September 2010 10-Year Assessment
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Planning criteria

This document describes the system planning criteria that ATC will utilize to ensure that the ATC transmission system is adequate to support effective competition in energy markets, reliably deliver power to systems connected to and customers dependent upon ATC's transmission system, provide support to distribution systems interconnected to ATC's transmission system and deliver energy from existing and new generation facilities connected to the ATC transmission system. This document may be revised from time to time in response to changes in industry standards, new system conditions, new technologies being employed and new operating procedures, as appropriate. The criteria described below will be subject to change at any time at ATC's discretion. Situations that could precipitate such a change could include, but are not limited to, new system conditions, extraordinary events, safety issues, operation issues, maintenance issues, customer requests, regulatory requirements and Regional Entity or NERC requirements.

The planning criteria are listed under the following headings:

1) System performance criteria
2) Capacity benefit margin criteria
3) Transmission reserve margin criteria
4) Facility rating criteria
5) Model building criteria
6) Facility condition criteria
7) Planning zones
8) System alternatives
9) Load forecast criteria
10) Economic criteria
11) Environmental criteria
12) Other considerations

1. *SYSTEM PERFORMANCE CRITERIA*

System performance over a ten year planning horizon will be assessed at least annually. Such assessments will involve steady state simulations and, as appropriate, dynamic simulations.

Steady state assessments

Steady state assessments include the consideration of the following system load conditions:

1) Summer peak
2) Summer 90/10 peak
3) Summer shoulder peak
4) Winter peak
5) Fall/spring off-peak
6) Light load
7) Minimum load

The first three load conditions above will be assessed in all long-range planning studies. The last four load conditions may be considered when more detailed analyses are being conducted of specific alternatives developed to solve a particular problem. The specific criterion associated with each of the load conditions above is provided in Load Forecasting Criteria**.**

General applications of the steady state cases:

1) **Summer peak** - Determination of summer peaking area seasonal load serving and regional supply limitations, including voltage security assessments.
2) **Summer 90/10 peak** - Considered in the NERC Category B (loss of single element) analysis to help us determine whether extreme weather conditions may require unusual measures to meet unexpected load. The 90/10 forecast will be used to help prioritize and stage projects but it will not necessarily be used as the sole reason to justify projects.
3) **Summer shoulder peak** - This intermediate load level case type is used primarily to evaluate contingencies where transmission equipment may be intentionally outaged for maintenance or testing purposes in addition to assessing system biases or high system imports into the ATC foot print..
4) **Winter peak** – Determination of winter peaking area seasonal load serving limitations.
5) **Fall/spring off-peak** - This intermediate load level case is used primarily to evaluate contingencies where transmission equipment may be intentionally

outaged for maintenance or testing purposes and identify seasonal regional transfer impacts.

6) **Light load** - The light load level case is used to study the possibility of high voltages on the power system, capacitor switching studies, and potential equipment overloads near base load power plants due to reduced local demand. (The light load case model is representative of many more hours in the year than the minimum load model).
7) **Minimum load** – The minimum load case is used for determinations of adequate voltage control during minimum load conditions when few generating units are on-line.

Dynamic stability assessments

The dynamics cases are built to be consistent with the regional dynamics database except for the load modeling, which may consist of appropriate load and motor modeling for voltage stability assessments. Dynamic stability assessments will include consideration of the following system load conditions:

1) Summer peak
2) Light load

General applications of the dynamics cases:

a. **Summer peak** – This load condition is typically used for voltage stability studies to determine whether system disturbances during peak load conditions cause voltage instability. Also, since the performance of wind generators is more closely linked to system voltage performance, summer peak cases should be considered when assessing the performance of wind generation.
b. **Light load** – This load condition is typically used for dynamic stability assessments in order to assess the angular stability of synchronous machines (i.e. fossil fuel generators). Empirically, it is noted that the dynamic performance of synchronous machines is worse in lighter load conditions likely due to lower field excitation current.

1.1 STEADY STATE PERFORMANCE ASSESSMENT

Steady state performance assessments incorporating Operating Guides are done to identify potential transmission system vulnerabilities over a reasonable range of future scenarios. The steady state system performance criteria to be utilized by ATC shall include:

A. Normal conditions (NERC Category A)

1) No transmission element (transmission circuit, transformer, etc.) should experience loading in excess of its normal rating for NERC Category A conditions. This criterion should apply for a reasonably broad range of forecasted system demands and associated generation dispatch conditions.
(Applicable NERC Standard: TPL-001-0-R1)

2) The acceptable voltage range is 95 percent to 105 percent of nominal voltage for NERC Category A conditions. Such measurements shall be made at the high side of transmission-to-distribution transformers. We will consider voltage levels outside of this range, if they are acceptable to the affected transmission customer. Exceptions for certain interconnected entities are evaluated accordingly. All voltage criteria should be met with the net generator reactive power limited to 90 percent of the reported reactive power capability.
(Applicable NERC Standards: TPL-001-0-R1)

B. Loss of Single Element Conditions (NERC Category B)

1) No transmission element should experience loading in excess of its applicable emergency rating for applicable NERC Category B contingencies. This criterion should be applied for a reasonably broad range of forecasted system demands and associated generation dispatch conditions. Load curtailment may not be utilized in planning studies for overload relief. Field switching may not be considered as acceptable measures for achieving immediate overload relief for breaker-to-breaker contingencies. For restoration after breaker-to-breaker contingencies, field switching, Load Tap Changer (LTC) adjustments, Operating Guides and/or generator redispatch may be considered as acceptable measures to bring element loading levels below appropriate limits.

