Planning considerations
In evaluating the transmission system and planning for what will be needed in the future, we consider a number of variables such as:

- *At what rate will electricity demand increase in the future? What kind of electricity uses will drive the increases in demand?*
- *What generation is likely to be constructed; what is likely to be retired?*
- *What types of disturbances on the transmission system are particularly serious or problematic?*
- *What existing facilities need to be replaced based on their age or condition?*
- *How can improved access to low-cost power outside of Wisconsin and Michigan's Upper Peninsula best be achieved? Which chronic constraints need to be addressed?*
- *How can improving access between in-state utilities best be achieved? Which chronic constraints need to be addressed?*
- *How much will it cost to provide reliable transmission service and improve access?*
- *What are the benefits associated with transmission system expansion plans and how can they be measured?*
- *What are the social and environmental impacts of our transmission system expansion plans?*
- *What new, proven technologies may be available to help meet the needs more effectively and efficiently?*

These are some key considerations that we take into account, but there are numerous other objectives including improving system efficiency, providing economic development opportunities and helping our customers remain competitive in the future. Throughout this 10-Year Assessment, we are striving to address the issues and questions above to develop the most beneficial and cost-effective expansion plan possible.

1. Transmission system expansion drivers
There are numerous factors that can drive the need for transmission system expansion. In some cases, more than one factor will signal the need for system expansion. The most common expansion drivers are described below and include:

- Electric load growth
- Transmission-distribution interconnections
- Transmission service limitations
- New generation
- Transmission service requests
- System repair or replacement
- Regional needs
- Economic strategic expansion

- **Electric load growth** – The load growth driver in this Assessment is slightly lower than in the previous Assessment. Demand for electricity during peak load periods is projected to grow at a rate of 1.4 percent across our service territory from 2010 through 2020. However, load growth rates in some areas are projected to grow by as much as 8 percent, while no growth is projected in other areas. Not surprisingly, many areas of high load growth correspond to areas where we are proposing system enhancements and/or expansion.

  Figure PF-1 shows the projected growth in peak demand, in MW, from 2010 through 2020 for various areas of our system. Note that most of the high growth (greater than 20 MW) is in the metropolitan Milwaukee, Madison and Fox Valley areas. While these higher-growth areas may require system expansion, there is considerably more existing transmission infrastructure in these areas. Of equal or greater concern is high growth in areas where there is much less existing transmission infrastructure because the capacity of the existing system may be reaching its limits, perhaps requiring additional infrastructure.

  Figure PF-2 shows the projected rates of growth on our system. This is perhaps more revealing as it shows what areas are experiencing high rates of growth, regardless of the magnitude of load that exists today. Certain areas of our system have more transmission infrastructure today and are not as likely to need infrastructure additions to support expected load growth. Note that the high rates of growth in and around Madison, Lake Geneva, Green Bay, Rhinelander, Wis., and Marquette, Mich. were not depicted as being among the highest MW growth areas in Figure PF-1. These areas of high growth rates actually are better indicators of when and where system expansion is likely to be needed.

Many of the line or transformer overloads or low voltages during peak load are due to electric load growth. System expansion is required to ensure that the transmission system can operate reliably – mitigating overloads and low voltages.

- **Transmission-distribution interconnections** – A natural extension of load growth is the need for additional transmission-distribution interconnections (TDIs). As the capacity of the transmission system gets more fully utilized when load growth occurs, similarly this often happens on the distribution systems as well, requiring new interconnections to the transmission system.

  In most cases, distribution companies will attempt to unload existing distribution facilities by siting a new TDI near an existing transmission line and redistributing some of the load in the area to the new TDI. In some instances, however, it makes more sense to construct transmission closer to where the load growth is occurring.

  A list of all of the planned TDIs on ATC's system can be found at: *http://www.atcllc.com/oasis/liqueue.xls.* Please refer to our Transmission-Distribution Interconnections section for more information.

- **New generation –** When entities plan to construct new generating facilities, there are two key considerations from the transmission owner's perspective:
  - Can the proposed generating facilities be interconnected and remain stable during system disturbances, and will nearby generating facilities remain stable?
  - Can the electricity produced by the generating facilities be delivered reliably to the ultimate customer(s)?

  For each entity that plans to construct a new generating facility, the transmission provider will conduct an interconnection study. If the existing transmission system is inadequate to ensure generator stability or reliable transmission service, the transmission provider will determine what system expansion will be needed.

  We have constructed and are in the process of planning and/or constructing transmission facilities that are needed to interconnect and/or provide transmission service from new generators. The transmission facilities being planned or constructed to accommodate new generation can be found in Tables PR-2 through PR-23**.** In the Need Category column, look for "new generation." Also, see Generation interconnections.

- **Transmission service requests –** In the Midwest Independent System Operator, Inc. (MISO) Day 2 Market, transmission services requests are used less but still are an available option. Power plant owners and local distribution companies can transact with other entities to buy and sell electricity. Power plant owners with surplus generating capacity may attempt to sell that surplus capacity. Entities serving end-use customers may attempt to lower their costs by accessing and purchasing low-cost electricity. In addition to the Day 2 Market another way in which these entities gain access to the transmission system to make these transactions is by making transmission service requests. Transmission service providers, or transmission owners like ATC, evaluate those requests to determine whether the transmission system can be operated reliably if the request is granted. If the request can't be granted, the transmission service provider may determine how the transmission system needs to be expanded to grant the request. The types of requests that would require some sort of system expansion are longer-term requests (transactions lasting longer than one year) and which start at some point in time in the future. Requests for service in the near future may have to simply be denied because system expansion facilities can't be constructed in time.

We have constructed and are in the process of planning and/or constructing, transmission facilities that are required to grant transmission service requests. The transmission facilities being planned or constructed to meet transmission service requests can be found in Tables PR-2 through PR-23**.** In the Need Category column, look for "service limitation."

- **System repair or replacement** – Many components of our transmission system will need to be repaired or replaced in the coming years due to condition or obsolescence. In some cases, the need to reconstruct a transmission line may provide opportunities to increase the capacity of those components and improve reliability. Facilities being planned or constructed to address condition or obsolescence issues can be found in Tables PR-2 through PR-23. In the Need Category column, look for "condition." Please also refer to Tables AR-1 through AR-3 for a listing of our asset renewal projects.

- **Regional needs** - Our transmission system is interconnected directly with neighboring systems and is operated in conjunction with all transmission systems within MISO and ultimately the eastern interconnection. Because these transmission systems work together and not independently, regional planning to identify and plan for needs at a regional level is necessary.

  ATC provides its system plan to MISO for coordination within MISO's regional plan, known as MISO's Transmission Expansion Plan (MTEP). ATC and MISO collaborate to facilitate MISO's review of the projects. MISO reviews the transmission projects and alternatives where applicable, submitted by ATC to verify the reliability or economic needs, to ensure they do not have an adverse affect over the MISO footprint and to determine if they could be combined in conjunction with transmission projects from other transmission owners to develop the most cost-effective alternatives.

