suggested that the reviews of existing SPS should be done by the SPS Transmission Owners as this is how currently being done in the MAPP region. This would significantly reduce the burden of the SPSRT. Having the complete list of all existing SPS in the MRO region would help TAS to determine the amount of the work load required.

Action item: Mr. Dan Jesberg to provide the compiled SPS database and the draft RFC SPS procedure to TAS members.

Action item: Chairman Zhu will present the proposal of increasing the TAS SPSRT team from three to six members or creating an Ad-Hoc group for the review of existing SPS to the RAC members. Chairman Zhu will also propose the review of existing SPS done by SPS Transmission Owners to reduce the burden of the SPSRT.

7. RAC Meeting Highlight, UFLS

MRO is currently compliant with PRC-006 standard. The next step is for RAC is to begin a SAR process to develop a regional UFLS standard. The group feels that the NERC UFLS standard would line-up well with the MRO standard; however MRO will need to begin the SAR process first in order to have a regional standard. It is estimated that it would take at least a year from the initial SAR process to the final approval of a MRO UFLS standard. There is a great urgency for the RAC to begin the UFLS SAR process. The group also inquired into the status of the NERC Underfrequency Load Shedding Standard Drafting Team and development progress of the NERC UFLS standard.

Action item: Chairman Zhu will make a request to the RAC to expedite the UFLS SAR process for the development of a MRO UFLS program. In addition to propose the formations of a task force to develop the SAR.

Action item: Mr. Larry Brusseau to provide an update to the TAS on the status of the NERC Underfrequency Load Shedding Standard Drafting Team and the progress of the NERC UFLS standard.

8. ERAG 2008 Summer Assessment Update

Mr. Andiappan provided an update on the ERAG 2008 Summer Assessment project. At this time TAS members were requested to submit any model updates for submittal to the ERAG MMWG Coordinator. MRO will be performing the 2008 summer and winter assessment for the western ERAG study group. A more detailed study schedule will be available once the ERAG MMWG group finalizes the 2008 summer peak case. It is expected in late January the summer seasonal assessment to begin.

9. MRO Procedures for NERC Standards

a. Status and open discussions

Chairman Zhu informed the group that Mr. Seidel and Mr. Lucero are reviewing the MRO procedures for NERC standards. Mr. Guttormson further added that MRO Staff will need to review and update an existing MRO spreadsheet that contains the current standard and future standards and to review procedures from other regions.

Action item: Mr. Seidel and Mr. Lucero to provide a project update and the status of the MRO procedures for NERC standards at the next TAS meeting.

Action item: Mr. Brownlow will provide a spreadsheet that NPPD has developed to prioritize their work on NERC standards to the TAS members.

10. Other Business

None.

11. Next Meetings

The group scheduled a face to face meeting on February 20, 2008 from 9:00 am - 3:00 pm.

Future meetings:

a. 06-12-08, 9:00 am – 3:00 pm, Site TBD

b. 08-19-08, 9:00 am – 3:00 pm, Site TBD

c. 10-14-08, 9:00 am – 3:00 pm, Site TBD

12. Adjourn

The group adjourned at approximately 10:40 am.

Prepared and submitted by:
Salva Andiappan, MRO Staff
Andrew Lucero, TAS Secretary

Agenda 5. NERC 2 008 LTRA and Summer Assessment Data Request

From: John A. Seidel
Sent: Friday, January 18, 2008 2:06 PM
To: dalm@bepec.com; dkom@city.ames.ia.us; rchapman@city.ames.ia.us; Skokkinen@GREnergy.com; LThorson@gensys-energy.com; johnknof@hcpd.com; jdetour@hastingsutilities.com; dgroen@netamu.com; a.bonderman@a-m-u.net; tgernst@peengr.com; GaffiganT@mail2.harlanet.com; lpeterson@cityofpella.com; kstradley@les.com; nguyenh@mdu.mdures.com; bjcutors@NMPPENERGY.ORG; SCRyan@midamerican.com; nsever@hydro.mb.ca; david.niles@dahlen-berg.com; AndyR@utplus.com; lweerts@ci.hutchinson.mn.us; gary.domeier@ci.new-ulm.mn.us; ccarlson@wmu.willmar.mn.us; rnichols@mnpower.com; dsollom@minnkota.com; rhuebner@mpw.org; jps@mrenergy.com; tjowens@nppd.com; cory.huber@northwestern.com; jiverson@oppd.com; dechelberger@otpc.com; jsutton@rpu.org; pjegan@smmpa.org; jgienow@saskpower.sk.ca; belk@wapa.gov; tkomplin@wppisys.org; edward.j.johnson@xcelenergy.com; jfroehlich@nge.com; KWITTKO@wpsr.com; clarkeschroeder@alliantenergy.com; clunde@atcllc.com
Cc: Daniel P. Jesberg; Shel L. Berg; Matthew A. Couillard; mroras-mem@midwestreliability.org; mrorac-mem@midwestreliability.org
Subject: NERC 2008 LTRA and Summer Assessment Data Request

Attachments: NERC 2008 LTRA Instructions.doc; ERO-2008LTRA.xls; NERC 2008 Summer Instructions.doc; ERO-2008S.xls
NERC Assessment Data Request recipients:

Attached are two spreadsheets, one for the NERC Long-Term Reliability Assessment (LTRA) and one for the NERC 2008 Summer Assessment. Also attached are their instruction sheets that provide discussion and guidance for the requested data.

In past years, a multi-purpose spreadsheet had been sent to you by Matt Couillard (MAPPCOR) that would accommodate the data collections needed for the NERC LTRA, the NERC Seasonal Assessments, and the MAPPCOR Load and Capability Report that is used by the MAPP Generation Reserve Sharing Group (GRSP). This year, the NERC assessment requests and the MAPPCOR L&C requests will be separate. The NERC has made significant changes to Schedules 3A and 3B of the LTRA sheet and Schedule A of the summer sheet when compared to the data requests of previous years. This year these sheets are being forward to you exactly as they were received from NERC staff.

A couple of comments/clarifications on Schedules 3A, 3B and A of the spreadsheets:

- 1) NERC would like to determine how much wind nameplate exists, and how much is expected to be available at peak load. This will be determined through 6a1 and 6b1. For example, if a 100 MW nameplate wind farm is expected to deliver 15 MW at peak load, enter 15 MW into 6a1. 85 MW would then be entered into 6b1 as the "derated" amount that is not expected to be available at peak. The sum of these two values will provide the nameplate MW. The sections on Planned and Proposed wind should be entered similarly.
- 2) The instruction for Section 7b, proposed capacity, includes proposed units that are listed in an Interconnection Queue and/or proposed units that have requested an Interconnection Study. Data submitters should take care not to double count proposed units that may be in the queue more than once.
- 3) The instructions for Sections 10d and 11d, provisional capacity purchases and sales, allow for transactions that are in study mode and not yet negotiated. Data submitters should take care to include only those transactions that are reasonably expected to be approved and used for capacity. Care should be taken not to include transactions in the queue that may be speculative or redundant.

Please complete the attached forms and return them to Daniel Jesberg (MRO staff) at: dp.jesberg@midwestreliability.org by Friday, February, 22, 2008. If you have any questions regarding this data request, please contact myself or Daniel Jesberg at the MRO.

Regards-

John A. Seidel
MRO Staff
651-855-1716
ja.seidel@midwestreliability.org

Instructions for NERC Long-Term Assessment Data Reporting Form ERO-2008LTRA

Schedules 1A and 1B – Historical and Projected Peak Demand and Energy (supports Form EIA-411 submittal)

Enter monthly (1A) and annual (1B) peak demands and net energy for load for designated years in lines 1 through 6.

Schedule 1 is to be reported in total by each Regional Council for all utilities, groups of utilities, such as Council subregions, Independent System Operators, or Regional Transmission Operators, within that Council. The reported peak demands should comprise the sum of all non-coincident peak demands for the various operating entities within a NERC Region during the specified period. (Do not file coincident peak load.)

Schedules 3A and 3B– Demand and Capacity – Seasonal

Line 1 – Non-coincident Peak Demand (Starting Point) = 2+1a+1b-1c-1d

The gross load of the region/sub-region, assuming no load management or increased energy efficiency impacts, and no diversity between reporting entities.

Line 1a – New Conservation (Energy Efficiency)

The estimated impact of incremental passive energy efficiency programs. The increment represents the increase above the embedded amount from the base year. These impacts should be associated with programs to increase energy efficiency beyond its natural or normal growth.

Line 1b – Estimated Diversity

The difference between the region's/sub-region's peak and the sum of the peaks of the reporting entities (LSEs, control areas, zones, etc.). **GUIDANCE:** Only provide this data if the reporting area currently uses diversity.

Line 1c – Additions for non-member load (load served by non-registered LSE's in a region)

Adjustments to account for load of non-members, following the NERC standard MOD-16 “data submittal requirements shall stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.”

Line 1d – Stand-by Load Under Contract (Normally served by behind the meter generation)

The load specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for an outage of the customer's primary source. Stand-by Load is intended to be used infrequently by any one customer.

Line 2 – Total Internal Demand

The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some dispatchable demand response (such as Demand Bidding and Buy-Back).