   System design should ensure that loading in excess of any Interconnection Reliability Operating Limit (IROL) can be reduced to achieve a reliable state within 30 minutes. Temporary excursions above the applicable emergency rating are acceptable if a Special Protection System (SPS) will reduce loadings automatically (i.e. no manual intervention) to an acceptable loading level in an acceptable timeframe. The acceptable loading level after SPS operation cannot exceed the applicable emergency rating and the acceptable timeframe is determined by the type

of violation that will occur if left unmitigated (e.g., clearance violation may take several minutes whereas exceeding a relay trip setting may result in an essentially instantaneous trip).
(Applicable NERC Standard: TPL-002-0-R1)

2) Under applicable NERC Category B contingencies, the temporary acceptable voltage range is 90 percent to 110 percent of the system nominal voltage. Exceptions for certain interconnected entities are evaluated accordingly. Load shedding or field switching are not acceptable measures for achieving immediate voltage restoration for breaker-to-breaker contingencies. For restoration after breaker-to-breaker contingencies, field switching, LTC adjustments, Operating Guides and/or generator redispatch may be considered as acceptable measures to bring voltage levels within appropriate limits.

   System design should ensure that voltage levels outside of any Interconnection Reliability Operating Limit (IROL) can be restored to achieve a reliable state within 30 minutes. These voltage criteria should be met with the net generator reactive power limited to 95 percent of the applicable reactive power capability. Temporary excursions below 90% or above 110% of system nominal voltage are acceptable if a Special Protection System (SPS) or control of shunt compensation will automatically (i.e. no operator intervention) restore system voltage to temporary acceptable voltage levels (i.e. 90% to 110%) within an acceptable timeframe. The acceptable timeframe will be situation dependent and may need to be reviewed with E&C Services.
   (Applicable NERC Standard: TPL-002-0-R1)

3) The steady state system operating point of selected ATC areas should be at least 10% away from the nose of the P-V curve to assure adequate system voltage stability and reactive power resources. This 10 percent P-V margin is chosen to reflect uncertainties in load forecasting and modeling, as well as to provide a reasonable margin of safety.

4) For assessments conducted using applicable MRO and RFC region-wide firm load and interchange levels (i.e. no market or non-firm system bias), generator real power output should not be limited under NERC Category B contingency conditions. We will consider a lower level of transmission service if requested by a transmission customer.

C. Loss of multiple element conditions (NERC Category C)

1) No transmission element should experience loading in excess of its applicable emergency rating for applicable NERC Category C contingencies. This criterion should be applied for a reasonably broad range of forecasted system demands and associated generation dispatch conditions. Overload relief methods may include

supervisory controlled or automatic switching of circuits, generation redispatch, or firm service curtailments, as well as minimal planned load shedding. The transmission element loading should be reduced to within the normal ratings within the time frame of the applicable ratings.
(Applicable NERC Standard: TPL-003-0-R1)

2) Under applicable NERC Category C contingencies, the temporary acceptable voltage range is 90 percent to 110 percent of the system nominal voltage. Exceptions for certain interconnected entities are evaluated accordingly. Methods of restoration to normal voltage range may include supervisory control of the following: capacitor banks, LTC's, generating unit voltage regulation, generation redispatch, line switching or firm service curtailments. Minimal planned load shedding may also be used for voltage restoration. These voltage criteria should be met with the net generator reactive power limited to 95 percent of the applicable reactive power capability. For Category C contingencies, consideration may be given to operating procedures that are designed to shed a minimum amount of load.
(Applicable NERC Standard: TPL-003-0-R1)

D. Extreme disturbance conditions (NERC Category D)

1) The MRO/RFC Extreme Disturbance Criteria and NERC Category D criteria should be used to assess system performance. These criteria may include examining loss of all circuits on a right-of-way and loss of an entire substation, including generation at that substation. These criteria should be used to determine system vulnerabilities, but may not necessarily dictate that potential problems identified need to be remedied with system additions.
(Applicable NERC Standard: TPL-004-0-R1)

1.2 TRANSIENT AND DYNAMIC STABILITY PERFORMANCE ASSESSMENT

Transient and dynamic stability assessments of the planning horizon are generally performed by the Transmission Planning Department to assure adequate avoidance of loss of generator synchronism, prevention of system voltage collapse, and system reactive power resources within 20 seconds after a system disturbance.

The ATC Operations Department performs an operating horizon assessment taking into account operating horizon assumptions that may differ from the planning horizon assessment for certain three phase fault scenarios which are documented in certain ATC Transmission Operating Procedures (TOP). The operating procedures reference any special circumstances in the planning studies and assessments and apply real time risk methodologies as outlined in the TOP procedures. *(Note: There may be other potential OPS planning tasks that may interface with Transmission planning tasks).*

The transient and dynamic system stability performance criteria to be utilized by ATC for planning purposes shall include the following factors.

A. Large disturbance stability performance assessment

1) For generator transient stability, faults will be modeled on the high side bus at generating plants.
2) For generating units with actual “as built” or “field setting” dynamic data, add a 0.5 cycle margin to the expected clearing time (ECT) for dynamic contingency simulations. For generating units with assumed, typical, or proposed dynamic data, add a 1.0 cycle margin to the ECT for dynamic contingency simulations. The total clearing time (ECT + margin) must be equal to or less than the calculated critical clearing time (CCT) from the simulation.
3) Generator transient stability will be demonstrated for at least one key contingency for each applicable NERC Category B contingency. These contingencies will typically be sustained three-phase faults of a single generator, transmission line, or transmission transformer with normal fault clearing.
(Applicable NERC Standards: TPL-002-0-R1)
4) Generator transient stability will be demonstrated for at least one key contingency for each applicable NERC Category C contingency. These contingencies will typically be three-phase faults of single elements with prior outage of a generator, line or transformer with normal clearing; single line-to-ground faults on a transmission bus or breaker with normal clearing; single line-to-ground faults on two transmission lines on a common structure with normal clearing; or single line-to-ground faults on a single generator, transmission line, transmission transformer or transmission bus section with delayed clearing.
(Applicable NERC Standards: TPL-003-0-R1)
5) Generator transient stability will be evaluated for at least one key contingency for two types of NERC Category D contingencies. These contingencies are three-phase faults on a transmission line with delayed clearing (D2) and three-phase faults on a transmission transformer with delayed clearing (D3). This ATC criterion is more severe than NERC Category D criteria because it requires every generating unit to maintain transient stability for this condition.
(Applicable NERC Standards: TPL-004-0-R1)
6) Generator transient stability will be reviewed for any other NERC Category D contingencies that are judged to be potentially critical to transmission system adequacy and security.
(Applicable NERC Standards: TPL-004-0-R1)
7) Unacceptable system transient stability performance for NERC Category A, B, and C outages and for ATC’s more severe Category D2 and D3 outages includes the following conditions:

A. Angular stability assessment

a. Generating unit loses synchronism with the transmission system, unless it is deliberately islanded

b. Cascading tripping of transmission lines or uncontrolled loss of load

c. Poorly damped angular oscillations, as defined in **Section 1.2.B.2** below

B. Voltage stability assessment

a. Voltage recovery within 70 percent and 120 percent of nominal immediately following the clearing of a disturbance[i].

b. Voltage recovery within 80 percent and 120 percent of nominal for between 2.0 and 20 seconds following the clearing of a disturbance.

c. Voltage instability (collapse) at any time after a disturbance [100 percent constant current modeling for real power load and 100 percent constant impedance modeling for reactive power load may be used in areas where the steady state operating point is at least 10 percent away from the nose of the P-V curve, otherwise appropriate induction motor modeling should be used for the voltage stability assessment.]
(Applicable NERC Standard: TPL-001-0-R1, TPL-002-0-R1, TPL-003-0-R1, TPL-004-0-R1)

B. Small disturbance performance assessment

The small disturbance (e.g. switching) stability performance criteria to be utilized by ATC will include:

1) With all generating units at their prescribed base case (normally full) real power output, no unit will exhibit poorly damped angular oscillations [as defined below] or unacceptable power swings in response to a (non-fault) loss of a generator, transmission circuit, or transmission transformer.
(Applicable NERC Standard: TPL-002-0-R1)

2) With all generating units at their prescribed base case (normally full) real power output, no unit will exhibit poorly damped angular oscillations [as defined below] or unacceptable power swings in response to a (non-fault) loss of any two transmission circuits on a common structure.

Note: Poorly damped angular oscillations are ones that do not meet either of the following criteria:

1. The generator rotor angle peak-to-peak magnitude is within 1.0 degree or less at 20 seconds after the switching event.

2. The generator average damping ratio is 15.0 percent or greater at 20 seconds after the switching event. The average damping ratio = (d1+d2+d3+d4)/4 * 100 percent. d1 = p5-p4/p5, d2 = p4-p3/p4, d3 = p3-p2/p3, d4 = p2-p1/p2.

1.3 VOLTAGE FLICKER

The criteria for acceptable voltage flicker levels are defined by the requirements of regulatory entities in the states in which ATC owns and operates transmission facilities, IEEE recommended practices and requirements, and the judgment of ATC.

The following flicker level criteria are to be observed at minimum system strength with all transmission facilities in service. Minimum system strength shall be defined as the condition produced by the generation that is in service in 50 percent peak load case models, minus any generation that is:

1) Electrically close to the actual or proposed flicker-producing load
2) Could significantly affect flicker levels
3) Could reasonably be expected to be out of service under light system load conditions

Although the limits described below are not required to be met during transmission system outages, if these limits are exceeded under outage conditions, the flicker producing load must be operated in a manner that does not adversely affect other loads. Planned outages can be dealt with by coordinating transmission and flicker producing load outages. Because operating restrictions during unplanned outages may be severe, it would be prudent for the owner of the harmonic producing load to study the effect of known, critical, or long term outages before they occur, so that remedial actions or operating restrictions can be designed before an outage occurs. During outages, actual, rather than minimum normal, system strength should be considered.
All ATC buses are required to adhere to the following three criteria.

1) RELATIVE STEADY STATE VOLTAGE CHANGE *IS LIMITED TO 3 PERCENT OF THE NOMINAL VOLTAGE FOR INTACT SYSTEM CONDITION SIMULATIONS. THE RELATIVE STEADY STATE VOLTAGE CHANGE IS THE DIFFERENCE IN VOLTAGE BEFORE AND AFTER AN EVENT, SUCH AS CAPACITOR SWITCHING OR LARGE MOTOR STARTING. THESE EVENTS SHOULD OCCUR AT LEAST 10 MINUTES APART AND TAKE LESS THAN 0.2 SECONDS (12 CYCLES) TO GO FROM AN INITIAL TO A FINAL VOLTAGE LEVEL.*
2) *Single frequency flicker* is to be below the applicable flicker curves described in Table A.1 of IEEE 1453-2004 “Recommended Practice of Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems.” Single frequency flicker is created by voltage affecting events that occur at a regular

interval and superimpose a single frequency waveform between 0 and 30 Hz on the fundamental frequency 60 Hz voltage waveform. Depending on frequency (the human eye is most sensitive to frequencies in the 5 to10 Hz range) sub-synchronous frequencies with magnitudes from 0.5 percent to 3 percent can cause irritable flicker. ATC uses the flicker curve in IEEE Standard 141 (commonly referred to as “The Modified GE Flicker Curve”) to determine the acceptability of single frequency flicker.