ATC also participates in regional studies that investigate transmission needs across footprints of multiple transmission owners. For example, ATC participates in regional studies coordinated by MISO such as the Regional Generation Outlet Study (RGOS) that investigates transmission plans to integrate wind generation that supports the MISO state Renewable Portfolio Standard (RPS) requirements and beyond. ATC also meets with adjacent transmission owners to coordinate planning in an effort to develop transmission solutions that resolve reliability issues that impact multiple transmission owners at the lowest reasonable cost. Please refer to the Regional Analyses section for more information on ATC's participation in regional planning activities.

- **Economic/strategic system expansion –** In the electric utility industry, change has become more of the norm rather than the exception. For example, in recent years, wholesale electricity markets have continued to evolve, renewable generation has gained a larger market share, and the generation market, in general, has become more competitive. In addition, because both residential and business customers are more mobile, migration of electric customers to other areas is a greater risk consideration for utilities. In order for utilities to remain cost competitive and compliant, they must have the flexibility to take advantage of trends that have the potential to lower costs and to comply with renewable portfolio requirements. To the extent that low-cost generation development is occurring in an adjacent state, it may make sense for a transmission provider to construct transmission facilities that would allow its utility customers better access to that low-cost generation.

  Along these lines, we have been investigating ways to take advantage of certain potential developments in the electricity industry to give its customers more ways to lower costs. The primary outgrowth of this effort is outlined further in our Economic Planning section.

2. Customer needs

Our customers provide us with input on their needs and suggestions about areas on which we should focus. Some of the most prevalent issues are described below.

- **Improved access –** Virtually all of our customers have indicated a desire to have better transmission access to out-of-state markets as well as fewer constraints in transacting with their neighboring utilities within the ATC footprint. In response, we launched an Economic Planning Initiative, taking a comprehensive look at the technical feasibility and economic impacts of constructing new transmission lines within ATC and/or to neighboring states.

- **Transmission-distribution interconnection process** – In response to the relatively large number of proposed T-D interconnections, we have developed a process that provides guidelines for our joint Best Value Planning (BVP) efforts. Four BVP levels have been identified to help ATC and its customers identify the appropriate effort to develop potential interconnections. BVP levels are determined based on the assumed scope of work for ATC according to the most likely option for interconnecting the customer facility(ies). A level one BVP assumes that ATC has virtually no capital costs to interconnect the customer. A level four BVP assumes that ATC has to develop a project that requires PSCW regulatory approval (CA or CPCN). Please refer to ATC's D-T Interconnection Business Practice for details.

- **Control of transmission construction costs –** Our customers desire reliable access to the transmission system as cost-effectively as possible. To accomplish this, ATC has partnered with the industry's leading design, construction, and materials sourcing companies. Our partners' expertise helps ATC maintain and construct transmission system assets with a focus on low long-term costs. Also, our recent addition of a Project Controls Office ensures that we are continually reviewing projects for cost-saving opportunities.

- **Integration of transmission and generation planning –** Our transmission system does not have significant transmission capacity beyond current network needs. As a consequence, generation interconnections cannot be effectively pre-analyzed on a generic basis. Further complicating the issue, construction of generation facilities can occur through regulated or unregulated entities, subject to varying levels of state regulatory requirements. Federal regulations require that we be responsive to all requests for generation interconnection in a consistent and non-discriminatory manner.

  We continue to explore potential methods to allow more effective integration of generation and transmission planning in a way that recognizes the limitations of generic analysis and is consistent with federal regulatory obligations. In addition, we continue to work concurrently with our customers to balance market-sensitive long-range plans, confidential market-sensitive information, and the desire to better integrate these plans.

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) _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.

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 7^{th} to be effective February 7^{th}. 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.

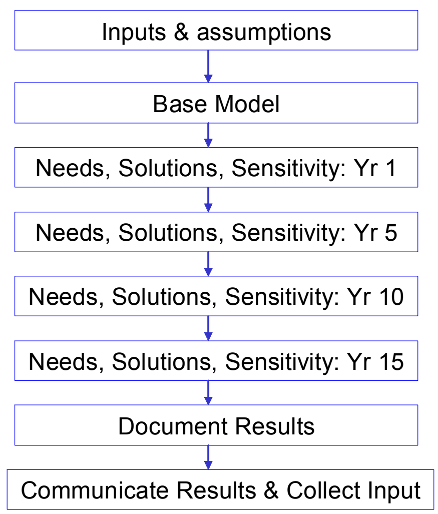
Methodology & assumptions

1.1 Overview

This section describes the methods and techniques that we use to analyze our network transmission system for this assessment. Economic, regional, environmental and asset management planning processes are covered on other sections of this Web site.

As part of the network assessment, ATC conducted power flow analyses to identify problems or constraints on the transmission system and evaluated the merits of potential reinforcements to address the system limitations that were identified. Once these analyses are complete, ATC meets with our stakeholders to discuss the preliminary results.

ATC's network planning process is summarized in the below figure:



Included in this section is a discussion of which years ATC identified to model to satisfy both the near-term (1 – 5 year horizon) and long-term (5 year and beyond horizon) NERC standards for assessing the transmission system. Also included in this section is discussion on how ATC built each of the models used in this assessment. Discussion items include topics such as load forecasting, which reinforcements and new generation to include in models, which system load levels, import levels and system bias scenarios to evaluate.

During the network assessment of our transmission system, we performed simulations on a variety of models as discussed below in this section. ATC not only uses these models to identify where constraints or system limitations may exist, but we also use these models in testing the robustness of potential system reinforcements. Per our Planning criteria, constraints or system limitations are identified for NERC Category A type system conditions when bus voltages drop below 95 percent or exceed 105 percent of their nominal voltage or when any system element exceeds it normal rating for the appropriate seasonal model. For NERC Category A or system intact conditions, ATC's Planning criteria also requires for generators to be limited to 90 percent of their net Q_{max} capability within ATC footprint.

For NERC Category B, C or D contingencies, system limitations or constraints are identified using slightly different criterion. For these types of system contingency conditions, ATC's Planning Criteria identify system limitations when bus voltages drop below 90 percent or exceed 110 percent of their nominal voltage or when any system element exceeds its emergency rating for the appropriate seasonal model. For these three NERC categories, ATC's Planning criteria requires generators to be limited to 95 percent of their net Q_{max} capability within ATC footprint.

In all of the models, normal operating procedures were modeled for the applicable normal system conditions. All existing and planned protection systems, including any backup or redundant systems that would be applicable to a given contingency were simulated in the studies and analyses. All existing and planned control devices that would be applicable to a given contingency were simulated in the studies and analyses. These control devices include transformer automatic tap changers, capacitor bank automatic controls, and Distribution Superconducting Magnetic Energy Storage (DSMES) units. No specific facility outages are modeled in the planning horizon at the demand levels that were studied due to lack of future outage schedules. As the future unfolds and facility outages are scheduled, they will be timed for conditions that provide acceptable reliability.

The analyses conducted in this transmission system assessment included steady state power flow analyses, stability simulations, multiple outage impacts as well as economic evaluations, generator interconnection impacts, transmission-distribution interconnection impacts and environmental assessment impacts.

1.2 Network assessment methodology

American Transmission Co.'s 2010 10-Year Transmission System Assessment provides current results of planning activities and analyses of the company's transmission facilities. These activities and analyses identify needs for network transmission system enhancement and potential projects responsive to those needs.

