Planning Criteria

This document describes ATC's system planning criteria to plan, design, build and operate its transmission system in a safe, reliable and economic manner to meet the needs of its customers while maintaining and exceeding compliance with NERC and environment standards. This criteria applies to the ATC transmission system operated at 69-kV and above.

This document may be revised from time to time in response to changes in industry standards, new system conditions, new technologies 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.

2012 10-Year Assessment
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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.

1.1 Steady State Assessments Overview

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

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

At a minimum, two of the first three load conditions or similar models 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 Section 9, Load Forecasting Criteria**.**

General application of the steady state cases:

1) **Summer peak** - Used to determine summer peak load serving and regional supply limitations, including voltage security assessments.
2) **Summer 90/10 proxy peak** – Used considering 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 proxy forecast will be used to help prioritize and stage projects but it will not necessarily be used as the sole reason to justify projects or required in service dates.
3) **Summer shoulder peak** – Used to evaluate contingencies where transmission equipment may be intentionally outaged (e.g. maintenance duration of more than 6 months) at intermediate load levels in addition to assessing system biases or high system imports into the ATC foot print.
4) **Winter peak** – Used to determine winter peak load serving limitations.

5) **Fall/spring off-peak** – Used to evaluate contingencies where transmission equipment may be intentionally outaged (e.g. maintenance duration more than 6 months) at intermediate load levels to identify seasonal regional transfer impacts.
6) **Light load** –Used to study the possibility of high voltages on the power system, impact of capacitor switching, and potential equipment overloads near base load power plants due to reduced local demand at light load levels. The light load case represents many more hours in the year than the minimum load model.
7) **Minimum load** – Used to review the expected voltage range at distribution interconnection points and for determination of adequate voltage control at minimum load levels. Typically the highest bus voltages will occur with an intact transmission system during minimum load conditions

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 for its assessments shall include:

1.1.1. Normal Intact Conditions (NERC Category A)

No transmission element (BES and 69-kV transmission circuits, transformers, 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-001-1, R1)*

1) The normal 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 (e.g., agreements implemented for NERC standard NUC-001-2). 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-001-1, R1)*
2) The steady state voltage as noted in section 1.1.5 below should be stable at all ATC buses for normal intact system configurations and for a reasonably broad range of forecasted system demands and associated generation dispatch conditions. *(Applicable NERC Standard: TPL-001-1, R1)*

1.1.2. 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.

2) 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 limitation that will occur if left unmitigated (e.g., clearance limitation may take several minutes whereas exceeding a relay trip setting may result in an essentially instantaneous trip).
(Applicable NERC Standard: TPL-002-1, R1)

3) Under applicable NERC Category B contingencies, the temporary acceptable voltage range is 90 percent to 110 percent of the system nominal voltage. 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 (e.g., agreements implemented for NERC standard NUC-001-2). 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.

4) System design should ensure that voltage levels outside of any 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 percent or above 110 percent 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 percent to 110 percent) within an acceptable timeframe. The acceptable timeframe will be situation dependent and may need to be reviewed with Asset Planning & Engineering.
(Applicable NERC Standard: TPL-002-1, R1)

5) The steady state voltage should be stable at all ATC buses for applicable NERC Category B contingencies for a reasonably broad range of forecasted system demands and associated generation dispatch conditions.
(Applicable NERC Standard: TPL-002-1, R1)

6) 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.