3) *Multiple frequency flicker* is to be limited to a short term perception (Pst) of 0.8 and a long term perception (Plt) of 0.6. Pst and Plt are calculated using the calculation methods outlined in IEEE standard 1453-2004. These limits can be exceeded 1 percent of the time with a minimum assessment period of one week. Multiple frequency flicker has the same frequency range as single frequency flicker, but is more complex to analyze, especially when flicker magnitudes and frequencies change over time. Multiple frequency flicker is best analyzed using a flicker meter.

1.4 HARMONIC VOLTAGE DISTORTION

In general, it is the responsibility of ATC to meet harmonic voltage limits and the responsibility of the load customers to meet harmonic current limits. The level of harmonics acceptable on the ATC system is defined by state regulations, IEEE Standard 519-1992 (Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems) and the judgment of ATC. Usually, if harmonic current limits are met, then harmonic voltage limits will also be met.

The observance of harmonic limits should be verified whenever a harmonic related problem is discovered or a new harmonic producing load with a reasonable possibility of causing harmonic problems is connected to the ATC system. The following process is utilized by ATC when managing an existing harmonic-related problem or a new harmonic-producing load:

1) *Existing problems* - When a harmonic related problem is found on the ATC system, it is ATC’s responsibility to determine the source of the harmonics. If harmonic current limits are violated, the source of the harmonics will be required to decrease their harmonic currents to below the limits specified in the ATC Planning and Service Guide. If, after the harmonic current has been reduced to an acceptable level, the harmonic voltage is still causing a problem and above specified levels, it shall be the responsibility of ATC to bring the harmonic voltages within limits. If limits are not violated and there is still a harmonic related problem (an unlikely situation), it is the responsibility of the entity experiencing the problem to harden its equipment to the effect of harmonics or reduce the harmonics at their location. An existing violation of these harmonic limits that is not causing any problems does not necessarily require harmonic mitigation.

2) <u>*New harmonic producing loads*</u> - It is the responsibility of any customer wanting to connect a harmonic producing load to the ATC system to determine if the proposed load will violate the harmonic current limits and, if these limits are violated, to determine and implement steps necessary to reduce the harmonic currents to acceptable levels. If harmonic voltage limits are not met after harmonic current limits have been met, it is the responsibility of ATC to determine if the harmonic voltage distortion will cause any system problems and if they will, it is ATC's responsibility to develop and implement a plan to meet the harmonic voltage limits.

2. Other Planning Criteria

2.1 Transmission Planning Assessment Practices

American Transmission Company generally subscribes to the zone approach to transmission planning assessment using a multi-level planning concept. Diagrams of the planning zones for which regional plans have been developed by ATC are attached in response to Part 3 of this FERC Form 715 and show the existing transmission facilities, 100 kV and above, within ATC's transmission system.

The concept behind the zone approach to transmission planning is to develop plans that consider all of the needs, problems and developments within each zone and develop an overall plan for the zone (that is, a plan that emphasizes projects that serve multiple purposes or solve multiple problems within the zone). In addition, ATC's transmission planning philosophies incorporate the concept of multi-level transmission planning. When carrying out a comprehensive transmission planning process, consideration must be given not only to individual transmission needs, zone needs, and ATC-wide needs, but also to plans of other transmission providers. Solutions identified via planning activities within each level are vetted against those in adjacent levels until the most effective overall comprehensive plan is developed. ATC's planning process will continue to develop the first three levels (individual, zone, ATC-wide). ATC is participating with other transmission owners within and affected by the MISO territory in assessing regional needs.

ATC is employing the long-standing practice of using power flow analysis to identify needs and problems and to evaluate alternative mitigation measures. ATC identifies problems and needs by simulating non-simultaneous outages of each line, transformer, bus section, and generator. ATC does implement operating guides, such as opening lines and bus sections, to mitigate problems (overloads, low voltages, etc.) during extreme flow conditions.

ATC is also conducting dynamic stability analyses within each of its zones to assess the ability of its system to withstand power system disturbances. Many of these analyses have been or are being conducted in conjunction with proposed generation interconnections. Other independent analyses are being conducted to assess dynamic and/or voltage stability performance.

Further, ATC develops transmission projects to address the congestion issues in its footprint. ATC uses the PROMOD model to analyze congestion across the ATC footprint and develop projects that will relieve the congestion. ATC submitted to the Public Service Commission of Wisconsin the first economically justified project in MISO and an order was received in the first half of 2008.

As part of the Midwest Independent System Operator, Inc. (MISO), ATC is participating in the MISO Transmission Expansion Plan process. ATC participates actively in all portions of MISO's planning efforts, including numerous committees and task forces, in regional and economic study efforts and in development of the Midwest Transmission Expansion Plan (MTEP).

The MAIN organization ceased to exist at the end of 2005 and ATC became a member of the two subsequent regional reliability organizations, the Midwest Reliability Organization (MRO) and the Reliability*First* Corporation (RFC). ATC participates in regional transmission assessments conducted by the MRO Transmission Assessment Subcommittee (TAS), the RFC Transmission Performance Subcommittee (TPS), the MAPP Transmission Reliability Assessment Working Group (TRAWG), the ERAG Reliability Assessments and MISO Reliability Assessments.

In addition to the planning criteria, ATC considers a number of other factors in its transmission planning process. Following is a description of such factors.

2.2 Public/Stakeholder Input

ATC solicits public and other stakeholder input on the identification of ultimate solutions through its iterative planning process. Projects may be modified as potential solutions listed in this plan are further developed to address the specific needs identified by all stakeholders. The solutions selected to address the needs and limitations identified will reflect the input of transmission planning process stakeholders, including customers, state and local officials, the public, and coordination with other planning processes, to the extent possible.