Line 2a – Direct Control Load Management

Demand-side management that is under direct remote control of a control center. It is the magnitude of customer demand that can be interrupted at the time of the Regional Council seasonal peak by direct control of the System Operator by interrupting power supply to individual appliances or equipment on customer premises.

Line 2b – Contractually Interruptible (Curtable)

Load management achieved by a customer reducing its load upon notification from a control center. The interruption must be mandatory at times of system emergency. Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Council's seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Line 2c – Critical Peak-Pricing (CPP) with Control

Demand-side management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Line 2d – Load as a Capacity Resource

Demand-side resources that commit to pre-specified load reductions for certain system conditions.

Line 3 – Net Internal Demand 2-2a-2b-2c-2d

Total Internal Demand less Direct Control Load Management less Contractually Interruptible less Critical Peak-Pricing less Load as a Capacity Resource.

Line 4 – Demand Response Used for Ancillary Services (Data entered in line 4 and lines 4a through 4d will not be used to adjust net internal demand although some of these resources may make up a portion of lines 2a through 2c.)¹ = 4a+4b+4c+4d

Demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance.

Line 4a – Spinning Reserves

Demand-side resources that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

Line 4b – Non-Spinning Reserves

Demand-side resource not connected to the system but capable of serving demand within a specified time.

Line 4c – Regulation

Demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.

Line 4d – Emergency

Demand-side resource curtails during system and/or local capacity constraints.

Note: All capacity should be based on expected seasonally rated peak hour.

Line 5 – Total Internal Capacity = 6+7

The sum of Existing Capacity and Planned and Proposed Capacity Additions.

Line 6 – Existing Capacity/Existing Capacity Adjusted for Net of All Re-ratings, Retirements and Adjustments (“iron in the ground”) = 6a+6b

This capacity is the available existing generation connected to the electric system for the purpose of supplying electric load. The generation is available, expected to be in operable condition except for forced or scheduled outages that occur in the normal course of operations. Existing capacity does not include generation serving customers behind the meter. Customer load included by the Load Serving Entity is the customer load reduced by any behind the meter generation. For all capacity existing as of 12/31/2007. All other capacity should be designated as planned or proposed.

Line 6a – Certain Adjusted for Net of All Re-ratings, Retirements and Adjustments (“iron in the ground”)

Currently existing resources reasonably anticipated to be available to operate and is deliverable to or into the region.

Line 6a1 – Wind Expected On-Peak

The amount of existing wind capacity that is expected to be available on seasonal peak.

¹ Zero can be a legitimate answer

Line 6a2 – Solar Expected On-Peak

The amount of existing solar capacity that is expected to be available on seasonal peak.

Line 6a3 – Hydro Expected On-Peak

The amount of existing hydro capacity that is expected to be available on seasonal peak.

Line 6a4 – Biomass Expected On-Peak

The amount of existing biomass capacity that is expected to be available on seasonal peak.

Biomass defined: Organic nonfossil material of biological origin constituting a renewable energy source (wood, wood waste, municipal solid waste, landfill gas, ethanol and other biomass).

Line 6b – Uncertain Adjusted for Net of All Re-ratings, Retirements and Adjustments (“iron in the ground”)

Includes mothballed and portion of variable generation not included in “Certain”. GUIDANCE: This should include all other existing capacity not considered certain (line 6a).

Line 6b1 – Wind Derated On-Peak

The amount of existing wind capacity that is expected to be unavailable on seasonal peak.

Line 6b2 – Solar Derated On-Peak

The amount of existing solar capacity that is expected to be unavailable on seasonal peak.

Line 6b3 – Hydro Derated On-Peak

The amount of existing hydro capacity that is expected to be unavailable on seasonal peak. Pumped storage would not be considered as hydro.

Line 6b4 – Biomass Derated On-Peak

The amount of existing biomass capacity that is expected to be unavailable on seasonal peak.

Line 6b5 – Energy Only

Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources (may include generating capacity that can be delivered within the area but may be recallable to another area).

Line 6b6 – Inoperable

Expected to be unavailable, such as a scheduled outage, an extended outage, out of service or mothballed during the entire peak season.

Line 7 – Planned and Proposed Capacity Additions = 7a+7b

The sum of Planned and Proposed Capacity additions as defined below.

Line 7a – Planned Capacity

This category is for capacity which has achieved one or more of the following milestones:

- Construction has started
- At least one of the following regulatory permits approved
 - Site permit
 - Construction permit
 - Environmental permit
- Corporate management has approved at least one of the following
 - Included in a capital budget
 - BOD approved

Line 7a1 – Wind Expected On-Peak

The amount of planned wind capacity that is expected to be available on seasonal peak.

Line 7a2 – Wind Derate On-Peak

The amount of planned wind capacity that is expected to be unavailable on seasonal peak.

Line 7a3 – Solar Expected On-Peak

The amount of planned solar capacity that is expected to be available on seasonal peak.

Line 7a4 – Solar Derate On-Peak

The amount of planned solar capacity that is expected to be unavailable on seasonal peak.

Line 7a5 – Hydro Expected On-Peak

The amount of planned hydro capacity that is expected to be available on seasonal peak.

Line 7a6 – Hydro Derate On-Peak

The amount of planned hydro capacity that is expected to be unavailable on seasonal peak.

Line 7a7 – Biomass Expected On-Peak

The amount of planned biomass capacity that is expected to be available on seasonal peak.

Line 7a8 – Biomass Derate On-Peak

The amount of planned biomass capacity that is expected to be unavailable on seasonal peak.

Line 7a9 – Energy Only

Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources (may include generating capacity that can be delivered within the area but may be recallable to another area).

Line 7b – Proposed Capacity

This category includes generation that is not in a prior listed category, but has been identified through one or more of the following sources:

- Corporate announcement
- Included in integrated resource plan
- Generator Interconnection Queues
- Interconnection study requested

Line 7b1 – Wind Expected On-Peak

The amount of proposed wind capacity that is expected to be available on seasonal peak.

Line 7b2 – Wind Derate On-Peak

The amount of proposed wind capacity that is expected to be unavailable on seasonal peak.

Line 7b3 – Solar Expected On-Peak

The amount of proposed solar capacity that is expected to be available on seasonal peak.

Line 7b4 – Solar Derate On-Peak

The amount of proposed solar capacity that is expected to be unavailable on seasonal peak.

Line 7b5 – Hydro Expected On-Peak

The amount of proposed hydro capacity that is expected to be available on seasonal peak.

Line 7b6 – Hydro Derate On-Peak

The amount of proposed hydro capacity that is expected to be unavailable on seasonal peak.

Line 7b7 – Biomass Expected On-Peak

The amount of proposed biomass capacity that is expected to be available on seasonal peak.

Line 7b8 – Biomass Derate On-Peak

The amount of proposed biomass capacity that is expected to be unavailable on seasonal peak.

Line 7b9 – Energy Only

Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources (may include generating capacity that can be delivered within the area but may be recallable to another area).

Line 8 – Transmission-Limited Resources

The amount of transmission-limited generation resources that have known physical deliverability limitations to load within the region.

Example: If capacity is limited by both studied transmission limitations and generator derates, the generator derates take precedence. For example a 100 MW wind farm with a wind capacity variation reduction of 50 MW and a transmission limitation of 60 MW would take the 50 MW wind variation reduction first and list 10 MW in the transmission limitation.

Line 9 – Deliverable Internal Capacity = 5-7b-8-Derates-Energy Only-Inoperable

Total Internal Capacity less Proposed less Transmission-Limited Resources less all Derates less Energy Only less Inoperable.

Line 10 – Capacity Purchases and Incoming Adjustments = 10a+10b+10c+10d

The sum of all Firm, Non-firm, Expected and Provisional interregional purchases. GUIDANCE: Be sure not to double count jointly-owned plants or generators.

Line 10a – Firm

A firm contract has been signed and may be recallable.

Line 10b – Non-firm

A non-firm contract has been signed.

Line 10c – Expected

No contract executed, but in negotiation, projected, or other. These are expected to be firm.

Line 10d – Provisional

Transactions under study, but negotiations have not begun. These are expected to be provisionally firm.

Line 11 – Capacity Sales and Outgoing Adjustments = 11a+11b+11c+11d

The sum of all Firm, Non-firm, Expected and Provisional interregional sales. GUIDANCE: Be sure not to double count jointly-owned plants or generators.

Line 11a – Firm

A firm contract has been signed.

Line 11b – Non-firm

A non-firm contract has been signed and may be recallable.

Line 11c – Expected

No contract executed, but in negotiation, projected, or other. These are expected to be firm.

Line 11d – Provisional

Transactions under study, but negotiations have not begun. These are expected to be provisionally firm.

Line 12 – Net Capacity Resources = 9+10a+10c+10d-11a-11c-11d

Deliverable Internal Capacity plus the net of purchases and incoming adjustment and sales and outgoing adjustments that are expected to be firm. This excludes non-firm contracts (lines 10b and 11b).

Line 13 – Total Potential Resources = 5-8+10-11

Total Internal Capacity less Transmission-Limited Resources plus Capacity Purchases and Incoming Adjustments less Capacity Sales and Outgoing Adjustments.