Since 2001, we have engaged in open and collaborative efforts to share information and solicit input on our plans. We believe that in making our planning efforts transparent and available to the public, the proposals for needed facilities can be more readily understood and accepted by communities that stand to benefit from them. In recent years the federal government has taken additional steps to ensure that transmission-owning utilities have produced and shared planning information with the public and local stakeholders.

The information in this report provides further foundation for continued public discussions on the transmission planning process, identified transmission needs and limitations, possible resolutions to those needs and coordination with other public infrastructure planning processes.

Computer simulation model years for the 2010 network Assessment analyses were selected in order to meet NERC requirements for a 1-5 year horizon and beyond the 5 year horizon. The years 2011 and 2015 were selected to meet the 1-5 year horizon. The years 2020 and 2025 meet the beyond 5 year horizon. A range of system conditions and study years were developed and analyzed for the 2010 Assessment. Steady state peak load models for all four years were created. In order to determine how close ATC generators were to their maximum var output, two additional models were created for each year. The one model reduced ATC generator net Q_{max} by 10 percent for each year studied. These models were utilized to determine generator var output under intact system conditions (TPL-001-0). A second model for each year was created with net Q_{max} reduced by 5 percent. These models were used for our N-1 (TPL-002-0) analysis.

The needs identified in this Assessment were determined by identifying facilities whose normal or emergency ratings or tolerances are exceeded. The criterion we use to determine what these ratings and tolerances should be is provided in Planning criteria).

This 2010 network Assessment was developed in a chronological fashion. Planned transmission additions expected to be in service by June 2011 were included in the 2011 model, as listed in Table PF-1. Projects for which we have completed our analysis and are either under construction, have filed an application to construct, or are in the process of preparing an application were included in the 2015, 2020 and 2025 models as appropriate based on projected in service dates (See Tables PF-2, PF-3 and PF-4).

1.2.1 Load forecast

Steady state summer peak models are built using our customers' load forecasts (50/50 projections) as a starting point, meaning that there is a 50 percent chance that the load level will either fall below or exceed the customer projection. Customer load forecasts were gathered for all ATC customers through the year 2019 (and in some cases 2020/2025). The forecasts were compared to previous historical and forecasted data to ensure validity and consistency. As a final step, the finalized forecast information was forwarded back to our individual customers to ensure their concurrence. Once consensus was achieved, the data was incorporated into our models.

Certain ATC customers did not provide an 11th-year load forecast for the year 2020. To obtain a forecast for 2020, certain customer-provided forecasts were extended by growing their load by a fixed growth percentage based upon the previous 3-years' growth (approximately 1.3% compounded annually). Non-scalable loads were held at their 2019 levels using this methodology.

The 2025 summer peak load model was developed utilizing similar methodology. To obtain a projection for 2025, customer-provided forecasts were extended by growing their load by a fixed growth percentage based upon the previous 3-years' growth (approximately 1.3% compounded annually). Non-scalable loads were once again held at their 2019 (or 2020) load levels. It should be noted that the loads utilized in the 2025 summer peak model do not reflect an actual load forecast, but merely a projection (or "load model") based upon the best available information. The purpose for the 2025 projection is not to develop projects to address all issues, but to develop a sense for the need(s) for long lead-time projects.

ATC Peak Load Projections (MW) including line losses

Year	MW load	Compounded growth rate
2010	13,681	N/A
2011	14,099	N/A
2015	14,832	1.3% (2011-2015)
2020	15,879	1.4% (2015-2020)
2025	16,973*	1.3% (2020-2025)
Overall		1.4% (2010-2025)

**load model, not a load forecast*

It should be noted that we worked with the distribution companies as much as possible to confirm forecast variations from past trends. In a few cases we revised power factors to reasonable levels to prevent creating expensive transmission projects for voltage support. In most cases these issues would ultimately be solved through distribution system power factor correction. ATC will be in ongoing discussions with our customers to determine the best plan for these situations.

1.2.2 Model building
1.2.2.a Assumptions common to all models

1.2.2.a.1 New generation

There have been numerous generation projects proposed within ATC's service territory. Many of these proposed projects have interconnection studies completed and a few have had transmission service facility studies completed. Several have proceeded to or through the licensing phase and several more are under construction. However, there are numerous proposed generation projects that have dropped out of the generation queue (refer to Generation interconnections), adding considerable uncertainty to the transmission planning process. To address this planning uncertainty, we have adopted a criterion for purposes of this and prior Assessments, to establish which proposed generation projects would be included in the 2010 Assessment models.

Previously (before the advent of the MISO Day 2 market) the criterion was that those generation projects for which, at the time the models were developed,

1. *ATC had **completed** a generation interconnection impact study, a generation interconnection facility study, a transmission service impact study and a transmission service facility study, **and***
2. *the generation developer or a customer of the developer had **accepted** the transmission service approved by ATC.*

In the 2010 10-Year Assessment, the criterion was broken into two time frames, years 1 through 5 and 6+ years.

1. For years 1 through 5, only those generators with FERC approved interconnection agreements will be included in the planning models.
2. Beginning with year 6 and continuing into the future, generators are only required to have a Facility Study completed in order to be included in the 10-Year Assessment models.

A number of wind generators in the ATC footprint have suspended FERC approved interconnection agreements. For the first three years following their requested in-service dates, ATC criterion calls for modeling these facilities but dispatching them at the bottom of the dispatch order. After the three years, the generators will be dispatched in their normal dispatch order. The wind generators with suspended agreements were included in the models built for the 10-Year Assessment analysis. The 2010 and 2011 models showed these generators as out of service. The 2015 and 2020 models should have had these generators in-service and dispatched.

1.2.2.a.2 Generation retirements

On occasion, generators connected to the ATC transmission system are retired or mothballed. As a result, we developed criteria to determine when generators should no longer be included in our 10-Year Assessment models. If the generator has a completed MISO Attachment Y study, the generator will be disconnected in the appropriate load flow study models. In addition, ATC sent an annual letter to each generation owner. Generating companies were asked to identify generator retirements or mothballing that should be included in ATC’s planning horizon. Generators identified as such by the customer will be modeled off line in the relevant models.

There are generators that have been publicly announced as likely candidates for retirement. However, using the disconnection criteria above, in the 2010 10-Year Assessment models we assumed the following generators to be out of service:

Plant Name	*Zone*	*Installed capacity*	*Assumed out of service*
Presque Isle 3	2	58 MW	Jan 2010
Presque Isle 4	2	58 MW	Jan 2010
Point Beach 1	4	103 MW	Jan 2011
Point Beach 2	4	105 MW	Jan 2011
Blount 3	3	39 MW	Jan 2013
Blount 4	3	22 MW	Jan 2013
Blount 5	3	28 MW	Jan 2013
Net decrease in 2010		116 MW	
Net decrease after 2010		297 MW	

Please note that recently some of our customer generators reduced their P_{max} outputs, but those reductions occurred after the cutoff points defined below.