Specific opportunities for public and stakeholder participation in the planning process are provided in accordance with ATC's tariff Attachment FF filed at the FERC in response to the portion of FERC's Order 890 calling for open, inclusive and transparent planning processes. The filing was made on December 7th to be effective February 7th. ATC is implementing the tariff provisions as we await FERC's order response. ATC's Attachment FF covers six separate planning processes and the opportunities stakeholders have to participate in the processes. The six planning processes include:

- Network adequacy planning
- Economic project planning
- Generation-transmission interconnections
- Transmission-distribution interconnections
- Transmission-transmission interconnections
- Transmission service requests.

Provisions include opportunities for stakeholders to provide input to the planning processes in terms of assumptions and projects, provide review of interim results and see final results.

2.3 Capacity Benefit Margin Criteria

Capacity Benefit Margin (CBM) is the amount of firm transmission transfer capability preserved to enable access by LSEs to generation from interconnected systems to meet generation reliability requirements, such as meeting firm load obligations during a capacity emergency. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

As in MISO planning studies, ATC planning studies (other than the flow based analysis required for Midwest ISO (MISO) transmission service studies) will not model CBM. CBM is instead accommodated by ensuring that zones have the necessary emergency import capability through Loss of Load Expectation (LOLE) studies performed by the Midwest ISO and governed by the obligations of the MISO Module E of Energy Markets Tariff (EMT). If a deficiency is identified, we will incorporate any resulting incremental import capability requirements into ATC's overall transmission expansion plan.

MISO performs annual LOLE studies to determine the installed planning reserve margin that would result in the Midwest ISO system experiencing one loss of load event every ten years on average. This equates to a yearly LOLE value of 0.1 days per year. This value is determined through analysis using the GE Multi-Area Reliability Simulation (MARS) software. PROMOD software is used to perform a security constrained economic dispatch analysis which determines congestion related zones which are used in the MARS modeling. This analysis occurs on an annual basis to determine the zones and planning reserve margin for the next planning year as well as two other analysis years in the ten-year horizon.

As part of the LOLE studies, MISO calculates the Generation Capability Import Requirement (GCIR) for each zone. An import level equal to the GCIR level for each zone is simulated, and the MW impacts on each defined flowgate are recorded. For each flowgate, the highest MW impact due to a GCIR import into a zone becomes the calculated CBM for that flowgate

Then, for each flowgate MISO compares the flowgate's calculated CBM to the Automatic Reserve Sharing (ARS) component of the Transmission Reserve Margin (TRM) for that same flowgate. Since the worst case loss of a single resource is already covered by the ARS component of TRM, this amount of capacity is not redundantly preserved as part of CBM. If the ARS component is greater than the calculated CBM, no CBM will be preserved on that flowgate. If the ARS component is less than the calculated CBM, the incremental amount of CBM that is needed above the ARS component will be preserved as CBM for that flowgate.

2.4 Transmission Reliability Margin Criteria

Transmission Reliability Margin (TRM) is the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure during changing system conditions, particularly during Reserve Sharing events such as the loss of a critical single unit. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

In the planning horizon, anytime beyond 48 hours, MISO uses reservations from other transmission providers and Balancing Authority generation merit orders to reduce uncertainty. MISO will apply a 2 percent reduction in normal and emergency ratings for input uncertainties in the planning horizon. This is often referred to as the uncertainty component of the TRM.

The Automatic Reserve Sharing (ARS) component of TRM is the amount of transmission transfer capability required on a flowgate to deliver the amount of regional operating reserves associated with 100 percent of the greatest single contingency impacting the flowgate. To determine the ARS portion of TRM, MISO performs analyses to identify the required reserve for each flowgate. The worst single contingency is determined by tripping units (or transmission elements) within the region and replacing the lost resource with a realistic dispatch for each reserve sharing member's share of the emergency energy. The worst case is the case that has the greatest incremental flow over the flowgate in the direction of the constraint. The highest incremental flow on the flowgate for the contingencies evaluated (generation and transmission) will be the amount of ARS TRM required.

All MISO transmission service studies use the summation of ARS TRM and the 2 percent uncertainty TRM in the flow based analysis of transmission service studies. The network analysis for transmission service studies does not use the ARS or 2 percent TRM, but requires for all network elements a 3 percent reduction in normal and emergency ratings for requests in the next 13 months and a 5 percent reduction in normal and emergency ratings for requests extending beyond the next 13 months.

Other ATC planning studies utilize a 3 percent reduction in normal and emergency ratings for assessments within one year and a 5 percent reduction for the assessments beyond one year in the future. However, the recommended timing of the resultant mitigation measures may be based on less than the 3 percent and 5 percent reductions.

2.5 Facility Rating Criteria

The following ATC Operating Instructions provide documentation of ATC's facility ratings criteria:

- PR-0285 Facility Ratings Update and Application,
- CR-0061 Conductor Ampacity Ratings for Overhead Transmission Lines,
- CR-0063 Substation Equipment Ampacity Ratings,
- CR-0062 Ampacity Ratings of Underground Transmission Lines

We will actively review, replace, and document legacy ratings with ratings based upon ATC criteria in our Substation Equipment and Line Database (SELD). The legacy ratings from the previous transmission facilities owner's planning and operations models will be used in ATC planning models until valid SELD ratings, which are consistent with ATC facility rating criteria become available. The facility ratings criteria for legacy ratings are those of the corresponding contributing utility (e.g. Alliant East, Madison Gas & Electric, Upper Peninsula Power, Wisconsin Public Service, and We Energies). The ATC facility ratings criteria are consistently applied among ATC Planning, Engineering and Operations.