Note: The items below support the EIA-411 submittal.

Line 21 – Distributed Generator Capacity < 1 MW

Report the amount of capacity that comprises distributed generators that have less than 1 MW of capacity.

Line 22 – Other Capacity < 1 MW

Report the amount of capacity that does not comprise distributed generators.

Line 23 – Distributed Generator Capacity >= 1 MW

Report the amount of capacity that comprises distributed generators that have 1 MW of capacity or greater.

Line 24 – Capacity Total from EIA-860 (summed by NERC from EIA-860 data)

Report the total amount of seasonal capacity for all generators reported on Form EIA-860 Schedule 3, as provided by EIA. GUIDANCE: U.S. only, not needed for Canada or Mexico.

Line 25 – EIA-860 Capacity Total minus Total Internal Capacity = 5-24

The difference between the capacity total from Form EIA-860 and Total Internal Capacity is attributable to a number of factors including, but not limited to, the following:

- Customer-owned generation that is truly “behind the meter” and offsets demand and energy that would otherwise be delivered by the load serving entity to the customer. This capacity is not included in the NERC capacity calculations because it is already reflected in Net Internal Demand.
- Emergency or peak shaving generation that a customer uses to reduce its metered demand. This capacity is not included in the NERC capacity calculations because it is already reflected in Net Internal Demand.
- Standby generator owned by customers used during power outages but otherwise not supplying capacity or energy.
- Differences in capacity reported by the generator owner on Form EIA-860 versus the seasonal net dependable capacity considered by the load serving entity.

GUIDANCE: U.S. only, not needed for Canada or Mexico.

General Notes

Numeric values

All numbers should be entered as MW in whole, positive values – no decimals or negatives (subtractions will be done in form)

Actual Year Data

For the purposes of this form, “actual-year data” should be submitted based on the same principles as the planning-based projected data. In order to avoid having the actual-year data change to operating data that is not comparable to planning data, please use the following ideas...

Do not include

- forced outages
- short-term transactions (purchases and sales)

Do include

- Changes to capacity due to return-to-service or new-to-service delays

Schedule 4 – Capacity Purchases, Sales and Incoming and Outgoing Transfers – Seasonal

Enter all actual and projected capacity purchases and sales (in megawatts) that involve entities outside of the Council or Reporting Region. The totals should agree with the totals in Schedule 3, Line 17a, **Purchases from Entities Outside the Region/Subregion** and Line 18a, **Sales to Entities Outside the Region/Subregion**.

Some data may be non-coincident due to differences in the month of the seasonal peaks for the purchaser and seller. An example would be a transfer that changes magnitude from July to August. The transfer would be reported in July by the selling party whose peak occurs in July and reported in August by the purchasing party whose peak occurs in August.

Please see **Schedule 3 – Demand and Capacity** section for more information on capacity physically located outside the regions' boundaries.

Other Party EIA Code and Other Party Name

Enter the five character numeric code for that party. A list of the EIA company codes, by reporting party name, is available at the [EIA website](#). If the name of the reporting party is not on this list, please enter the name of the party on the form and a code will be assigned by EIA.

Plant ID and Unit ID

Enter the EIA code for those unit specific purchases, sales, and transfers, if known.

Schedule 5 – Transmission Line Circuit Miles

Report transmission line data in WHOLE number circuit miles. Include lines that are under construction, committed to, or are in various stages of planning.

Schedule 6 – Projected Transmission Line Additions

This Schedule must be completed by each Regional Council for all transmission line additions at 230 kV and above projected for the ten-year period beginning with the year following the reporting year.

Line 1 – Terminal From Location

Enter the name of the beginning terminal point of the line.

Line 2 – Terminal To Location

Enter the name of the ending terminal point of the line.

Line 3 – Company Name

Enter the company name.

Line 4 – EIA Company Code

Identify each organization by the six-character code assigned by EIA.

Line 5 – Type of Organization

Identify the type of organization that best represents the line owner including the following types of utilities – Investor-owned (I), Municipality (M), Cooperative (C), State-owned (S), Federally-owned (F), or other (O).

Line 6 – Percent Ownership

If the transmission line will be jointly-owned, enter the percentages owned by each individual respondent.

Line 7 – Line Length

Enter miles between beginning and ending terminal points of the line, regardless of the number of conductors or circuits carried.

Line 8 – Line Type

Select physical location of the line conductor – overhead (OH), underground (UG), or submarine (SM).

Line 9 – Voltage Type

Select voltage as alternating current (AC) or direct current (DC).

Line 10 – Voltage Operating

Enter the voltage at which the line is normally operated in kilovolts (kV).

Line 11 – Voltage Design

Enter the voltage at which the line was designed to operate in kilovolts (kV).

Line 12 – Conductor Size

Enter the size of the line conductor in thousands of circular mils (MCM).

Line 13 – Conductor Material Type

Enter the line conductor material type – aluminum, ACCR, ACSR, copper, or other.

Line 14 – Bundling Arrangement

Enter the bundling arrangement/configuration of the line conductors – single, double, triple, quadruple, or other.

Line 15 – Circuits per Structure Present

Enter the current number of three-phase circuits on the structures of the line.

Line 16 – Circuits per Structure Ultimate

Enter the ultimate number of three-phase circuits that the structures of the line are designed to accommodate.

Line 17 – Pole/Tower Type

Identify the predominant pole/tower material for the line – wood, concrete, steel, combination, composite material, or other. Also include the type of structure – single pole, H-frame structure, tower, underground, or other.

Line 18 – Capacity Rating

Enter the normal load-carrying capacity of the line in millions of volt-amperes (MVA).

Line 19 – Projected In-Service Date

Enter the projected date the line will be energized under the control of the system operator. Please provide a month and year (e.g. 12-2009)

Schedule 7 – Annual Data on Transmission Line Outages for EHV Lines

In general terms, an Outage is defined as the removal from service availability of a generation unit, transmission line, or other facility for either scheduled (planned) or unscheduled (unplanned) reasons. For this reporting purpose, individual outage duration should be reported following similar company standards and/or regional reliability guidelines. The outage durations reported on the Form EIA-411 represent the annual summation (in hours) of all these events for the reporting NERC region.

The duration of an outage is the amount of time that the transmission line was completely de-energized. For preferred reporting practices, do not start recording duration until the line is completely deenergized and stop recording duration when the entire line is reenergized. If practices differ, please footnote.

Outages that occur on intertie lines between regions are to be reported only once by one or the other of the reporting regions.

Scheduled Outages

Information collected on scheduled outages is for the events where the duration was 1 hour or more in length. This includes line upgrades and the normal maintenance that is usually performed during non-peak load periods. Each time a line is removed from service, this is recorded as one scheduled outage (this includes accounting for periods where lines are returned to service on a periodic basis during a previously scheduled work period).

Unscheduled Outages

The information requested on unscheduled outages covers all events in which a line is automatically removed from service by system protection, or must be removed from service due to unforeseen circumstances. The unscheduled outage of any circuit continues until that circuit is restored to service. If company practices are different from this, please footnote.

- For any set of outages that have more than one cause, please report the initial cause (i.e., the cause that occurred first).
- For an outage of a circuit to be considered, the line(s) must be deenergized. If the line recloses and trips again within a minute of the initial outage, it is only considered one outage. The line would need to remain in service for longer than one minute between the breaker operations to be considered as two outages.
- ‘Failed tests’ are not considered additional outages. If the operator or dispatcher tries to energize a circuit that has a fault on it, and it immediately re-opens, this is considered a ‘failed test’ and is not an additional outage. However if the test ‘passed’ and the line remained in service for longer than one minute, any additional outages will be recorded as a new outage.
- Removal of any transmission line (including radials) from service is considered as an outage. However, transmission lines that are removed for system stability (such as

‘voltage control’) should not be reported as an outage. These may be reported separately as a footnote.

- When a tap off a transmission line is removed from service (scheduled or unscheduled outage) and the transmission line itself remains energized only the tap is considered out-of-service.

All transmission line outages involving Extra High Voltage (EHV) A.C. lines of 230 kV and above are to be aggregated by each Regional Council and reported on this schedule.

Line 1 – Applicable Voltage Class

If you are reporting an outage(s) of a voltage class that is not listed, identify the voltage class in the column labeled ‘Other (specify)’.

Line 2 – Number of Scheduled Outages

Report the total number of scheduled outages that occurred in the reporting period for each voltage class.

Line 3 – Number of Circuits Involved

Report the total number of “circuit outages”, that occurred during the reporting period, for all scheduled outages. For example, if there was one outage and five circuits are involved, the respondent should report 5 circuit outages. Alternatively, if there was one outage with two circuits involved and subsequently there is another outage with four circuits involved, the respondent should report 6 circuit outages, for each voltage class.

Line 4 – Scheduled Circuit-Hours Out of Service

Report the total scheduled circuit-hours out of service for all of the scheduled outages for each voltage class during the year. This is the sum across all circuits of the number of hours each circuit was out of service for scheduled reasons during the reporting period.

Line 5 – Number of Non-Momentary Unscheduled Outages

Report the number of non-momentary (lasting sixty seconds or longer) unscheduled outages that occurred during the reporting period for each voltage class.