1.1.3. 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-003-1, 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, LTCs, 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-003-1, R1)

3) The steady state voltage should be stable at all ATC buses for applicable NERC Category C contingencies for a reasonably broad range of forecasted system demands and associated generation dispatch conditions.
(Applicable NERC Standard: TPL-003-1, R1)

1.1.4. 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 or 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-004-1, R1)

1.1.5. Steady State Voltage Stability

1) The steady state voltage operating point at all ATC buses should be at least 10 percent away from the nose of the bus P-V curve and above the applicable low voltage limit (Category A, B, or C) 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 reliability margin.
2) Steady state voltage stability assessments are performed on a selective basis using engineering judgment, when ATC bus voltages are found to be at or below the low voltage limit at multiple buses in a common geographic area when performing other steady state analyses over a broad range of forecasted system demands and associated generation dispatch conditions. Otherwise, acceptable steady state voltage stability is assumed to exist.
3) System design should ensure that exceeding any steady state voltage IROL can be mitigated within 30 minutes. Temporary excursions above the applicable voltage stability limit are acceptable if a Special Protection System (SPS) will automatically (i.e. no manual intervention) return the system to an acceptable stability condition in an acceptable timeframe.

1.2 Dynamic Stability Assessments Overview

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:

1) **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.

2) **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.

1.2.1 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.

1.2.2 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-002-1, 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-003-1, 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 due to breaker failure (D2) and three-phase faults on a transmission transformer with delayed clearing due to breaker failure (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-004-1, 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-004-1, R1)

7) Unacceptable system transient stability performance for NERC Category B and C outages and for ATC's more severe Category D2 and D3 outages includes the conditions described below. Unacceptable system transient stability performance occurs when any of the following stability assessment criteria are not met. Corrective plans may include system reinforcements or establishing appropriate System Operating Limits (SOL) or Interconnected Reliability Operating Limits (IROL). Where needed system reinforcement cannot be implemented in an appropriate timeframe, then an SOL or IROL must be established.

A. Angular Stability Assessment

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

ii. Cascading tripping of transmission lines, tripping of transmission transformers or uncontrolled loss of load

iii. Poorly damped angular oscillations where acceptable damping is defined in Section 1.2.3 below

B. Voltage Stability Assessment

i. Voltage recovery within 70 percent and 120 percent of nominal immediately following the clearing of a disturbance[1].

[1] Motor terminal voltage recommendations from Carson Taylor paper

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

a. 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-002-1, R1, TPL-003-1, R1)

1.2.3 Small Disturbance Performance Assessment

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

1) Unacceptable small disturbance performance consists of a response beyond the limits described below. Unacceptable small disturbance performance indicates that a System Operating Limit (SOL) or an Interconnected Reliability Operating Limit (IROL) exists for the Planning Horizon where improvements cannot be implemented in an appropriate timeframe.

2) With all generating units at their prescribed base case (normally full) real power output, all units will exhibit well damped angular oscillations [as defined below] and acceptable power swings in response to a (non-fault) loss of a generator, transmission circuit, or transmission transformer.

   (Applicable NERC Standard: TPL-002-1, R1)

3) With all generating units at their prescribed base case (normally full) real power output, all units will exhibit well damped angular oscillations [as defined below] and acceptable power swings in response to a (non-fault) loss of any two transmission circuits on a common structure.

Note: Well damped angular oscillations need to meet one of the following two 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 factor for the last five cycles of the 20 second simulation is 15.0 percent or greater after the switching event.

Average Damping Factor (%) = $\left(\frac{d_1 + d_2 + d_3 + d_4}{4}\right) \times 100$

Where

$d_n = (1 - SPPR_n)$ where $SPPR_n$ (Successive Positive Peak Ratio) is the ratio of the peak-to-peak amplitude of a rotor angle swing (n_{th} cycle back from the 20 second simulation time) to the peak-to-peak amplitude of a rotor angle swing on the previous cycle ($n+1_{th}$ cycle back from the 20 second simulation time).

$$d_4 = 1 - \frac{p_4}{p_5},\ d_3 = 1 - \frac{p_3}{p_4},\ d_2 = 1 - \frac{p_2}{p_3},\ d_1 = 1 - \frac{p_1}{p_2}$$

Example

Last 5 peak-peak magnitudes:

1) max = 96.580 time = 9.654
min = 87.661 time = 10.712
peak-peak = 8.918

2) max = 94.526 time = 11.771
min = 89.222 time = 12.829
peak-peak = 5.304

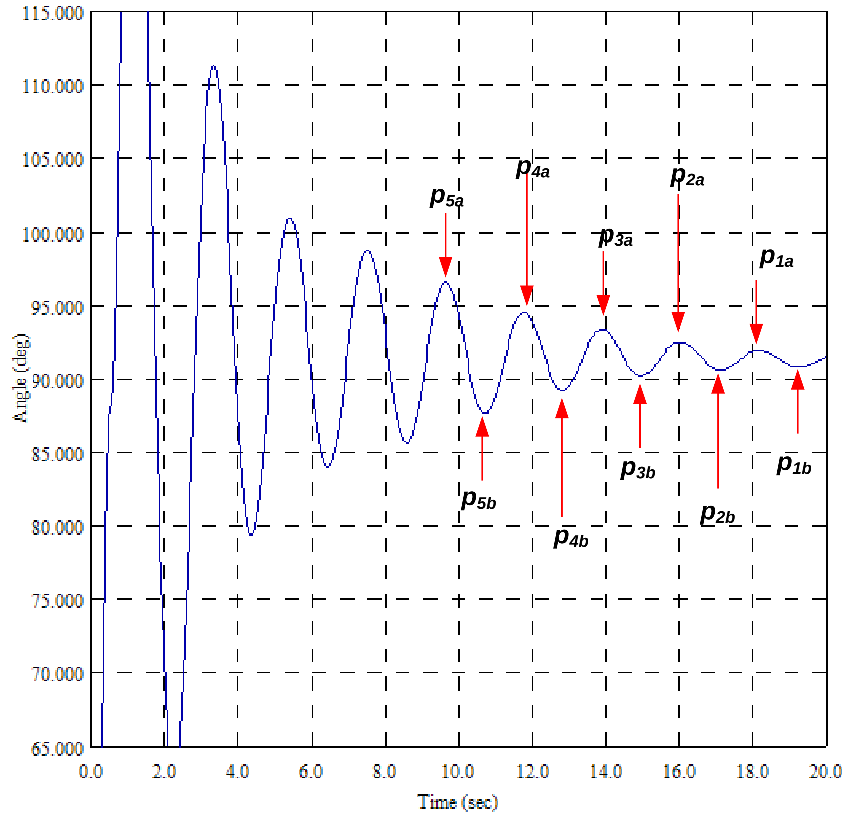
3) max = 93.371 time = 13.904
min = 90.226 time = 14.962
peak-peak = 3.146

4) max = 92.512 time = 16.021
min = 90.611 time = 17.113
peak-peak = 1.901

5) max = 91.941 time = 18.163
min = 90.811 time = 19.246
peak-peak = 1.129

Average Damping (last 5 peak-peak):
40.347 %

Ave. Freq. Oscillation (last 5 peak-peak):
0.470 Hz



$p_1 = p_{1a} - p_{1b} = 1.129$

$p_2 = p_{2a} - p_{2b} = 1.901$

$p_3 = p_{3a} - p_{3b} = 3.146$

$p_4 = p_{4a} - p_{4b} = 5.304$

$p_5 = p_{5a} - p_{5b} = 8.918$

$d_1 = 1 - (1.129/1.901) = 0.406102$

$d_2 = 1 - (1.901/3.146) = 0.395741$

$d_3 = 1 - (3.146/5.304) = 0.406863$

$d_4 = 1 - (5.304/8.918) = 0.405248$

Average Damping Ratio = ($d_1+d_2+d_3+d_4$) x 100 / 4 = 40.35%

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 criteria are described below.

The following flicker level criteria are to be observed at minimum nominal system strength with all transmission facilities in service. Minimum nominal 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 flicker 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 nominal, system strength should be considered.

All ATC buses are required to adhere to the following three criteria.