1.2.2.a.3 Cutoff dates

For model building purposes, we assumed cutoff dates for generation changes to be included in models. In order to include the latest data in the models, cutoff dates correspond to the dates the models were built as follows:

- 2011 models - October 29, 2009
- 2015 models - October 29, 2009
- 2020 models -October 29, 2009, and
- 2025 models - October, 2009.

It was assumed that if the generator was available as of the cutoff date, it was available for dispatch in that grouping of models.

1.2.2.a.4 Generation projects schedule

To maintain the schedule needed to complete this Assessment, the models were developed during late 2009 and early 2010. Only those generation projects that qualified to be included in our planning models as of the various cutoff dates, were included in the Assessment models.

For generation projects not in service by June 2010, the criterion above resulted in the following proposed generation projects being included in the applicable power flow models:

Plant Name	*Zone*	*Installed capacity increase*	*Dispatched increase*	*Assumed in-service*
Marshfield CT	1	55.2 MW	55.2 MW	May 2010
Oak Creek #2	5	615 MW	615 MW	Aug 2010
Green Lake wind farm	1	32 MW	32 MW	Sep 2010
Quilt Block wind farm	3	19.6 MW	19.6 MW	Dec 2010
Glacier Hills wind farm	3	19.8 MW	19.8 MW	Dec 2010
Stoney Brook wind farm	4	19.7 MW	19.7 MW	Dec 2011
Bowers Road wind farm	3	21 MW	21 MW	Dec 2011
EcoMet wind farm	4	20.1 MW	20.1 MW	Dec 2011
Ledge wind farm	4	30.0 MW	30.0 MW	Dec 2012
Lake Breeze wind farm	4	19.6 MW	19.6 MW	Oct 2013
Net increase by Dec 2011:		802.4 MW		
Net increase 2011-2020:		49.6 MW		

**wind farm Installed capacity lists is 20% of total installed capacity*

A more comprehensive discussion of proposed generation is provided in Generation Interconnections, including a map showing all of the currently active generation interconnection requests that ATC has received (See Figure PR-9.)

1.2.2.a.5 Generation outside system

The model for the system external to ATC was taken from the most appropriate model included in the MMWG 2009 Series models. The external system interchange was adjusted from the 2009 MMWG Series models to match the latest ATC members' firm interchange with the exception of the Shoulder 70% model which was built to represent a 3000 MW import into ATC.

1.2.2.a.6 Generation dispatch

Balancing Authority (Control) area generation was dispatched based on economic dispatch for that Balancing Authority with the exception of the Shoulder 70% model.

1.2.2.a.7 Line and equipment ratings

We revised line and equipment ratings based on updates to our Substation Equipment and Line Database (SELD). As of June 2010, nearly 81 percent of all ATC lines and 89 percent of ATC transformers have SELD ratings that have been validated. Additionally, nearly 96 percent of ATC lines 100 kV or higher have ratings in SELD that have been validated.

Ratings not yet validated in SELD generally are based on the ratings received from the utilities that contributed the facilities to ATC.

1.2.2.a.8 Project criteria included in all assessment models
All of the models built for the Assessment include revised system topology based on projects that were placed in service in the model year, or were anticipated to be placed in service by June 15 of that year. Refer to Tables PF-1 through PF-4 for projects that were included in the analyses. Please also refer to the Project deficient seasonal models, Section *1.2.2.b.1*, for more discussion about how projects are chosen for inclusion our models.

1.2.2.b Steady state power flow models

1.2.2.b.1 Project deficient seasonal models
The load flow models built for the 10-Year Assessment are special models built exclusively for system analyses in the Assessment. Some projects were purposely left out of these models in order to verify system problems and determine which problems worsen over time. We have taken the approach of evaluating subsequent summer peak seasons in each of our annual Assessments to determine the immediacy of needs identified, hence providing a means of prioritization.

The 2011, 2015, 2020 and 2025 steady state project deficient summer peak models were developed to evaluate needs, verify findings of the 2009 Assessment, and confirm that previously identified needs will increase over time. The 2020 and 2025 project deficient models reflect years sufficiently forward in time to determine the need for and assess the performance of larger-scale projects (345-kV lines, for example) that could be expected to be in service in that timeframe.

1.2.2.b.2 All project seasonal models
After the initial analyses portion of the 10-Year Assessment was completed, “All Project” models were built. The “All Project” models were built with all planned and proposed projects in the 2011, 2015 and 2020 models. The later models also include the majority of the provisional projects. These models are more indicative of the expected system configurations for the three study years. The “All Project” models are more appropriate for internal studies performed by ATC planners throughout the year and for regional models. As part of the 10-Year Assessment, the zone planners perform contingency analyses on each of the “All Project” models. These analyses will verify whether all of the planned, proposed, and provisional projects will resolve issues revealed in the 10-Year Assessment process.

1.2.2.b.3 Load, dispatch and interchange profiles

1.2.2.b.3.a Load Sensitivities (2015)

ATC planning explored two sensitivity analyses in our 2010 10-Year Assessment analyses, the minimum (light load) scenario and the high wind generation scenario. The modeling details of these sensitivities are outlined below.

Minimum load scenario (2011)

- ATC Peak Load: 5,515 MW
  - 2009 forecast collection, scalable loads reduced to 32% of peak + non-scalable loads = 40% of Peak load
- Total ATC Generation: 5,297 MW
- Includes all planned and proposed projects to be in-service by 6/15/2011
- *Interchange:* Firm interchange only as of 10/29/2009
- *Dispatch:* ATC-wide Merit order as of 10/29/2009

High wind generation scenario (2015)

- ATC Peak Load: 9,678 MW
  - 2009 forecast collection, scalable loads reduced to 62.5% + non-scalable loads = 67% of Peak load as provided in Operations data
- Total ATC Generation: 8,725 MW
- Includes all planned and proposed projects to be in-service by 6/15/2011
- *Interchange:* ATC net as provided in Operations data -1218
- *Dispatch:* ATC-wide Merit order as of 10/29/2009
- *Special additions:*
  - Wind generation in the ATC footprint dispatched to 61% of P_{max} as provided in Operations data,
  - Wind generation west of ATC dispatched to 50% as provided in Operations data,
  - Wind Generation south of ATC dispatched to 95% as provided in Operations data,
  - Reduce surrounding control area load and dispatch to 80% load level

1.2.2.b.3.b Summer peak (2011, 2015, 2020, 2025)

- ❑ We utilized interconnection point load forecasts provided by various distribution companies in 2009 for both real and reactive power components of load. Please refer to the Load Forecast section for further details.
- ❑ Only firm interchange was included in our analyses.
- ❑ Special additions: none

1.2.2.b.3.b.1 Summer peak 95% Q_{Max} (2011, 2015, 2020, 2025)

- We utilized interconnection point load forecasts provided by various distribution companies in 2009 for both real and reactive power components of load. Please refer to the Load Forecast section for further details.
- Only firm interchange was included in our analyses.
- Special additions: Generator Q_{Max} reduced to 95%.

1.2.2.b.3.b.2 Summer peak 90% Q_{Max} (2011, 2015, 2020, 2025)

- We utilized interconnection point load forecasts provided by various distribution companies in 2009 for both real and reactive power components of load. Please refer to the Load Forecast section for further details.
- Only firm interchange was included in our analyses.
- Special additions: Generator Q_{Max} reduced to 90%.