Line 6 – Number of Circuits Involved

Report the total number of “circuit outages”, that occurred during the reporting period, for all unscheduled outages, both momentary and non-momentary. For example, if there is one outage and five circuits are involved, the respondent should report 5 circuit outages. Alternatively, if there was one outage with two circuits involved and subsequently there was another outage with four circuits involved, the respondent should report 6 circuit outages, for each voltage class.

Line 7 – Unscheduled Circuit-Hours Out of Service

Report the unscheduled circuit-hours out of service for all of the unscheduled outages for each voltage class during the year. This is the sum across all circuits of the number of hours each circuit was out of service for unscheduled reasons during the reporting period.

Line 8 – Weather

Includes all unscheduled outages caused by severe weather conditions (tornado, hurricane, lightning strikes, ice, high winds, etc.) that are the primary cause of the outage.

Line 9 – Animals, Fire and Smoke, Human Accidents

Includes the events caused by actions where animal movement or nesting impacts electrical operations of equipment or facilities. Actions by humans (accidents or intention) that not employed or under contract by the utility in the responsible area that impact operations will be reported. Fire and conditions linked to this from whatever event that started the fire/smoke conditions need to be accounted for in this category.

Line 10 – Vegetation

Includes outages initiated by vegetation in the proximity of transmission facilities. Reporting definition will be consistent with the NERC template and vegetation management criteria.

Line 11 – Operator Action

Includes any action traceable to employees and/or contactors for companies operating, maintaining, and/or providing assistance for actions that impacted any part of the operations of the Nation's power grids will be identified and reported in this category. Also, any failure or interpretation of standard industry practices and guidelines that cause an outage event will be reported in this category.

Line 12 – Equipment Failure

Includes failure of any line or terminal equipment.

Line 13 – Unknown

Any unknown sources should be reported in this category.

Line 14 – Other (*Calculated automatically by the spreadsheet*)

Includes all other causes, computed automatically to be the difference between 100% and the sum of Lines 8 through 13.

Schedule 9 – Fuel-Type Breakdown – Seasonal

Enter the seasonal actual and projected amounts of capacity for each fuel-type based upon Deliverable Internal Capacity (Line 16 from Schedule 3 – Demand and Capacity – Seasonal).

Form ERO-2008LTRA

Please enter the reporting region, subregion and country below:

Year	2008
Region	
Subregion	
Country	
Reporter Name	

NOTE: Please submit all Bulk Electric Transmission System Maps and Bulk Transmission Facility Power Flow Cases directly to EIA through the secure FTP site. See Form EIA-411 for additional instructions.

Schedule 1A - Historical and Projected Peak Demand and Energy - Monthly

Line#	Category	Units	Year	Codes	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
01	Actual - Peak Hour Demand	MW	2007	MDA												
02	Actual - Net Energy	GwH	2007	MNLA												
03	Reporting Year - Peak Hour Demand	MW	2008	MDF												
04	Reporting Year - Net Energy	GwH	2008	MNLF												
05	Next Year - Peak Hour Demand	MW	2009	MDS												
06	Next Year - Net Energy	GwH	2009	MNLS												

Please list or describe on what basis the demand is calculated (coincident, non-coincident, etc):

Schedule 1B - Historical and Projected Peak Demand and Energy - Annual

Line#	Category	Units	Codes	Projected										
				Actual										
				2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
2006/2007	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017				
07	Summer - Peak Hour Demand	MW	DS											
08	Winter - Peak Hour Demand	MW	DW											
09	Net Energy	GwH	NL											

Please list or describe on what basis the demand is calculated (coincident, non-coincident, monthly non-coincident, etc):

Schedule 3A - Demand and Capacity - Summer

SUMMER			Actual	Projected									
LINE #	DESCRIPTION	CODE	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
7b	Proposed (Note: The sum of 7b1 through 7b9 may not equal 7b and must be <= 7b)	DCSPR			0	0	0	0	0	0	0	0	0
7b1	Wind Expected On-Peak	DCSPRW			0	0	0	0	0	0	0	0	0
7b2	Wind Derate On-Peak				0	0	0	0	0	0	0	0	0
7b3	Solar Expected On-Peak				0	0	0	0	0	0	0	0	0
7b4	Solar Derate On-Peak				0	0	0	0	0	0	0	0	0
7b5	Hydro Expected On-Peak				0	0	0	0	0	0	0	0	0
7b6	Hydro Derate On-Peak				0	0	0	0	0	0	0	0	0
7b7	Biomass Expected On-Peak				0	0	0	0	0	0	0	0	0
7b8	Biomass Derate On-Peak				0	0	0	0	0	0	0	0	0
7b9	Energy Only	DCSPREO			0	0	0	0	0	0	0	0	0
8	Transmission-Limited Resources	DCSTO		0	0	0	0	0	0	0	0	0	0
9	DELIVERABLE INTERNAL CAPACITY = 5 - 7b - 8 - Derates - Energy Only - Inoperable	DCSTL	0	0	0	0	0	0	0	0	0	0	0
10	CAPACITY PURCHASES AND INCOMING ADJUSTMENTS = 10a+10b+10c+10d	DCSP	0	0	0	0	0	0	0	0	0	0	0
10a	Firm	DCSPF		0	0	0	0	0	0	0	0	0	0
10b	Non-firm	DCSPNF		0	0	0	0	0	0	0	0	0	0
10c	Expected - no contract executed, but in negotiation, projected, or other.	DCSPE		0	0	0	0	0	0	0	0	0	0
10d	Provisional – transactions under study, but negotiations have not begun.	DCSPP		0	0	0	0	0	0	0	0	0	0
11	CAPACITY SALES AND OUTGOING ADJUSTMENTS = 11a+11b+11c+11d	DCSS	0	0	0	0	0	0	0	0	0	0	0
11a	Firm	DCSSF		0	0	0	0	0	0	0	0	0	0
11b	Non-firm	DCSSNF		0	0	0	0	0	0	0	0	0	0
11c	Expected - no contract executed, but in negotiation, projected, or other.	DCSSE		0	0	0	0	0	0	0	0	0	0
11d	Provisional – transactions under study, but negotiations have not begun.	DCSSP		0	0	0	0	0	0	0	0	0	0
12	NET CAPACITY RESOURCES = 9+10a+10c+10d-11a-11c-11d	DCSNC	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL POTENTIAL RESOURCES = 5-8+10-11	DCSTP	0	0	0	0	0	0	0	0	0	0	0
21	Distributed Generator Capacity < 1 MW	DCSDGL											
22	Other Capacity < 1 MW	DCSOTL											
23	Distributed Generator Capacity >= 1 MW	DCSDGG											
24	Capacity Total from EIA-860	EIA860S											
25	EIA-860 Capacity Total less Total Internal Capacity	EIA860SD	0										

COLOR KEY:

- Summary Row - cell contains a formula
- Data Entry - cell data is used in a Summary Rows above and below
- No Data Entry - cell should remain blank or empty
- Data Entry - cell data sums to Summary Rows above and may be used in Summary Rows below.
- Data Entry - cell data may be used in Summary Rows below
- Information Only Summary Row

Schedule 3A - Demand and Capacity - Summer

SUMMER			Actual	Projected									
LINE #	DESCRIPTION	CODE	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
				Information Only Data Entry Row									

Schedule 3B - Demand and Capacity - Winter

WINTER			Actual	Projected									
LINE #	DESCRIPTION	CODE	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018
7b4	Solar Derate On-Peak				0	0	0	0	0	0	0	0	0
7b5	Hydro Expected On-Peak				0	0	0	0	0	0	0	0	0
7b6	Hydro Derate On-Peak				0	0	0	0	0	0	0	0	0
7b7	Biomass Expected On-Peak				0	0	0	0	0	0	0	0	0
7b8	Biomass Derate On-Peak				0	0	0	0	0	0	0	0	0
7b9	Energy Only	DCSPREO			0	0	0	0	0	0	0	0	0
8	Transmission-Limited Resources	DCSTO		0	0	0	0	0	0	0	0	0	0
9	DELIVERABLE INTERNAL CAPACITY = 5 - 7b - 8 - Derates - Energy Only - Inoperable	DCSTL	0	0	0	0	0	0	0	0	0	0	0
10	CAPACITY PURCHASES AND INCOMING ADJUSTMENTS = 10a+10b+10c+10d	DCSP	0	0	0	0	0	0	0	0	0	0	0
10a	Firm	DCSPF		0	0	0	0	0	0	0	0	0	0
10b	Non-firm	DCSPNF		0	0	0	0	0	0	0	0	0	0
10c	Expected - no contract executed, but in negotiation, projected, or other.	DCSPE		0	0	0	0	0	0	0	0	0	0
10d	Provisional – transactions under study, but negotiations have not begun.	DCSPP		0	0	0	0	0	0	0	0	0	0
11	CAPACITY SALES AND OUTGOING ADJUSTMENTS = 11a+11b+11c+11d	DCSS	0	0	0	0	0	0	0	0	0	0	0
11a	Firm	DCSSF		0	0	0	0	0	0	0	0	0	0
11b	Non-firm	DCSSNF		0	0	0	0	0	0	0	0	0	0
11c	Expected - no contract executed, but in negotiation, projected, or other.	DCSSE		0	0	0	0	0	0	0	0	0	0
11d	Provisional – transactions under study, but negotiations have not begun.	DCSSP		0	0	0	0	0	0	0	0	0	0
12	NET CAPACITY RESOURCES = 9+10a+10c+10d-11a-11c-11d	DCSNC	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL POTENTIAL RESOURCES = 5-8+10-11	DCSTP	0	0	0	0	0	0	0	0	0	0	0
21	Distributed Generator Capacity < 1 MW	DCSDGL											
22	Other Capacity < 1 MW	DCSOTL											
23	Distributed Generator Capacity >= 1 MW	DCSDGG											
24	Capacity Total from EIA-860	EIA860S											
25	EIA-860 Capacity Total less Total Internal Capacity	EIA860SD	0										