1. Relative steady state voltage change is typically limited to 3 percent of the nominal voltage for intact system condition simulations. For new projects, it is also typically limited to 5 percent under outage conditions. The relative steady state voltage change is the difference in voltage before and after an event, such as capacitor switching, load 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 0.001 and 24 Hz on the fundamental frequency 60 Hz voltage waveform. Depending on frequency (the human eye is most sensitive to frequencies in the 5 to12 Hz range) sub-synchronous frequencies with magnitudes from 0.35 percent to 8 percent can cause irritable flicker. ATC uses the flicker curve in IEEE Standard 1453-2004 (Table A.1) 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 and Current 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. Usually, if harmonic current limits are met, then harmonic voltage limits will also be met. 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. The voltage distortion limits and current distortion limits are specified in the Tables 1-4 below

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. 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) *New harmonic producing loads* - 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.

Table 1 – IEEE 519 Voltage Distortion Limits

Bus Voltage at Point of Common Coupling	Individual Voltage Distortion (%)	Total Voltage Distortion (%)
69-kV and below	3.0%	5.0%
69.001-kV through 161-kV	1.5%	2.5%
161.001-kV and above	1.0%	1.5%

Note 1: These limits should be used as system design values for the "worst case" for normal operation (conditions lasting longer than one hour). For periods lasting less than one hour, these limits may be exceeded by 50%.
Note 2: High-voltage systems (>161-kV) can have up to 2% Total Voltage Distortion when caused by a HVDC terminal whose harmonics are attenuated by the time it is tapped by a user.

Table 2 – IEEE 519 Current Distortion Limits for General Systems with Nominal Voltages Between 120-V to 69-kV and All Power Generation Equipment Maximum Harmonic Current Distortion for Odd Harmonics (Percent of I_L)

I_{SC}/I_L	Individual Harmonic Order					
	< 11	11<=*h*<17	17<=*h*<23	23<=*h*<35	35<=*h*	TDD
<20	4.0%	2.0%	1.5%	0.6%	0.3%	5.0%
20<50	7.0%	3.5%	2.5%	1.0%	0.5%	8.0%
50<100	10.0%	4.5%	4.0%	1.5%	0.7%	12.0%
100<1000	12.0%	5.5%	5.0%	2.0%	1.0%	15.0%
>1000	15.0%	7.0%	6.0%	2.5%	1.4%	20.0%

I_{SC} = maximum short circuit current at PCC
I_L = maximum demand load current (fundamental frequency component) at PCC
Note 1: Even Harmonics are limited to 25% of the odd harmonic limits listed above.
Note 2: Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
Note 3: All power generation equipment is limited to the I_{SC}/I_L<20 limits listed in this table, regardless of actual I_{SC}/I_L.

Table 3 – IEEE 519 Current Distortion Limits for General Systems with Nominal Voltages Between 69.001-kV and 161-kV Maximum Harmonic Current Distortion for Odd Harmonics (Percent of I_L)

I_{SC}/I_L	Individual Harmonic Order					
	< 11	11<=*h*<17	17<=*h*<23	23<=*h*<35	35<=*h*	TDD
<20	2.0%	1.0%	0.75%	0.3%	0.15%	2.5%
20<50	3.5%	1.75%	1.25%	0.5%	0.25%	4.0%
50<100	5.0%	2.25%	2.0%	0.75%	0.35%	6.0%
100<1000	6.0%	2.75%	2.5%	1.0%	0.5%	7.5%
>1000	7.5%	3.5%	3.0%	1.25%	0.7%	10.0%

I_{SC} = maximum short circuit current at PCC
I_L = maximum demand load current (fundamental frequency component) at PCC
Note 1: Even Harmonics are limited to 25% of the odd harmonic limits listed above.
Note 2: Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
Note 3: All power generation equipment is limited to the I_{SC}/I_L<20 limits listed in this table, regardless of actual I_{SC}/I_L.