1.2.2.b.3.c High load model (2015)

- We utilized interconnection point load forecasts provided by various distribution companies in 2009. The 2015 high load (or "hot summer") model was created by increasing load 5 percent above expected summer peak conditions as a proxy for a 90/10 model in order to determine in-service date sensitivity to load growth that is higher or weather that is warmer than forecasted. Please refer to the Load Forecast section for further details.
- The system external to ATC was taken from the MMWG 2009 Series, 2015 summer model.
- The external system interchange was adjusted from the 2009 MMWG Series 2015 summer interchange to match latest ATC members' firm interchange.
- ATC load forecast increased by 5% above the summer peak load forecast using a constant power factor, Planning/Operations coordinated 69-kV ratings included.

1.2.2.b.3.d Shoulder 70% models (2011, 2015)

- We utilized interconnection point load forecasts provided by various distribution companies in 2009.
- The 2015 shoulder model was created by selectively scaling down loads that generally vary by time-of-day to approximately 70 percent of the summer peak condition. A 70 percent load level was chosen to represent the shoulder model because under this scenario, flows are changing as a result of the Ludington pumping cycle. However, we recognize that loads at individual points will vary under real-time shoulder conditions.
- The shoulder 70% model included a 3000 MW import into ATC. Firm interchange plus economic transactions up to a 3000 MW import were included.
- Planning and operations coordinated 69-kV ratings included.

1.2.2.b.3.e Shoulder 90% models (2011, 2015)

- We utilized interconnection point load forecasts provided by various distribution companies in 2009. The 2015 shoulder 90% model was created by decreasing load 10 percent below expected summer peak conditions. Please refer to the Load Forecast section for further details.
- To simulate a steady state reverse east-west bias power flow, models were developed with 90% load levels, 1700 MW import into ATC, and a 2000 MW transaction from east to west.
- ATC system biased in an East to West direction, Planning/Operations coordinated 69-kV ratings included.

1.2.2.b.3.f Model years

We started model development for this Assessment by building a system model that represented 2010 summer peak conditions. This 2010 model is referred to as an "as-built" model because essentially everything in the model is certain to be in service by 2010 summer. This model then was modified to create each of the subsequent Assessment study models including the changes previously described for each model.

Computer simulation model years for the 2010 network Assessment analyses were selected in order to meet NERC requirements for a 1-5 year horizon and beyond the 5 year horizon. The years 2011 and 2015 were selected to meet the 1-5 year horizon. The years 2020 and 2025 meet the beyond 5 year horizon. The years 2011, 2015 and 2020 were chosen to coordinate with the most recently released MMWG models that were available.

The 2011, 2015, 2020 and 2025 models were developed to evaluate needs, verify findings of the 2009 Assessment, and confirm that previously identified needs will increase over time. The 2020 and 2025 models reflect years sufficiently forward in time to determine the need for and assess the performance of larger-scale projects (345-kV lines, for example) that could be expected to be in service in that timeframe.

1.2.2.c Dynamic stability/short-circuit assessment models

We conduct transient analyses to evaluate dynamic stability of generators as part of our study of new generation interconnections and voltage stability analysis on portions of the system where severe low voltages are identified. In instances where our stability criteria were not met, remedial projects were devised and included in this Assessment (see System stability).

We also conduct short circuit analyses as part of our study of new generation interconnections to evaluate the adequacy of circuit breakers on the transmission system. In instances where short-circuit duties exceeded existing circuit breaker ratings, plans for circuit breaker replacements have been included in this Assessment.

1.2.3 Needs and solution development

1.2.3.a Steady state project-deficient needs assessment

1.2.3.a.1 System intact and single contingency simulations
ATC performed system intact and single contingency simulations on the 2011, 2015, 2020 and 2025 models. Single contingency simulations include the following: single element (line, transformer, generator, bus and switched shunt) and event-based breaker-to-breaker outages. We run these simulations for summer peak and under the sensitivity situations described in Section 1.2.2.b.3.

1.2.3.a.2 Comparison of results vs. Planning criteria
The models described in Section 1.2.3.a.1 are analyzed and compared to our Planning Criteria. Limits that approach or exceed our criteria are then listed in Tables ZS-1 through ZS-4.

1.2.3.a.3 Reconciliation of significant changes to power flow results
To reconcile changes in power flow results between Assessments, zone planners run data comparisons to determine if constraints identified in prior Assessments have become more severe, less severe, or have been mitigated. Steps are taken to verify topology and other model changes to ensure that the results are consistent with all of the available information.

1.2.3.a.4 Future considerations
In future Assessments, we will continue to communicate needs and solicit solution development options from our stakeholders early in the process.

1.2.3.b Solution development

1.2.3.b.1 New constraint
If a new constraint is found in the initial screening, the zone planner will take steps to ensure that the constraint is valid, including verification of the power flow model. If the new constraint is within the current five-year timeframe, the zone planner will then check for potential delayability, including investigation of operating guides or other mitigation measures.

After all potential mitigation measures for a given constraint or need have been evaluated, system solution options are developed. Potential projects that may resolve identified needs are vetted internally and with our external customers. Each solution option is subject to sufficient evaluation to determine its effect upon the identified constraint. After all discussion and collaboration has concluded, the results of the solution option evaluation are recorded in a project development document.

Cost estimates are requested from the Project Control Office for solution options that effectively address the identified constraint. After cost information has been obtained, the zone planner selects the most efficient solution option from a cost-benefit standpoint and develops a provisional project request form. Finally, the provisional project request form is processed through ATC's Project Approval Process.

1.2.3.b.2 Repeat constraint

If a previously identified constraint is found in our initial screening, the zone planner will re-verify that existing solution options address that constraint. If an in-service date or scope change is warranted, updated cost estimates are requested from the Project Control Office. The project request form is then updated with the revised in-service date, cost, scope, and/or justification. The updated project request form is then resubmitted through ATC's Project Approval Process.

1.2.3.b.3 Unspecified Network Project (Placeholder) Process

Unspecified Network Projects are defined as those projects which may shift into the 10-year timeframe as a result of:

- Changing load forecast,
- Changes in generation and distribution interconnection projects,
- Changes in mandatory reliability or renewable portfolio standards, and/or
- Additional projects that are driven by economic benefits or multiple outage impacts.

Several million dollars were set aside in ATC's budget in order to address Unspecified Network Projects. ATC's placeholder process begins with internal discussions to determine how to best serve our customers' local and regional needs. In these discussions, we collaboratively determine which projects are likely to be built or incur costs within the 10-year Assessment period. Projects with a 50 percent probability of occurrence or greater are estimated by the Project Control Office. The cost/benefit results are discussed, vetted and approved by our AIM Executive committee. Finally, after consensus is reached, our budget is updated with to include these placeholder dollars.

1.2.3.c All Projects assessment

After the 10-Year Assessment analysis is completed, models are built that include all planned, proposed, and some provisional projects. These models are called "All Projects" models and are more indicative of the expected system configurations for 2011, 2015 and 2020 study years. These models are more appropriate for internal planning studies performed throughout the year.