COLOR KEY:

	Summary Row - cell contains a formula
	Data Entry - cell data is used in a Summary Rows above and below
	No Data Entry - cell should remain blank or empty
	Data Entry - cell data sums to Summary Rows above and may be used in Summary Rows below.
	Data Entry - cell data may be used in Summary Rows below
	Information Only Summary Row
	Information Only Data Entry Row

Schedule 7A - Annual Data on Transmission Line Outages for EHV A.C. Lines

(Report following data for each applicable EHV Voltage Class)

1.	Applicable A.C. Voltage Class	230 kV (a)	345 kV (b)	500 kV (c)	765 kV (d)	Other (specify) (e)
Scheduled Outages for Specified Voltage Class						
2.	Number of Scheduled Outages					
3.	Number of Circuits Involved					
4.	Scheduled Circuit-Hours Out of Service					

Unscheduled Outages for Specified Voltage Class						
5.	Number of Non-Momentary Unscheduled Outages					
6.	Number of Circuits Involved					
7.	Unscheduled Circuit-Hours Out of Service					

Causal Categories for Unscheduled Outages of Specified Voltage Class (Percent)						
8.	Weather					
9.	Animals, Fire and Smoke, Human Accidents					
10.	Vegetation					
11.	Operator Action					
12.	Equipment Failure					
13.	Unknown					
14.	Other	100.00	100.00	100.00	100.00	100.00

Schedule 7B - Annual Data on Transmission Line Outages for EHV D.C. Lines

(Report following data for each applicable EHV Voltage Class)

1.	Applicable D.C. Voltage Class	± 100-199 kV (a)	± 200-299 kV (b)	± 300-399 kV (c)	± 400-499 kV (d)	± 500 kV or greater (e)
Scheduled Outages for Specified Voltage Class						
2.	Number of Scheduled Outages					
3.	Number of Circuits Involved					
4.	Scheduled Circuit-Hours Out of Service					
Unscheduled Outages for Specified Voltage Class						
5.	Number of Non-Momentary Unscheduled Outages					
6.	Number of Circuits Involved					
7.	Unscheduled Circuit-Hours Out of Service					
Causal Categories for Unscheduled Outages of Specified Voltage Class (Percent)						
8.	Weather					
9.	Animals, Fire and Smoke, Human Accidents					
10.	Vegetation					
11.	Operator Action					
12.	Equipment Failure					
13.	Unknown					
14.	Other	100.00	100.00	100.00	100.00	100.00

Schedule 9A - Fuel-Type Breakdown - Summer

SUMMER		Actual	Projected									
Category	Code	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Nuclear	CSNU											
Hydro	CSHY											
Pumped Storage	CSPS											
Geothermal	CSGE											
Wind	CSWD											
Coal	CSSTC											
Oil	CSSTO											
Gas	CSSTG											
Dual Fuel	CSSTDF											
Steam		0	0	0	0	0	0	0	0	0	0	0
Oil	CSCTO											
Gas	CSCTG											
Dual Fuel	CSCTDF											
Combustion Turbine		0	0	0	0	0	0	0	0	0	0	0
Oil	CSCCO											
Gas	CSCCG											
Dual Fuel	CSCCDF											
Combined Cycle		0	0	0	0	0	0	0	0	0	0	0
Other	CSOT											
Undetermined/Unknown	CSUN											
Total	CSTF	0	0	0	0	0	0	0	0	0	0	0

If fuels do not equal line 9 from Schedule 3 - Demand and Capacity - Seasonal, please explain here:

Schedule 9B - Fuel-Type Breakdown - Winter

WINTER		Actual	Projected									
Category	Code	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018
Nuclear	CWNU											
Hydro	CWHY											
Pumped Storage	CWPS											
Geothermal	CWGE											
Wind	CWWD											
Coal	CWSTC											
Oil	CWSTO											
Gas	CWSTG											
Dual Fuel	CWSTDF											
Steam		0	0	0	0	0	0	0	0	0	0	0
Oil	CWCTO											
Gas	CWCTG											
Dual Fuel	CWCTDF											
Combustion Turbine		0	0	0	0	0	0	0	0	0	0	0
Oil	CWCCO											
Gas	CWCCG											
Dual Fuel	CWCCDF											
Combined Cycle		0	0	0	0	0	0	0	0	0	0	0
Other	CWOT											
Undetermined/Unknown	CWUN											
Total	CWTF	0	0	0	0	0	0	0	0	0	0	0

If fuels do not equal line 9 from Schedule 3 - Demand and Capacity - Seasonal, please explain here:

Instructions for NERC Summer Assessment Data Reporting Form ERO-2008S

Schedule A – Projected Peak Demands and Resources

Line 1 – Non-coincident Peak Demand (Starting Point) = 2+1a+1b-1c-1d

The gross load of the region/sub-region, assuming no load management or increased energy efficiency impacts, and no diversity between reporting entities.

Line 1a – New Conservation (Energy Efficiency)

The estimated impact of incremental passive energy efficiency programs. The increment represents the increase above the embedded amount from the base year. These impacts should be associated with programs to increase energy efficiency beyond its natural or normal growth.

Line 1b – Estimated Diversity

The difference between the region's/sub-region's peak and the sum of the peaks of the reporting entities (LSEs, control areas, zones, etc.). **GUIDANCE:** Only provide this data if the reporting area currently uses diversity.

Line 1c – Additions for non-member load (load served by non-registered LSE's in a region)

Adjustments to account for load of non-members, following the NERC standard MOD-16 "data submittal requirements shall stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values."

Line 1d – Stand-by Load Under Contract (Normally served by behind the meter generation)

The load specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for an outage of the customer's primary source. Stand-by Load is intended to be used infrequently by any one customer.

Line 2 – Total Internal Demand

The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some dispatchable

demand response (such as Demand Bidding and Buy-Back).

Line 2a – Direct Control Load Management

Demand-side management that is under direct remote control of a control center. It is the magnitude of customer demand that can be interrupted at the time of the Regional Council seasonal peak by direct control of the System Operator by interrupting power supply to individual appliances or equipment on customer premises.

Line 2b – Contractually Interruptible (Curtable)

Load management achieved by a customer reducing its load upon notification from a control center. The interruption must be mandatory at times of system emergency. Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Council's seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Line 2c – Critical Peak-Pricing (CPP) with Control

Demand-side management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Line 2d – Load as a Capacity Resource

Demand-side resources that commit to pre-specified load reductions for certain system conditions.

Line 3 – Net Internal Demand 2-2a-2b-2c-2d

Total Internal Demand less Direct Control Load Management less Contractually Interruptible less Critical Peak-Pricing less Load as a Capacity Resource.

Line 4 – Demand Response Used for Ancillary Services (Data entered in line 4 and lines 4a through 4d will not be used to adjust net internal demand although some of these resources may make up a portion of lines 2a through 2c.)¹ = 4a+4b+4c+4d

Demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance.

Line 4a – Spinning Reserves

Demand-side resources that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

Line 4b – Non-Spinning Reserves

Demand-side resource not connected to the system but capable of serving demand within a specified time.

¹ Zero can be a legitimate answer

Line 4c – Regulation

Demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.

Line 4d – Emergency

Demand-side resource curtails during system and/or local capacity constraints.

Note: All capacity should be based on expected seasonally rated peak hour.

Line 5 – Total Internal Capacity = 6+7

The sum of Existing Capacity and Planned and Proposed Capacity Additions.

Line 6 – Existing Capacity/Existing Capacity Adjusted for Net of All Re-ratings, Retirements and Adjustments (“iron in the ground”) = 6a+6b

This capacity is the available existing generation connected to the electric system for the purpose of supplying electric load. The generation is available, expected to be in operable condition except for forced or scheduled outages that occur in the normal course of operations. Existing capacity does not include generation serving customers behind the meter. Customer load included by the Load Serving Entity is the customer load reduced by any behind the meter generation. For all capacity existing as of 12/31/2007. All other capacity should be designated as planned or proposed.

Line 6a – Certain Adjusted for Net of All Re-ratings, Retirements and Adjustments (“iron in the ground”)

Currently existing resources reasonably anticipated to be available to operate and is deliverable to or into the region.

Line 6a1 – Wind Expected On-Peak

The amount of existing wind capacity that is expected to be available on seasonal peak.

Line 6a2 – Solar Expected On-Peak

The amount of existing solar capacity that is expected to be available on seasonal peak.