Facilities to be considered include, but are not limited to – overhead line conductors, underground cable, bus conductors, transformers, autotransformers, circuit breakers, disconnect switches, series and shunt reactive elements, VAR compensators, current transformers, wave traps, jumpers, meters, and relays (both overcurrent/directional overcurrent/impedance settings and thermal limits). Ratings derived from the ATC facility rating criteria are to be consistent with the following NERC standard.
(Applicable NERC Standards: FAC-004-0-R1)

2.6 Model Building Criteria

We will strive to develop and maintain consistency in the powerflow models used for planning efforts and in assessing whether and under what conditions transmission service is available. The starting point for ATC powerflow models will be models contained in the NERC and Regional data banks. We will use load forecasts provided by our end-use load-serving customers as input into future model building efforts, both internally and in conjunction with NERC, Regional Entity (RE), and Regional Transmission Operator (RTO) initiatives. These forecasts may be adjusted by ATC if adjustments are needed for transmission planning purposes either with concurrence from our customers or independently of our customers. All ATC powerflow models will be developed using PTI PSS/E software.
(Applicable NERC Standards: MOD-010-0-B, MOD-011-B, MOD-012-0-B)

Voltage Schedule

1) The powerflow models will implement ATC's standard generator voltage schedule of 102% of the nominal transmission voltage as measured at the point of interconnection between the generator and the transmission network unless another voltage schedule has been identified. ATC's desired generator voltage schedule bandwidth is 100% to 105% of the nominal transmission voltage and the maximum permissible bandwidth is 95% to 105% of nominal transmission voltage. Due to limitations imposed by the NERC model building process, the generator voltage schedules modeled in the NERC powerflow models may only approximate ATC's voltage schedule at the point of interconnection. (NERC VAR-001)
2) Generators that do not have automatic voltage regulation (AVR) or are not controllable (unmanned stations and no remote control) have been considered. When modeling these generators, special attention must be given to the limitations of these units.

Generation Dispatch

1) Generation within the boundaries of the ATC transmission system will be dispatched in accordance with contractual and local or regional economic dispatch considerations as applicable.
2) Designated Network Resources will be dispatched out of merit order if they have been identified as must run units.
3) Power-Voltage (P-V) analysis models wind generation at its full output level.
4) Generator Interconnection studies will model wind generation following the guidelines in the MISO Business Practice Manual for Generator Interconnections.

5) Generally, for each system load condition case, wind generation is modeled at 20% of its reported output level for general planning studies, although sensitivity analyses may dispatch wind generators at a higher output.

Net Scheduled Interchange

1) Net scheduled interchange for the ATC system will be coordinated with the necessary regional and interregional parties.
2) Net scheduled interchange for the ATC system may be altered to evaluate realistic system conditions of significance for system planning purposes.

2.7 Facility Condition Criteria

The facility condition criteria to be utilized by ATC for system planning purposes will include:

1) Any transmission line on structures that are beyond their design life, any transmission line that has exhibited below-average availability or any transmission line that has required above-average maintenance will be considered a candidate for replacement. In assessing potential line replacements, consideration will be given to other needs in the area of the candidate line to determine whether rebuilding the line to a higher voltage would fit into the "umbrella" plan for that planning zone (see Planning Zones below). ATC engineering, operation and maintenance and environmental employees work together to coordinate such assessments.
2) Any substation bus that is beyond its design life, has exhibited below-average availability, or has required above-average maintenance will be considered a candidate for rebuilding and potential redesign. In assessing potential bus rebuilds, consideration will be given to likely and potential expansion at candidate substations, including consideration of the "umbrella" plan for the planning zone. ATC engineering, operation and maintenance and environmental employees work together to coordinate such assessments.
3) Any substation whose design or configuration prevents maintenance in a safe manner on substation equipment or lines terminating at the substation will be considered a candidate for rebuilding and/or potential redesign/reconfiguration. In assessing such rebuilds/redesigns/reconfigurations, consideration will be given to likely and potential expansion at candidate substations, including consideration of the "umbrella" plan for the planning zone. ATC engineering, operation and maintenance and environmental employees work together to coordinate such assessments.
4) Any underground cable that is beyond its design life, has exhibited below-average availability, or has required above-average maintenance will be considered a candidate for replacement. In assessing potential cable replacements, consideration

will be given to other needs in the area of the candidate cable to determine whether replacing the cable with a cable with a higher ampacity or with a cable capable of a higher voltage would fit into the "umbrella" plan for that planning zone. ATC engineering, operation and maintenance and environmental employees work together to coordinate such assessments.

Planning Zones

We will conduct system planning on a long-range basis by developing plans for the ATC transmission system as a whole, as well as plans for specified **zones** within the boundaries of ATC's transmission system. The idea behind the zone approach to long-range planning is to develop plans that consider all of the needs/problems/developments within each zone. The goal within the ATC footprint is to develop an "umbrella" plan for each zone, that is, a plan that emphasizes projects that serve multiple purposes or solve multiple problems within the ATC system. The zone approach is intended to address requirements for support to the local distribution systems in that zone on a least cost basis. It is anticipated, however, that several projects that span more than one zone or possibly even the ATC transmission system boundaries may evolve. Such projects will likely involve coordination with other transmission owners or regional transmission organizations.

The planning zones deviate significantly from existing control area boundaries and from planning zones traditionally used for joint planning in conjunction with the Wisconsin PSC. The zones were selected considering the need for a manageable number of planning areas and to consolidate areas within the state with similar topology and load characteristics.

2.8 System Alternatives

We will consider alternatives to transmission solutions to problems on the transmission system as appropriate. Such alternatives could include, but are not limited to, central station generation, distributed generation, load management and conservation measures. We will use sound judgment in assessing whether non-transmission solutions are applicable on a case-by-case basis, keeping in mind that ATC is not a vertically integrated utility and does not own generation or serve as a load serving entity for retail load.