As part of the 10-Year Assessment, zone planners perform a contingency analysis on each of the "All Projects" models. The contingency analysis includes systematically removing each line, generator, transformer, switched shunt and modeled bus ties individually to determine the affect on the transmission system. The analysis will verify whether all of the planned, proposed, and provisional projects will resolve issues revealed in the Assessment process.

The zone analysis discussions presented in this Assessment provides a list of reinforcements that are beginning to optimize our reinforcement plans, at least at the one- or maybe two-zone level. Three important questions regarding this plan include the following:

- How do the reinforcements for all the zones perform together?
- Does applying a solution in one zone create a problem that was not seen before in another zone?
- Are some zone solutions redundant when all the solutions are applied to the system?

As we did in the 2009 Assessment, this year we attempted to address the first two questions. We built year 2011, 2015 and year 2020 models that included reinforcements reflecting our best thoughts on all of the most likely planned, proposed, and provisional projects to address the identified issues. These projects are those identified in the project tables for this Assessment with specific in-service dates. First contingency analysis was performed on these new models, including selected outages on neighboring systems. This analysis showed that the reinforcements in total did indeed deal with the issues identified and did not create any new issues to be resolved. Please refer to the All Projects section for details of our analyses.

1.2.3.d Stability review & analysis

1.2.3.d.1 System angular stability assessment

For each 10-Year Assessment, generator stability is screened or assessed at all major generating stations connected to the ATC system. Numerous generator interconnection studies add to our knowledge of the ATC system stability response to selected Category B2, C3 and D2 outages that constitute the worst case scenarios for stability perspective. A MRO/RFC joint on-site review completed in December 2008 determined that ATC was fully complaint with NERC Standards that cover multiple outages (Category C), including the system’s stability response to multiple outages.

In the 2010 10-Year Assessment, we revisited a select list of generator stations as described below, conducting simulations by applying NERC Standards for categories B2, C3 and D2 using the 2015 Light Load All Project model. As generator stability concerns arise they are evaluated and appropriate corrective actions are developed and implemented. Generator stations with total net output above 100 MW and associated transmission lines operating above 100 kV are generally selected to assess system angular stabilities.

The methodology used in screening or assessing the major generator stations includes a review to determine that no significant system topological changes have occurred near the generator stations other than local load growth. In addition, the methodology includes a review of the parameter values and the model types used to represent the dynamic response of the units at the generator stations in system angular stability simulations to determine that no significant changes have occurred. This methodology also includes a review of the date the last time a stability study was conducted for a major generator station to determine that the elapsed time does not exceed five years. Considering the number of existing major generator stations shown in Table ZS-7 - ATC System Angular Stability Assessment this requires that at least six major generator stations be included in the system angular stability analysis for each 10-Year Assessment in order to complete a study of all major generator stations in a 5-year sequence.

If these criteria are confirmed, the generator stability results of the previous existing studies remain applicable and are acceptable for the following years with proposed system upgrades. If any of these criteria are not met then the generator stability is screened or restudied, and the preliminary needs and results of the analyses are communicated to our stakeholders. Please refer to System stability analysis for more details.

1.2.3.d.2 System voltage stability assessment

ATC is still developing a rigorous process for assessing voltage stability across the system. Currently we monitored single and multiple contingency voltages for the Rhinelander area which was started in the 2009 10-Year Assessment using the 2008, 2009, and 2013 summer peak all project system models to screen for indications of where voltage stability may be an issue. Additional studies will need to be conducted since the load breakdown data by customer class supplied changed significantly from what had historically been provided and because of the results obtained for some of the NERC C3 contingencies will require additional analysis. We then compare the stability performance against our Planning criteria, document the preliminary needs and results, and communicate those results to our stakeholders.

The MRO/RFC joint on-site review completed in December 2008 determined that ATC was fully compliant with the voltage stability assessment requirements in the applicable NERC standards. Please refer to System stability analysis for more details.

1.2.3.e Multiple outage review & analysis

1.2.3.e.1 Overview

ATC's steady-state multiple outage assessment started with Commonwealth Associates (CAI) performing more extensive analysis of our transmission system in 2004 to identify NERC Category C type contingencies that potentially could lead to cascading. Since then, we have taken this initial screening and enhanced our review in succeeding years.

1.2.3 e.2 Model development

For the 2010 work, ATC used the 2015 and 2020 summer peak models with 95% Q_{max} including all projects identified in the 10-Year Assessment for additional steady state multiple outage analysis. Physical Operational Margin (POM)-Optimal Mitigation Measure (OPM) software was used to determine available mitigation measures that could be used to alleviate identified system constraints that could potentially cause problems. The mitigation measures used were generation re-dispatch, generator reactive power re-dispatch, transformer under load tap changing, capacitor bank adjustment, phase shifter angle adjustment and load-shedding.

1.2.3.e.3 Contingencies studied

NERC Category C contingencies are specific sets of multiple outages including lines, transformers and generators. For this Assessment, we revisited Category C event analysis by evaluating the existing severe multiple outages list, which included:

- 43 multiple outages selected and tested in 2005 studies,
- 16 breaker failure (NERC Category C2) multiple outages selected from 2009 studies,
- 4 bus section (NERC Category C1) multiple outages selected from 2009 studies,
- 30 selected contingencies from Zone 3,
- 5 selected contingencies from Zone 5, and
- 30 selected contingencies from Zone 1 identified in the 2009 studies.

In addition to the above selected multiple outages, 15 selected outages that resulted from new projects in the 2020 model were tested.

In addition to the re-evaluation of previously defined multiple outages, in 2010 we performed additional Category C analyses by screening all 345-kV branches and generators connected to the bulk electric system and all ties into our service territory (100 kV and above). Furthermore, we performed detailed Category C analyses for ATC planning Zones 2 and 4 for 100 kV and above and generators connected to the bulk electric system.

1.2.3.e.4 Contingency types
As part of these analyses, several contingency types are identified. They are as follows:

- C3: N-1-1, combination of transmission lines, transformers and/or generators,
- C5: N-2, two circuits on a common tower,
- C2: Breaker (failure or internal fault), and
- C1: Bus section.

1.2.3.e.5 Contingency thresholds
The screening thresholds are identified as follows:

- Generators connected to Bulk Electric System,
- Voltage level of 100 kV and above for transmission lines,
- Transformer size ≥100 kV, both high and low voltage sides,
- Monitored buses: 69 kV and above, and
- Severe outages: outages that cause system constraints that require loss of load to mitigate in addition to other non load shed remedial actions.

1.2.3.e.6 Contingency analysis
Our contingency analysis was performed by carrying out a full analysis for both the 2015 and the 2020 summer peak models. In addition to the selected multiple outages applied to the 2015 model, multiple outages resulting from new projects were tested using the 2020 model. For both 2015 and 2020 models, a full analysis of ATC Zone 2 and Zone 4 was performed.

1.2.3 e.7 Contingency results
Our results consist of lists of contingencies resulting in thermal constraints, voltage constraints, and voltage stability constraints. Also available are simulation results of available mitigation measures, as estimated by POM-OPM software that can be employed to alleviate identified system constraints. Please refer to Multiple Outages for the results of our analyses.