Table 4 – IEEE 519 Current Distortion Limits for General Systems with Nominal Voltages Above 161-kV

Maximum Harmonic Current Distortion for Odd Harmonics (Percent of I_L)

I_{SC}/I_L	Individual Harmonic Order					
	< 11	11<=*h*<17	17<=*h*<23	23<=*h*<35	35<=*h*	TDD
<50	2.0%	1.0%	0.75%	0.3%	0.15%	2.5%
>50	3.0%	1.5%	1.15%	0.45%	0.22%	3.75%

I_{SC} = maximum short circuit current at PCC
I_L = maximum demand load current (fundamental frequency component) at PCC
Note 1: Even Harmonics are limited to 25% of the odd harmonic limits listed above.
Note 2: Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
Note 3: All power generation equipment is limited to the I_{SC}/I_L<50 limits listed in this table, regardless of actual I_{SC}/I_L.

2. 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 Midwest Independent Transmission System Operator (MISO) planning studies, ATC planning studies (other than the flow based analysis required for 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 M 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 MISO 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 Reliability 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.

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3. 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 contingency reserves. These contingency reserves are defined as 100 percent of the greatest single contingency impacting the 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 across the flowgate. The highest incremental flow on the flowgate for the contingencies evaluated (generation and transmission) will be the amount of ARS TRM required.

MISO uses the summation of the ARS and 2 percent uncertainty components of TRM in the network analysis for Long-Term Transmission Service Requests. Please reference the MISO TRMID for a description of the application of TRM to all Transmission Service Requests.
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, except for studies that consider a wide range of system conditions (e.g., load, dispatch, transfers), such as 10-year assessments. The recommended timing of the resultant mitigation measures may be based on less than the 3 percent and 5 percent reductions.

4. FACILITY RATING CRITERIA

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

1) PR-0285 Facility Ratings Update and Application,
2) CR-0061 Conductor Ampacity Ratings for Overhead Transmission Lines,
3) CR-0063 Substation Equipment Ampacity Ratings,
4) 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-008-1-R1)

5. MODEL BUILDING CRITERIA

We will strive to develop and maintain consistency in the power flow models used for planning efforts and in assessing whether and under what conditions transmission service is available. The starting point for ATC power flow 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 power flow models will be developed using PTI PSS/E software.
(Applicable NERC Standards: MOD-010-0, MOD-011, MOD-012-0)

5.1. Voltage Schedule

1) The power flow models will implement ATC's generator voltage schedule. The generator voltage schedule is defined as a:
    a. Target voltage 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 and,
    b. Normal voltage range of 95% to 105% of nominal transmission voltage.

    Due to limitations imposed by the NERC model building process, the generator voltage schedule target modeled in the NERC power flow 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.

5.2. Generation Dispatch

1) Generation reported by ATC's members 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 percent of its reported output level for general planning studies, although sensitivity analyses may dispatch wind generators at various output levels.

5.3. 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.

6. 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.

7. 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.

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.

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 will follow the NERC Standards MOD-010-0 and MOD-011-0.

In utilizing or developing load forecasts, the following methodology 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) **Shoulder peak** demand forecasts will be developed such that the scalable loads are scaled to a pre-calculated percent of the Summer peak demand forecasts while holding the non-scalable loads smaller than or equal to 5 MW constant and applying shoulder load ratios[2] for the non-scalable loads greater than 5 MW. The resultant overall ATC load in the Shoulder peak model is ~70 percent of the Summer peak. The ratio of the real to reactive power of the loads will remain unchanged.
3) **Winter peak** demand forecasts will be developed such that the scalable loads are scaled to Local Distribution Company (LDC) chosen percentages for the month of

[2] To enhance the modeling of shoulder and light load conditions for the ATC Planning analysis, during the load forecast process, ATC requested local distribution companies to provide shoulder-to-peak ratios and light-to-peak ratios for the non-scalable loads greater than 5 MW.

January. Non-scalable loads remain unchanged. The ratio of the real to reactive power of the loads will remain unchanged.