2.9 Load Forecasting Criteria

We will initially use load forecasts provided by our end-use load-serving customers. Such customers are required, under ATC's Distribution-Transmission Interconnection Agreements and Network Operating Agreements, to provide ATC with monthly peak demand forecasts for the next ten years. We may, in the future, develop load forecasts either concurrent with or independent of our load-serving customers. In addition, we may, in coordination with our load-serving customers, develop representative load duration curves based on actual and normalized load conditions. The ATC methodology for developing, aggregating and maintaining load forecast information should be in accordance with NERC Standard MOD-010-0-B and MOD-011-0-B.

In utilizing or developing load forecasts, the following criteria will be used:

1) **Summer peak** demand forecasts will be calculated in such a way that there is an almost equal probability of exceeding or falling short of the forecast when average peak making weather does occur.
2) **Winter peak** demand forecasts are assumed to be 80% of summer peak unless directed otherwise by the Load Distribution Company (LDC). Non-scalable loads remain unchanged.
3) **Summer shoulder peak** demand forecasts are assumed to be 70% of summer peak. Non-scalable loads remain unchanged.
4) **Fall/spring off-peak** demand forecasts are assumed to be 70% of summer peak unless directed otherwise by the LDC. Non-scalable loads remain unchanged.
5) **Summer 90/10 peak** demand forecasts will be developed that reflect above-average summer weather and peak demand conditions. This peak demand forecast will be calculated in such a way that there is a 90 percent probability of falling short of and a 10 percent probability of exceeding the forecast due to weather conditions. Until we develop the capability for producing a specific 90/10 forecast, we will assume that it can be reasonably approximated through increasing the summer peak conforming loads by 5 percent and leaving the non-scalable loads unchanged. The ratio of the real to reactive power of the loads will remain unchanged.
6) **Light load (50 percent of peak)** demand forecasts will be developed such that is the conforming loads are scaled to 50 percent of the summer peak demand forecasts. Non-scalable loads will remain unchanged.
7) **Minimum load (40 percent of peak)** demand forecasts will be developed such that the conforming loads are scaled to 40 percent of the summer peak demand forecasts. Non-scalable loads will remain unchanged.

2.10 Economic Criteria

We will conduct appropriate economic analyses when evaluating transmission additions, replacement and modifications. The criteria to be used in such economic analyses for purposes of system planning will include the following:

1) In developing screening level capital cost estimates for transmission lines and substations, terrain, geology and land use will be considered.
2) In conducting transmission system loss analysis, a sufficient number of powerflow cases will be developed to cover a reasonable range of load conditions from which to assess system losses. In addition, the value of losses shall be projected based on the energy futures market or on a credible energy price forecast.
3) In conducting analysis of generation redispatch precipitated by transmission constraints, a sufficient number of powerflow cases will be developed, or historical system loading may be used, in order to reasonably estimate the amount of time that such redispatch may be warranted. In addition, the cost of such redispatch will be projected based on marginal production costs and/or historical redispatch cost data of generating units dispatched to relieve the constraint. ATC will determine the economic feasibility of eliminating generation must-run situations based on these analyses.

All transmission projects have both reliability and economic impacts. In certain cases, economic benefits may be the primary driver of a project. In addition, economic analysis of projects may be used in the prioritization and staging of projects. In this effort, an attempt is made to capture all relevant factors in determining the economic benefits of a project. Stakeholder input is utilized by ATC for this purpose. Various tools are also utilized by ATC, including the Ventyx PROMOD software; however, other methods and tools are open to consideration.

2.11 Environmental Criteria

The overriding environmental criterion to be used by ATC in system planning is that environmental analyses will be conducted at a screening level as opposed to a detailed siting/routing analysis level. The goal of such environmental analyses is to identify potential environmental impacts, avoid such impacts where possible and, where it is not possible, minimize and mitigate such impacts to the extent possible. More detailed analyses will be undertaken to support an application to siting authorities of specific transmission alternatives.

2.12 Variations on ATC Planning Criteria

The ATC transmission system consists of assets contributed by entities within the five Balancing Authorities of the Wisconsin-Upper Michigan Systems. Each of the original asset owners planned their system to separate planning criteria, particularly in regard to transient and dynamic performance. Therefore, as ATC has implemented its own planning criteria, portions of the system may require upgrades to meet the more stringent ATC criteria.

This section of the ATC planning criteria describes the philosophy that will be followed for completing projects in a portion of the system identified as deficient with respect to the ATC criteria.

1) Area does not meet NERC Standards TPL-001, -002 or -003 with respect to stability.
   a. Complete projects required for bringing the existing system up to NERC Standards TPL-001, -002 or -003 performance requirements with no intentional delay.
   b. New generator interconnections are not permitted until the NERC standards are met with the addition of the generator, if the new generator interconnection aggravates the stability condition. [A new generation interconnection is deemed to aggravate the stability performance of an area if a change in scope is required to meet NERC Standards TPL-001, -002 or -003. See NERC Standard FAC-002 for new generator interconnections.]
   c. Depending on the level of risk associated with the deficiency, special operating procedures (restrictions or guides) may be required to mitigate the risk until the projects are completed. If a new generator interconnection is permitted but still negatively influences the stability condition, the operating restriction may follow a "last interconnected, first restricted" approach.
2) Area meets NERC Standards TPL-001, -002 or -003 but not ATC criteria with respect to stability.
   a. Normal schedule for projects required for bringing the existing system into compliance with ATC criteria.
   b. New generator interconnections are permitted as long as the system continues to meet the NERC Standards TPL-001, -002 or -003. If the new generator interconnection causes the system to be unable to meet the performance requirements of these NERC standards, 1.b above applies.
   c. Operating procedures will not be required in the interim period until the projects to meet ATC criteria are completed.
3) Area meets ATC planning criteria for existing system but a new generator interconnection causes a violation of:
   a. ATC planning criteria – New generator interconnection is not permitted until ATC criteria are met with the addition of the new generator.
   b. NERC Standards TPL-001, -002 or -003 under FAC-002 – New generator interconnection is not permitted until both NERC standards and ATC criteria are met.