1.2.4 Documentation

1.2.4.a Writing/approval processes
The 10-Year Assessment is written and developed by several contributors. The following steps are performed in order to ensure cohesive, consistent information:

- ❑ Requests are made for the latest financial, environmental, demographics, asset renewal and economics information from other ATC departments.
- ❑ Drafts of each section’s text, figures and tables are compiled for peer review.

- ❑ A comprehensive meeting is held with all Planning and Asset Renewal managers and team leaders in order to review and approve the information.
- ❑ A summary presentation of all Assessment information is reviewed and approved by ATC management.

Once the information has been approved by all parties, the hard copy Summary Report and Zone Summaries are printed and distributed, and the Full Report text is posted at www.atc10yearplan.com.

1.2.4.b NERC Compliance

ATC was fully compliant with the North American Electric Reliability Council (NERC) Reliability Standards in 2009. In 2010 we continue to be committed to maintaining fully compliant status with all of the existing and newly approved NERC standard requirements.

As noted in previous Assessments, ATC is registered with two of the regional reliability compliance entities, the Midwest Reliability Organization (MRO) and the Reliability*First* Corporation (RFC). This dual reporting arrangement was established because ATC serves customers that are members in each of these Regional Reliability Organizations.

The mandatory NERC Reliability Standards assign accountability for specific requirements based on defined entity functions. ATC registered as the following entities - Transmission Owner, Transmission Operator, Transmission Planner and Planning Authority[1]. The following discussion of NERC compliance in this document will focus on ATC's Transmission Planner accountabilities. One purpose of this section is to enhance our ability to provide documentation of ATC compliance with the Transmission Planner accountabilities.

The primary Transmission Planner compliance responsibilities are system performance assessments and system modeling. The system performance assessment standards include checking for exceeded voltage criteria limits, system equipment overloads, adequate stability, cascading outages, loss of load, and firm transfer curtailments under a wide range of system operating conditions.

The Transmission Planning reliability standards call for the consideration of thirty (30) operating conditions. These conditions are grouped into four (4) categories. The requirements associated with each of the applicable categories are contained in four separate NERC Transmission Planning standards:

A. Normal conditions (Standard TPL-001-0)

[1] NERC has since replaced the Planning Authority function with Planning Coordinator.

B. Single element contingencies (Standard TPL-002-0)
C. Multiple element contingencies (Standard TPL-003-0)
D. Extreme events (Standard TPL-004-0)

ATC has performed assessments annually (from 2001 to 2010), which demonstrated that its portion of the bulk electric system is planned to supply the projected LDC load and firm transmission service for the contingency conditions given in the four applicable NERC Transmission Planning standards. In addition, ATC has performed studies and simulations annually (from 2001 to 2010) that support the 2010 Assessment using the projected LDC load and firm transmission service for the contingency conditions given in the four applicable NERC Transmission Planning standards.

Studies and analyses were performed for the appropriate Category A conditions, as well as Category B, Category C, and Category D contingencies. The Category B contingencies that would produce the more severe system results or impacts are described in the TPL-002 Rationale. The Category C contingencies that would produce the more severe system results or impacts are described in the TPL-003 Rationale. The Category D contingencies that would produce the more severe system results or impacts are described in the TPL-004 Rationale.

All of the identified compliance requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 of the near term (2011 to 2015) Assessment were addressed by the new five-year projects and/or operating procedures that could support our plans to comply with these standards. All of the identified compliance requirements of TPL-001-0, TPL-002-0, and TPL-003-0 of the long term (2016 to 2020) Assessment were addressed by the new 10-year projects and/or operating procedures that could support our plans to comply with these standards.

All existing and planned protection systems, including any backup or redundant systems that would be applicable to a given contingency were simulated in studies and analyses. All existing and planned control devices that would be applicable to a given contingency were simulated in studies and analyses. These control devices include transformer automatic tap changers, capacitor bank automatic controls, and six DSMES units. No specific facility outages are scheduled for the planning horizon at the demand levels that were studied. As the future unfolds and facility outages are scheduled, they will be scheduled for conditions that provide acceptable reliability.

The first set of requirements (R1) in each of these standards deals with the frequency, timeframes, simulations, and conditions of the transmission system assessments. Most of the R1 requirements are met by documentation in this 10-Year Assessment (see references below).

Some R1 requirements are met by a combination of this 10-Year Assessment and the documentation in earlier Assessments. For example, the assessments in the 2009 10-Year Assessment are supported by both the system-wide simulations that were used in this Assessment and project-specific simulations that were performed for earlier assessments. Together these supporting simulations were used to revise the assessment of expected system performance in the near-term (1- to 5-year) planning horizon and other system performance in the long-term (6- to 10-year) planning horizon.

The second set of requirements (R2) in each of the four standards deals with the plans that are proposed to achieve the required system performance. Many of the project plans that were noted in last year's 10-Year Assessment remain unchanged based on subsequent analysis and assessment. However, the 2010 10-Year Assessment describes project scope and need date changes that are required to achieve compliance based on later forecasts, analysis, and studies.

The third set of requirements (R3) in each of the four standards covers documenting and communicating the Assessment and project plans to the MRO and RFC. Taken together, this 2010 10-Year Assessment and earlier Assessments fulfill this requirement.

The listing of potential bulk power system reinforcements to address identified near-term and long-term planning horizon needs are provided in Tables PR-2 through PR-23.

Information regarding studies that are specific to generation interconnection requests is described in the Generation interconnections section. Any publicly available generation interconnection request details and completed study reports can be accessed through the MISO Web site at **http://oasis.midwestiso.org/documents/ATC/Cluster_8_Queue.html**

Compliance Documentation in the 2010 10-Year Assessment

The power system models are derived from cases that were provided by the Multi-Modeling Working Group (MMWG), which prepares cases for industry-wide use. Details regarding the specific system conditions and models that were used in the assessment are given in the Methodology & assumptions section. Additional explanations of the modeling methods and the frequency of system model updating are given in the Model building criteria section of the Planning criteria section.

A complete listing of the planning criteria that we apply, including those which are beyond the NERC, MRO, and RFC planning criteria, can be found in the Planning criteria section.

The system performance assessments for Category A (normal) and Category B (single element contingencies) conditions are given in the Introduction and Reactive power analysis section.

The system performance assessments for Category C (multiple element contingencies) and Category D (extreme event) conditions are contained in the Multiple outage analysis and Reactive power analysis sections.

The compliance requirements dealing with system stability, generator stability, and voltage stability for all four Category (A, B, C, and D) conditions are dealt with in the System stability, Generator stability, and Voltage stability sections.

Descriptions of the system performance studies that are prepared jointly with other interconnection companies, regional groups, or government bodies are given in the Regional analysis section.

ATC's 2010 Assessment of Transmission System Performance
Given the full set of simulations ATC completed for the 2010 Assessment and earlier assessments, ATC assesses its system as being compliant with NERC Standards TPL-001, 2, 3, and 4 for each year of 2011 through 2015 and for the rest of the 10-year planning horizon.

Project justification, development, and prioritization
ATC has and is continuing to develop processes that allow us to identify system needs and opportunities, to develop proper project scope and schedule and to assess project value and priority. These processes include the following.