Line 6a3 – Hydro Expected On-Peak

The amount of existing hydro capacity that is expected to be available on seasonal peak.

Line 6a4 – Biomass Expected On-Peak

The amount of existing biomass capacity that is expected to be available on seasonal peak.

Biomass defined: Organic nonfossil material of biological origin constituting a renewable energy source (wood, wood waste, municipal solid waste, landfill gas, ethanol and other biomass).

Line 6b – Uncertain Adjusted for Net of All Re-ratings, Retirements and Adjustments (“iron in the ground”)

Includes mothballed and portion of variable generation not included in “Certain”. GUIDANCE: This should include all other existing capacity not considered certain (line 6a).

Line 6b1 – Wind Derated On-Peak

The amount of existing wind capacity that is expected to be unavailable on seasonal peak.

Line 6b2 – Solar Derated On-Peak

The amount of existing solar capacity that is expected to be unavailable on seasonal peak.

Line 6b3 – Hydro Derated On-Peak

The amount of existing hydro capacity that is expected to be unavailable on seasonal peak. Pumped storage would not be considered as hydro.

Line 6b4 – Biomass Derated On-Peak

The amount of existing biomass capacity that is expected to be unavailable on seasonal peak.

Line 6b5 – Energy Only

Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources (may include generating capacity that can be delivered within the area but may be recallable to another area).

Line 6b6 – Inoperable

Expected to be unavailable, such as a scheduled outage, an extended outage, out of service or mothballed during the entire peak season.

Line 7 – Planned and Proposed Capacity Additions = 7a+7b

The sum of Planned and Proposed Capacity additions as defined below.

Line 7a – Planned Capacity

This category is for capacity which has achieved one or more of the following milestones:

- Construction has started
- At least one of the following regulatory permits approved
 - Site permit
 - Construction permit
 - Environmental permit
- Corporate management has approved at least one of the following
 - Included in a capital budget
 - BOD approved

Line 7a1 – Wind Expected On-Peak

The amount of planned wind capacity that is expected to be available on seasonal peak.

Line 7a2 – Wind Derate On-Peak

The amount of planned wind capacity that is expected to be unavailable on seasonal peak.

Line 7a3 – Solar Expected On-Peak

The amount of planned solar capacity that is expected to be available on seasonal peak.

Line 7a4 – Solar Derate On-Peak

The amount of planned solar capacity that is expected to be unavailable on seasonal peak.

Line 7a5 – Hydro Expected On-Peak

The amount of planned hydro capacity that is expected to be available on seasonal peak.

Line 7a6 – Hydro Derate On-Peak

The amount of planned hydro capacity that is expected to be unavailable on seasonal peak.

Line 7a7 – Biomass Expected On-Peak

The amount of planned biomass capacity that is expected to be available on seasonal peak.

Line 7a8 – Biomass Derate On-Peak

The amount of planned biomass capacity that is expected to be unavailable on seasonal peak.

Line 7a9 – Energy Only

Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources (may include generating capacity that can be delivered within the area but may be recallable to another area).

Line 7b – Proposed Capacity

This category includes generation that is not in a prior listed category, but has been identified through one or more of the following sources:

- Corporate announcement
- Included in integrated resource plan
- Generator Interconnection Queues
- Interconnection study requested

Line 7b1 – Wind Expected On-Peak

The amount of proposed wind capacity that is expected to be available on seasonal peak.

Line 7b2 – Wind Derate On-Peak

The amount of proposed wind capacity that is expected to be unavailable on seasonal peak.

Line 7b3 – Solar Expected On-Peak

The amount of proposed solar capacity that is expected to be available on seasonal peak.

Line 7b4 – Solar Derate On-Peak

The amount of proposed solar capacity that is expected to be unavailable on seasonal peak.

Line 7b5 – Hydro Expected On-Peak

The amount of proposed hydro capacity that is expected to be available on seasonal peak.

Line 7b6 – Hydro Derate On-Peak

The amount of proposed hydro capacity that is expected to be unavailable on seasonal peak.

Line 7b7 – Biomass Expected On-Peak

The amount of proposed biomass capacity that is expected to be available on seasonal peak.

Line 7b8 – Biomass Derate On-Peak

The amount of proposed biomass capacity that is expected to be unavailable on seasonal peak.

Line 7b9 – Energy Only

Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources (may include generating capacity that can be delivered within the area but may be recallable to another area).

Line 8 – Transmission-Limited Resources

The amount of transmission-limited generation resources that have known physical deliverability limitations to load within the region.

Example: If capacity is limited by both studied transmission limitations and generator derates, the generator derates take precedence. For example a 100 MW wind farm with a wind capacity variation reduction of 50 MW and a transmission limitation of 60 MW would take the 50 MW wind variation reduction first and list 10 MW in the transmission limitation.

Line 9 – Deliverable Internal Capacity = 5-7b-8-Derates-Energy Only-Inoperable

Total Internal Capacity less Proposed less Transmission-Limited Resources less all Derates less Energy Only less Inoperable.

Line 10 – Capacity Purchases and Incoming Adjustments = 10a+10b+10c+10d

The sum of all Firm, Non-firm, Expected and Provisional interregional purchases. GUIDANCE: Be sure not to double count jointly-owned plants or generators.

Line 10a – Firm

A firm contract has been signed and may be recallable.

Line 10b – Non-firm

A non-firm contract has been signed.

Line 10c – Expected

No contract executed, but in negotiation, projected, or other. These are expected to be firm.

Line 10d – Provisional

Transactions under study, but negotiations have not begun. These are expected to be provisionally firm.

Line 11 – Capacity Sales and Outgoing Adjustments = 11a+11b+11c+11d

The sum of all Firm, Non-firm, Expected and Provisional interregional sales. GUIDANCE: Be sure not to double count jointly-owned plants or generators.

Line 11a – Firm

A firm contract has been signed.

Line 11b – Non-firm

A non-firm contract has been signed and may be recallable.

Line 11c – Expected

No contract executed, but in negotiation, projected, or other. These are expected to be firm.

Line 11d – Provisional

Transactions under study, but negotiations have not begun. These are expected to be provisionally firm.

Line 12 – Net Capacity Resources = 9+10a+10c+10d-11a-11c-11d

Deliverable Internal Capacity plus the net of purchases and incoming adjustment and sales and outgoing adjustments that are expected to be firm. This excludes non-firm contracts (lines 10b and 11b).

Line 13 – Total Potential Resources = 5-8+10-11

Total Internal Capacity less Transmission-Limited Resources plus Capacity Purchases and Incoming Adjustments less Capacity Sales and Outgoing Adjustments.

Form ERO-2008S

Please enter the reporting region, subregion and country below:

Year	2008
Region	
Subregion	
Country	
Reporter Name	

Form ERO-2008S - Schedule A - Projected Peak Demands and Resources - Summer

SUMMER			Projected			
LINE #	DESCRIPTION	CODE	Jun-08	Jul-08	Aug-08	Sep-08
1	Unrestricted Non-coincident Peak Demand (Starting Point) = 2+1a+1b-1c-1d	DCSIN	0	0	0	0
1a	New Conservation (Energy Efficiency)	DCSEE		0	0	0
1b	Estimated Diversity	DCSED		0	0	0
1c	Additions for non-member load (load served by non-registered LSE's in a region)	DCSNM		0	0	0
1d	Stand-by Load Under Contract (Normally served by behind the meter generation)	DCSST		0	0	0
2	Total Internal Demand	DCSTI		0	0	0
2a	Direct Control Load Management	DCSLM		0	0	0
2b	Contractually Interruptible (Curtable)	DCSIT		0	0	0
2c	Critical Peak-Pricing (CPP) with Control	DCSCPP		0	0	0
2d	Load as a Capacity Resource	DCSLAR		0	0	0
3	Net Internal Demand = 2-2a-2b-2c-2d	DCSNI	0	0	0	0
4	Demand Response Used for Ancillary Services (Data entered in line 4 and lines 4a through 4d will not be used to adjust net internal demand although some of these resources may make up a portion of lines 2a through 2c.) = 4a+4b+4c+4d	DCSAS	0	0	0	0
4a	Spinning Reserves	DCSSR		0	0	0
4b	Non-Spinning Reserves	DCSNSR		0	0	0
4c	Regulation	DCSREG		0	0	0
4d	Emergency	DCSEMG		0	0	0
5	TOTAL INTERNAL CAPACITY = 6+7	DCST	0	0	0	0
6	EXISTING CAPACITY = 6a+6b	DCSTEX	0	0	0	0
6a	Certain (Note: The sum of 6a1 through 6a4 may not equal 6a and must be <= 6a)	DCSCER		0	0	0
6a1	Wind Expected On-Peak	DCSUW		0	0	0
6a2	Solar Expected On-Peak			0	0	0
6a3	Hydro Expected On-Peak			0	0	0
6a4	Biomass Expected On-Peak			0	0	0
6b	Uncertain (Note: The sum of 6b1 through 6b6 may not equal 6b and must be <= 6b)	DCSUNC		0	0	0
6b1	Wind Derate On-Peak	DCSUW		0	0	0
6b2	Solar Derate On-Peak			0	0	0
6b3	Hydro Derate On-Peak			0	0	0
6b4	Biomass Derate On-Peak			0	0	0
6b5	Energy Only	DCSUEO		0	0	0
6b6	Inoperable	DCSUIN		0	0	0
7	PLANNED AND PROPOSED CAPACITY ADDITIONS = 7a+7t	DCSPCA	0	0	0	0
7a	Planned (Note: The sum of 7a1 through 7a9 may not equal 7a and must be <= 7a)	DCSPL		0	0	0
7a1	Wind Expected On-Peak	DCSPLW		0	0	0
7a2	Wind Derate On-Peak			0	0	0