2.13 Other Considerations

Project constructability

We will consider the constructability of proposed additions, replacements or modifications to the transmission system as part of our system planning process. In particular we will consider:

1) Whether addition, replacement or modification of a transmission line, transformer or other facility would result in violation of the **System performance criteria** above, and
2) Whether addition, replacement or modification of a transmission line, transformer or other facility precludes the ability of ATC Operations to conduct maintenance activities on other transmission facilities.

2.14 Multiple contingency planning

We will conduct system planning in accordance with the **System performance criteria** above, including planning for single contingency events. There may be circumstances, however, where the risk to ATC and/or ATC customers of a multiple contingency event is sufficiently severe to warrant consideration for planning purposes. Examples of such an event would include:

1) The loss of a transmission facility during the period of maintenance or repair of another transmission facility,
2) A multiple contingency arising from a common cause such as a fire, flood, etc., or
3) Failure of a transmission structure supporting multiple circuits.

We will evaluate the probability and consequences of certain selected multiple contingency scenarios to determine whether to apply a multiple contingency standard.

Such multiple contingency scenarios may warrant consideration of operating guides or reinforcements. In these circumstances, we will document the potential event(s), the associated risks and potential mitigation measures, and will coordinate with affected customers, as appropriate.
(Applicable NERC Standard: TPL-003-0-B, TPL-004-0-B)

Terminal equipment limitations

Substation terminal equipment should not limit transmission facility ratings under NERC Category A or NERC Category B contingency conditions. This criterion would apply to new transmission facilities and should be reviewed when proposing modifications to existing facilities.

Maximization of existing rights-of-way

We will attempt to maximize use of existing rights-of-ways. Existing electric transmission, gas pipeline, railroad and highway corridors will be identified in all comparisons of alternatives and utilized where feasible. Environmental features of a right of way are also important to our operations. Environmental assessments are built into planning at a high level, and are continued into project assessments as projects move forward through to construction. In addition to avoiding and protecting environmentally sensitive areas, ATC is committed to working in partnership with regulators, environmental organizations and landowners to enhance areas of environmental significance.

Since 2001, ATC has been an active partner in the Wisconsin karner blue butterfly partnership and manages rights of way in the karner blue butterfly range for host and nectar plants. ATC has also sponsored education and added management partnerships for this species. ATC is also recognized as a Green Tier company, with acceptance in October 2005. Green Tier is a program administered by the state of Wisconsin to recognize excellence in environmental performance. Through this program we continue to work closely with the Wisconsin Department of Natural resources to continually improve our environmental performance.

Reduction of transmission system losses

ATC considers the benefit of reducing system losses along with other performance benefits and cost factors in evaluations of alternative transmission projects or plans. See **Economic criteria**.

Transmission system operating considerations in the planning process

1) Operating procedures (operating guides)
   a) Operating guides are not preferred under normal conditions, but may be employed by ATC and/or entities with generation and/or distribution facilities interconnected with the ATC transmission system to avoid transmission facility loadings in excess of normal ratings provided such procedures are practical for sustained periods, if they meet the following conditions:
      (i) Do not compromise personnel or public safety
      (ii) Do not degrade system reliability
      (iii) Do not result in a significant loss of equipment life or significant risk of damage to a transmission facility.
      (iv) Do not unduly burden any entity financially.

b) Supervisory switching capability is required to accomplish these operating procedures. Field switching will not be relied upon as a means to reduce facility loadings or to restore voltages to within acceptable levels.

c) ATC will strive to verify the efficacy of all operating guides that require on-site operations.

2) System Planning - ATC will strive to plan the transmission system such that operating flexibility is maximized. We will accomplish this by considering as wide a variety of scenarios as practical, including maintenance scenarios, when evaluating alternative transmission projects or plans.

Radial transmission service

We will evaluate the risk of serving customer load from radial facilities. Such evaluations will consider the amount of load being served, the capability of the underlying distribution system and the amount of time that service is likely to be interrupted for the loss/failure of the radial facility.

Relaxation criteria

At times it may be appropriate to consider a relaxation of ATC-specific criteria, as long as NERC and RRO standards are still satisfied. As system planners perform their work, they should evaluate when it may be appropriate to allow a relaxation of ATC-specific criteria. A decision to relax ATC-specific criteria should be made very carefully considering all of the issues involved (including - but not limited to – Electric Reliability Organization (ERO) and RE requirements and Federal Energy Regulatory Commission (FERC) directives related to transmission service requirements) and then only after performing a detailed assessment of the types and levels of risks involved in the decision. **Planners are not permitted to relax ATC-specific criteria on their own**. Instead, these situations should be identified and discussed with their manager for further evaluation. The final decision in this regard will be made by the Director – System Planning. If any decisions of this type are made, then these decisions will be documented and archived for future reference.

Interconnection studies

The following analyses and procedures should be performed for all new or modified interconnection facilities (generation, transmission, and end-user) to the ATC system to properly assess their reliability impact on the interconnected systems. For some analyses, a formal study report may be appropriate. For other analyses, a simple statement of assumptions and rationale may be sufficient.

Types of Analysis
The analyses are to include steady state, short-circuit, and dynamic assessments that include the requirements in TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0.

Compliance with Applicable Planning Criteria
The analyses and procedures are to comply with all applicable NERC, Regional Entity, and individual system planning criteria of the affected parties.

Coordination with Affected Entities
The results of the analyses will be jointly evaluated and coordinated by the affected entities.

Essential Documentation
All analyses should include the evaluation assumptions, system performance, alternatives considered, and any jointly coordinated recommendations.

Specific Study Methodologies
Generator Interconnection studies will follow the study guidelines as described in the MISO Business Practice Manual for Generator Interconnections.