4) **Fall/spring off-peak** demand forecasts will be developed such that the scalable loads are scaled to LDC chosen percentages for the month of November for fall or the month of April for spring. Non-scalable loads smaller than or equal to 5 MW remain unchanged while applying shoulder load ratios[2] for the non-scalable loads greater than 5 MW. The ratio of the real to reactive power of the loads will remain unchanged.

5) **Summer 90/10 proxy peak** demand forecasts will be developed that reflect above-average summer weather and peak demand conditions. A true summer 90/10 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 load forecast by about 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 the conforming loads are scaled to a pre-calculated percent of the Summer peak demand forecasts while holding the non-scalable loads smaller than or equal to 5 MW constant and applying light load ratios[2] for the non-scalable loads greater than 5 MW. The resultant overall ATC load in the Light load model is ~50% of the Summer peak. The ratio of the real to reactive power of the loads will remain unchanged.

7) **Minimum load (40 percent of peak)** demand forecasts will be developed such that the conforming loads are scaled to a pre-calculated percent of the Summer peak demand forecasts, while holding the non-scalable loads smaller than or equal to 5 MW constant and applying light load ratios[2] for the non-scalable loads greater than 5 MW. The resultant overall ATC load in the Minimum load model is ~40% of the Summer peak. The ratio of the real to reactive power of the loads will remain unchanged.

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 the economic analysis of changes in transmission system losses, hourly line flow data and associated area Locational Marginal Prices (LMPs) for the entire analysis year from PROMOD will be used to analyze the potential savings

from reduced transmission line losses associated with a new project (or package of projects).

3) The reduction in the need to build additional generation to serve the peak load will be calculated by comparing the losses from the power flows for the peak load hour with and without the project. To correctly do the accounting, the reduction in the generation needed to serve the peak load will be increased by the Midwest ISO's planning reserve margin. The dollar value of this savings will be based on the construction cost of a combustion turbine.

4) The LMP market simulation tool, PROMOD, will be the primary tool used to analyze the economics of projects. ATC's Customer Benefit Metric will typically be used to analyze the market savings of projects. Generally PROMOD will be run with and without the project, or package of projects, to determine the market savings. Other economic benefits may also be calculated, such as the "insurance benefit" associated with having a more robust transmission grid to respond to low probability, but high impact transmission and generation outages, which can cause market prices and costs to spike.

5) 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.

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.

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-001-1, -002-1 or -003-1 with respect to stability.
   a. Complete projects required for bringing the existing system up to NERC Standards TPL-001-1, -002-1 or -003-1 performance requirements with no intentional delay.
   b. New generator interconnections are <u>not</u> 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-001-1, -002-1 or -003-1. See NERC Standard FAC-002-1 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-001-1, -002-1 or -003-1 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-001-1, -002-1 or -003-1. 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-001-1, -002-1 or -003-1 under FAC-002-1 – New generator interconnection is not permitted until both NERC standards and ATC criteria are met.

13. OTHER CONSIDERATIONS

13.1. 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.

13.2. Multiple contingency planning

. 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 and/or,
2) A multiple contingency arising from a common cause such as a fire, flood, lightning etc., and/or
3) Failure of a transmission structure supporting multiple circuits.

We will consider the relative 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-003-1, TPL-004-1)

13.3. 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.

13.4. 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.

13.5. 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.

<u>Transmission system operating considerations in the planning process</u>

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.

13.6. 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.

13.7. Relaxation of 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.

14. 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.

1) Types of Analysis

The analyses are to include steady state, short-circuit, and dynamic assessments that include the requirements in TPL-001-1, TPL-002-1, TPL-003-1, and TPL-004-1.

2) 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.

3) Coordination with Affected Entities

The results of the analyses will be jointly evaluated and coordinated by the affected entities.

4) Essential Documentation

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

5) Specific Study Methodologies

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

15. REFERENCES

None.