Form ERO-2008S - Schedule A - Projected Peak Demands and Resources - Summer

SUMMER			Projected			
LINE #	DESCRIPTION	CODE	Jun-08	Jul-08	Aug-08	Sep-08
7a3	Solar Expected On-Peak			0	0	0
7a4	Solar Derate On-Peak			0	0	0
7a5	Hydro Expected On-Peak			0	0	0
7a6	Hydro Derate On-Peak			0	0	0
7a7	Biomass Expected On-Peak			0	0	0
7a8	Biomass Derate On-Peak			0	0	0
7a9	Energy Only			0	0	0
7b	Proposed (Note: The sum of 7b1 through 7b9 may not equal 7b and must be <= 7b)					
		DCSPR		0	0	0
7b1	Wind Expected On-Peak	DCSPRW		0	0	0
7b2	Wind Derate On-Peak			0	0	0
7b3	Solar Expected On-Peak			0	0	0
7b4	Solar Derate On-Peak			0	0	0
7b5	Hydro Expected On-Peak			0	0	0
7b6	Hydro Derate On-Peak			0	0	0
7b7	Biomass Expected On-Peak			0	0	0
7b8	Biomass Derate On-Peak			0	0	0
7b9	Energy Only	DCSPREO		0	0	0
8	Transmission-Limited Resources	DCSTO		0	0	0
9	DELIVERABLE INTERNAL CAPACITY = 5 - 7b - 8 - Derates - Energy Only - Inoperable	DCSTL	0	0	0	0
10	CAPACITY PURCHASES AND INCOMING ADJUSTMENTS = 10a+10b+10c+10d	DCSP	0	0	0	0
10a	Firm	DCSPF		0	0	0
10b	Non-firm	DCSPNF		0	0	0
10c	Expected - no contract executed, but in negotiation, projected, or other.	DCSPE		0	0	0
10d	Provisional – transactions under study, but negotiations have not begun.	DCSPP		0	0	0
11	CAPACITY SALES AND OUTGOING ADJUSTMENTS = 11a+11b+11c+11d	DCSS	0	0	0	0
11a	Firm	DCSSF		0	0	0
11b	Non-firm	DCSSNF		0	0	0
11c	Expected - no contract executed, but in negotiation, projected, or other.	DCSSE		0	0	0
11d	Provisional – transactions under study, but negotiations have not begun.	DCSSP		0	0	0
12	NET CAPACITY RESOURCES = 9+10a+10c+10d-11a-11c-11d	DCSNC	0	0	0	0
13	TOTAL POTENTIAL RESOURCES = 5-8+10-11	DCSTP	0	0	0	0

Form ERO-2008S - Schedule B - Actual Peak Demands and Resources for Previous Summer

Actual Peak Demands* for 2007 Summer, MW			
Jun-07	Jul-07	Aug-07	Sep-07

All-Time Summer Peak Demand* MW	
All-Time Summer Peak Demand	Date

* Report on the same basis as described in Line 2 on Schedule A.

Actual Net Capacity Resources** for 2007 Summer, MW			
Jun-07	Jul-07	Aug-07	Sep-07

** Report on the same basis as described in Line 12 on Schedule A.

Agenda 6.
MRO Procedures for NERC Standards

Agenda 6.a. MRO Procedures for NERC Standards Review Spreadsheet

Standard #:	Title:	RAC Group Responsibility:					Other:	Comments:
		GTRTF	PRTF	TAS	RAS	MBS		
NERC RELIABILITY STANDARDS - MRO OWNERSHIP INDEX								
Red: Regulatory								
Approved								
Resource and Demand Balancing								
BAL-001-0	Real Power Balancing Control Performance						TBD	
BAL-002-0	Disturbance Control Performance						TBD	
BAL-003-0	Frequency Response and Bias				X			
BAL-004-0	Time Error Correction				X			
BAL-005-1	Automatic Generation Control				X			
BAL-006-1	Inadvertent Interchange				X			
Critical Infrastructure Protection								
CIP-001-1	Sabotage Reporting						TBD	
CIP-002-1	Critical Cyber Asset Identification							
CIP-003-1	Security Management Controls							
CIP-004-1	Personnel & Training							
CIP-005-1	Electronic Security Perimeter(s)							
CIP-006-1	Physical Security of Critical Cyber Assets							
CIP-007-1	Systems Security Management							
CIP-008-1	Incident Reporting and Response Planning							
CIP-009-1	Recovery Plans for Critical Cyber Assets							
Communications								
COM-001-1	Telecommunications (Future Effective Date)						TBD	
COM-002-2	Communications and Coordination (Future Effective Date)						TBD	
Emergency Preparedness and Operations								
EOP-001-0	Emergency Operations Planning				X			
EOP-002-2	Capacity and Energy Emergencies						Compl	
EOP-003-1	Load Shedding Plans			X	X			
EOP-004-1	Disturbance Reporting			X	X			
EOP-005-1	System Restoration Plans			X	X			
EOP-006-1	Reliability Coordination – System Restoration						RAC?	
EOP-007-0	Establish, Maintain, and Document a Regional Blackstart Capability Plan	X			X			
EOP-008-0	Plans for Loss of Control Center Functionality				X			
EOP-009-0	Documentation of Blackstart Generating Unit Test Results	X				X?		
Facilities Design, Connections and Maintenance								
FAC-001-0	Facility Connection Requirements				X			
FAC-002-0	Coordination of Plans for New Facilities				X			
FAC-003-1	Vegetation Management Program						Compl	
FAC-008-1	Facility Ratings Methodology				X			
FAC-009-1	Establish and Communicate Facility Ratings				X			
FAC-010-1	System Operating Limits Methodology for the Planning Horizon (Future Effective Date)						TBD	
FAC-011-1	System Operating Limits Methodology for the Operations Horizon (Future Effective Date)						TBD	
FAC-012-1	Transfer Capabilities Methodology						TBD	
FAC-013-1	Establish and Communicate Transfer Capabilities				X			
FAC-014-1	Establish and Communicate System Operating Limits (Future Effective Date)						TBD	
Interchange Scheduling and Coordination								
INT-001-2	Interchange Transaction Tagging						TBD	Compl?
INT-003-2	Interchange Transaction Implementation						TBD	Compl?
INT-004-1	Interchange Transaction Modifications						TBD	Compl?
INT-005-2	Interchange Authority Distributes Arranged Interchange						TBD	Compl?
INT-006-2	Response to Interchange Authority						TBD	Compl?
INT-007-1	Interchange Confirmation						TBD	Compl?
INT-008-2	Interchange Authority Distributes Status						TBD	Compl?
INT-009-1	Implementation of Interchange						TBD	Compl?
INT-010-1	Interchange Coordination Exemptions						TBD	Compl?
Interconnection Reliability Operations and Coordination								
IRO-001-1	Reliability Coordination – Responsibilities and Authorities						MISO	Compl?
IRO-002-1	Reliability Coordination – Facilities						MISO	Compl?
IRO-003-2	Reliability Coordination – Wide Area View						MISO	Compl?
IRO-004-1	Reliability Coordination – Operations Planning						MISO	Compl?
IRO-005-1	Reliability Coordination – Current-Day Operations						MISO	Compl?
IRO-006-3	Reliability Coordination – Transmission Loading Relief						MISO-RC	Compl?
IRO-014-1	Procedures to Support Coordination Between Reliability Coordinators						MISO-RC	Compl?
IRO-015-1	Notifications and Information Exchange Between Reliability Coordinators						MISO-RC	Compl?
IRO-016-1	Coordination of Real-time Activities Between Reliability Coordinators						MISO-RC	Compl?

Agenda 6.b.
MRO Procedures for NERC Standards
TAS ownership and Assignments

Agenda 7.
SPS Review Team Status Update

Agenda 7.a.
SPS Review Team Status Update
Review PRC-014-0 Special Protection System Assessment

**Midwest Reliability Organization Procedure for
Special Protection System Assessment**

A. Introduction - The following procedure developed by the MRO Protective Relay Subcommittee is considered a technical guideline and should be followed as good utility practice.

1. Title: Special Protection System Assessment

2. Reference NERC Standard PRC-014-0

3. Purpose: To ensure that all Special Protection Systems (SPSs) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and mis-operations are analyzed and corrected.

4. Applicability: The BES within the area under the MRO.

5. Most Recent Update: January 31, 2008

B. Requirements

R1. The MRO shall review the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC Reliability Standards and MRO criteria.

R1.1 SPS shall be reviewed during the year of its 5th anniversary following its last previous review. A record of "last reviewed" and "next scheduled" dates shall be maintained in the MRO SPS database along with other documentation required by NERC Standard PRC-013-0.

R1.1.1 The MRO may review an SPS at any time within the normal five year cycle if it is felt necessary to do so by the MRO.

R1.1.2 MRO to notify SPS owner(s) 90 calendar days in advance of an upcoming SPS re-review.

R1.2 The SPS owner(s) shall review/assess their SPS and the SPS documentation in accordance to PRC-012-0-MRO procedure at least once every five years. The following issues should be addressed in the review/assessment:

R1.2.1 Review BES changes that may require re-study of the SPS actions taken and/or the SPS design.

- R1.2.2** Report study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
 - R1.2.3** Review any old and/or new coordination requirements that may exist with other protection and control systems.
 - R1.2.4** Summarize past correct and incorrect SPS operations; include corrective actions taken for any misoperations over the past five year period.
 - R1.2.5** If SPS has operated in the past five year period, review and evaluate the effectiveness of the SPS performance.
- R1.3** SPS owner(s) to submit a report on its review of the SPS to the MRO within the 90 calendar day period. Submit report to:
 - mro-spsreview@midwestreliability.org
- R1.4** The SPS owner(s) may be required to present its review report of the SPS to the MRO. Presentation to be of sufficient technical detail so the group understands the scheme and can perform an assessment.
- R1.5** Any SPS modifications needed as a result of this review process shall follow the process outlined in the MRO procedure PRC-012-0-MRO.
- R1.6** The backlog of legacy SPSs within the MRO region will be integrated into the review process over a five year period beginning in July, 2008 with the intention of completing their reviews by the end of June, 2013.
 - R1.6.1** Priority of review of legacy SPSs shall be based on its impact to the wide area BES.
- R2.** The MRO shall provide either a summary report or a detailed report of its review of the assessment of the operation, coordination, and effectiveness of all SPSs installed within the MRO region to the affected RROs or NERC on request (within 30 calendar days).
- R3.** The documentation of the MRO SPS review group's assessment shall be filed in the MRO SPS database and shall include the following elements:
 - R3.1.** Identification of group conducting the assessment and the date the assessment was performed.
 - R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
 - R3.3.** Discussion of any coordination problems found between a SPS and other protection and control systems.

- R3.4.** Identification of SPSs that need a modification or decommissioning review (per the review process outlined in PRC-012-0-MRO) as a result of this review process.

Procedure Review and Approval

The MRO shall review this procedure at least every five years or following a revision of any relevant NERC standards and shall submit a review report and/or revised procedure for approval.

Agenda 7.b.
SPS Review Team Status Update
SPS Review Procedures for Existing SPS

To be sent under separate cover.

Agenda 7.c.
SPS Review Team Status Update
New or Modified SPS

Agenda 8.
ERAG Inter-Regional Assessment Update

Agenda 8.a.
ERAG Inter-Regional Assessment Update
2008 Assessment Studies

Agenda 8.b.
ERAG Inter-Regional Assessment Update
Methodology Discussions

Agenda 8.b.i.
ERAG Inter-Regional Assessment Update
Methodology Discussions
TAS Discussions and Comments on the Methodology

ERAG Study Guidelines and Methodology:

Study Base Case

- Starting Point : MMWG case, updated by the MMWG for each study.
- No base case or N-1 violations allowed, except where operation beyond modeled thermal limits is expected. Example of this is the existence of a short term emergency rating that was not modeled, or where a significant piece of transmission equipment has failed that places some load on a radial (or near radial) transmission system that is expected to be overloaded.
- If MISO/PJM market Dispatch is to be included, ~~there should not be any thermal overloads in the neighboring region~~
- N-1 violations due to market dispatch is not allowed
- Analysis of base case and first contingency overloads is to be included in the reports.

Commentary:

Do we need to address case quality in more detail?

Ability of the case to flat start?

No generators with unbound P_{MAX} or P_{MIN} values?

Correct ratings?

Do we need to address the quality of contingency lists?

Should they contain NERC category B1, B2, and B3 contingencies? Are tower and right of way contingencies to be permitted in the contingency lists? Should the contingencies be defined in adequate detail to permit AC contingency analysis?

Should contingencies be only breaker to breaker, or should they also include breaker to switch, and switch to switch? Should contingencies, flowgates, or interfaces be established to represent known voltage constraints in a DC based analysis?

End Commentary

Transfer Test level:

Test levels are to be high enough for transmission limits to appear. For some transfer directions, there will be technical limits to test levels that will need to be honored. (Import test levels do not need to be higher than 30% of the importing areas load, and export test levels can be capped at 5000 to 6000 MW, due to linear assumptions becoming less valid at higher levels.)

- ~~Use P_{max} - P_{gen} based of Designated Network Resources (DNRs)~~
- ~~Include merchant generation only to the level where they are deliverable (no local or stability limits)~~

- ~~Renewable units (e.g. Wind) should be included to the level based on the historical output (?)~~

Export Subsystem:

- Same criteria as Test Transfer
- Pmax on units should be honored
- Exclude from export participation any generator with known local or stability limitations to being increased
- Undispatchable units (e.g. Wind, some hydro, some dynamic devices) should be excluded from export participation.
- Units on maintenance outages, forced outages, retired or mothballed should be excluded from export participation.
- Units that would not be called upon to run during an emergency should be excluded from participation. (In the vicinity of Chicago for instance, there are generators that have no viable access to natural gas during the winter months, and thus should not participate in exports in a winter study.)
- Should insufficient generation be available to test transmission strength, load points are to be added.
- The make-up of the export subsystem does not need to be a function of the test level, provided that Pgen limits are honored.

Commentary:

The size and boundaries of the import and export areas greatly affects the limits that are found. Large subsystems will tend to identify limits that are “global” in nature, while smaller subsystems will tend to identify limits that are “local” in nature. The nature of FCITC calculations, where generators within an import or export subsystem are modeled as moving uniformly tends to find more limits near the boundaries of the subsystems than internal to the subsystems, particularly when the subsystems are relatively large. The size and boundaries of import and export subsystems in ERAG studies needs to be defined.

Also affecting the study results is the selection of participation factor cut-offs. For a given size subsystem, a 2% cutoff will tend to find more local limits than a 5% cutoff. The selection of the participation factor cut-off needs to be defined.

The FCITC approach to transmission analysis was developed during an era when computer capabilities were much less than they are now, and when visibility by operators of the transmission system was much lower, and transmission expansion plans were less coordinated. With the emergence of large energy and capacity markets, large transmission operators, Reliability Coordinators, and increased computer capability, ERAG should be considering alternatives to the FCITC approach to transmission analysis.

What risks to the transmission system should we be trying to identify in an FCITC based analysis? Is there a better way to identify those risks?

End Commentary

- ~~Should not exceed contract path limit (if applicable)~~

Import Subsystem:

- Based on P_{gen} — ~~P_{min} of on-line units~~
- ~~Generators with extremely low probability of being out may be excluded from import participation (Plant with 8 generators, of which only 4 are modeled as being on).~~ ~~on Gas/Oil units~~
-
- The import subsystem is to be made up of generators spread through the import area.
- The make-up of the import subsystem does not need to be a function of the test level, provided that P_{zero} limits are honored.
- ~~Base Load units (e.g. Nuclear, Coal) should be excluded.~~ ~~SAH~~
- ~~Must-Run units should be excluded~~
- ~~P_{min} on units should be honored~~

Study Results:

- “Negative FCITCs” are not allowed, ~~unless operating beyond first contingency limits is expected during the study period.~~ Negative FCITC represents base case ~~or overload under N-1 overload~~ condition which should be mitigated during base case development.
- ~~There is little correlation between FCITC values and ability to reliably serve load. However, if FCITC is very low (e.g. 10% of Test Transfer) or a limiting facility and contingency appear for numerous transfers tested, a proper explanation is needed. of why the importing region can serve their load reliably under the stress load scenario.~~
- Following factors should be included in the write-up:
 - ~~(Omit: Available Operating Guide should be in the contingency list, and limits without the guide should not be reported as an FCITC limit.)~~
 - Redispatch Option
 - Reserve capacity
 - ~~(Omit: CBM/ TRM are commercial terms for determining how much transmission can be sold, they have no business being mentioned in a reliability study.)~~ ~~considered~~
 -
- FCTTC should be reported where applicable.
 - $FCTTC = FCITC + \text{Net base Transfer}$

- FCTTC can not be calculated for transfer directions where markets are split (MRO to/from RFC), and is meaningless when a transfer limit was created by the market dispatch. In these cases TIC (as defined by RFC and MRO) is to be reported.
- Simultaneous transfers plot ~~will~~should be included ~~if they indicate any meaningful results~~. If new constraint showed up that drops the base transfer significantly, a mitigation plan (~~operating guide~~, redispatch) should be included in the report to address this concern. ~~The contingency list should include the use of operating guides as needed. (In the NPCC-RFC process, the creation of a new basecase with additional transfers and operating guides implemented is used to address some operating guides instead of adjusting the contingency list.)~~

Agenda 9.
RAC Meeting Update

**Agenda 10.
Other Business**

**Agenda 11.
Next Meeting**

**Agenda 12.
Adjourn**