- Project justification (system needs and opportunities assessments)
- Project development
- Project benefit identification and prioritization

All of these processes are being enhanced to include appropriate stakeholder input.

Project justification

The system needs and opportunities assessments are the key drivers for the project creation and justification process. They are also one of the major subjects of the 10-Year Assessment. ATC has planning criteria and is continuing to develop stakeholder input processes to help determine which projects bring value and have appropriate justification.

Project development

There are four possible stages in the Planning portion of a project's development:

- ❑ System Needs and Opportunities Identification
- ❑ Project or Program Development and Continued Need Investigation
- ❑ Project Alternatives or Program Solutions Development and Preferred Alternative Identification

- ❑ Project/Program Scope and Proposed Project Request Development

System Needs and Opportunities Identification

ATC system needs and opportunities are investigated and identified on an ongoing basis. However, particular attention is given to the system reliability needs assessment on an annual basis as required for compliance with the NERC Reliability Standards on transmission system performance. All identified system needs or opportunities are evaluated and compared to each other for possible interrelationships and coordination. In addition, comments on identified needs and opportunities are solicited within ATC and from external customers when it is practical.

Project or Program Development and Continued Need Investigation

After one or more future transmission system needs or opportunities are identified, Solution Options that may address the identified needs are solicited within ATC and from external Customers. Each Solution Option is subject to sufficient evaluation to determine whether it would work to mitigate the identified needs. The results of the Solution Option evaluation are recorded in a project development document. The continuity of identified needs is investigated on at least an annual basis when the system reliability needs assessment is updated.

If a Proposed Project Request is not needed until a future date, a Provisional Project Request is prepared for one of the Solution Options that works. Preliminary project scope and cost estimates are developed for the selected Solution Option. The Provisional Project description is recorded in a project request document and is submitted to add the project to the ATC capital budget.

Project Alternatives or Program Solutions Development and Preferred Alternative Identification

All of the Solution Options that work are classified as project Alternatives. Preliminary project scope and cost estimates are prepared and documented for each Alternative. Any other relevant Alternative considerations are also identified and documented. The Alternatives are compared to each other to determine which one is the Preferred Alternative. The Preferred Alternative selection is reviewed and approved within ATC and by any pertinent Customers. The comparisons and conclusion are recorded in a Project Scoping Document.

Project/Program Scope and Proposed Project Request Development

Detailed project/program scope and cost estimates are developed for the Preferred Alternative. The Proposed Project/Program is reviewed and approved within ATC and by any pertinent customers. For projects, the description is recorded in the Project Scoping document and a Proposed Project Request is submitted to add the project to the ATC capital budget.

Project benefit identification and prioritization

In 2010~~,~~ ATC continued to adapt its project prioritization methodology to be more focused on the consideration of: (1) project/program cost metrics, (2) project/program benefit metrics, and (3) project/program advancement and deferral flexibility.

The following discussion presents a description of the project benefit and prioritization method that ATC continues to develop to appropriately value and prioritize projects. Project benefit identification helps to understand the value of different projects compared to their cost. Project prioritization is a consideration to help resolve capital budget and human resource constraint issues. It may also assist company employees in the prioritization of their work and provide guidance for scheduling pre-certification activities.

The project benefit and prioritization method is being used as a screening tool to identify projects that are candidates for capital budget advancement or deferral. It should be noted that project benefit identification and prioritization by itself does not cause a project to be advanced or delayed. It is only a tool for screening projects that may have reason to be advanced or delayed compared to others. If there are compelling reasons to modify the capital budget, then we will consider this tool, as well as risk and with appropriate input from stakeholders to evaluate the possible effects of advancing or delaying selected projects. However, the final decision of whether a candidate project will be advanced or deferred is still reached by considering the specific details of each project, including appropriate stakeholder input.

The project benefit metrics have also been helpful in the comparison of multiple alternatives to address the same system needs and identifying the preferred alternative.

Project/Program Cost Metrics

The preliminary project/program costs that are used in the project benefit and prioritization methodology are the costs from the customer perspective. These costs are usually the capital project draft budget dollars (project request cost estimate) or capital project construction cash flow dollars (actual and remaining cash flow costs). These cost metric values are developed by the Business Administration Service department using their established cost estimate methods and assumptions.

- ❑ *Total Capital Costs* – the total capital cost associated with the project/program referred to an appropriate budget year. Once the project/program is in the capital budget, then the cost is the NPV of the revenue requirement being driven by the project based on the actual and projected capital costs to-date in our 10-year capital forecast.

- *Capital Costs Remaining* – once the project/program is in the capital budget, then the cost is the NPV of the associated revenue requirement being driven by the project based on the actual capital costs to-date in our 10-year capital forecast.
- *Total Operation and Maintenance (O&M) Costs* – total O&M cost associated with the project/program referred to an appropriate budget year. Once the project/program is in the capital budget, then the cost is the NPV of the revenue requirement being driven by the project based on the actual and projected O&M costs to-date in our 10-year capital forecast.
- *O&M Costs Remaining* – once the project/program is in the capital budget, then the cost is the NPV of the associated revenue requirement being driven by the project based on the actual O&M costs to-date in our 10-year capital forecast.

Project/Program Benefit Metrics

Project/program benefits are captured and used for prioritization purposes through a number of benefit metrics.

The preliminary benefit metrics that are being used in the project benefit and prioritization methodology are given below.

Cost Savings

- *Capital cost savings* – The net present value (NPV) dollars of the revenue requirement (RR) for 40 years of associated capital cost savings).
- *Operating and maintenance (O&M) cost savings* – The NPV dollars of the RR for 40 years associated O&M savings).
- *Direct customer cost savings* – The NPV of the revenue requirement for 40 years of associated direct customer savings. Basically the different between a Distribution Only solution and the chosen solution.
- *Losses reduction savings* – The net present value of the expected savings associated with the reduction in system losses by the implementation of the project over 20 years.

Access/Capacity Improvements

- *Congestion reduction savings* – The net present value of the expected 70/30 savings metric from PROMOD economic analysis program for 40 years.
- *Potential import/export transfer capability increase* – The amount of potential incremental import/export transfer capability that is added by the implementation of the project. The basis for the capability value is the summer normal rating or the manufacturer’s nameplate rating of the associated facilities.

- *Potential internal transmittal capability increase* – The amount of potential incremental generation capability, load-serving capability, or transmission circuit capability that is added by the implementation of the project. The basis for the capability value is the summer normal rating or the manufacturer's nameplate rating of the associated facilities.

Compliance/Performance Criteria Fulfillment

- *Number of forecasted compliance needs addressed* – The number of NERC single contingencies, which produce system performance needs according to the 10-years-in-the-future system assessment that would be addressed by the implementation of the project.
- *Reduction in the amount of load at risk for the most significant forecasted compliance need* – The reduction in the amount of load and/or generation, which would be at risk for the most significant NERC compliance need in the 10-years-in-the-future system assessment that would be addressed by the implementation of the project.
- *Number of forecasted ATC criteria needs addressed* – The number of ATC (non-NERC) single contingencies, which produce system performance needs according to by the 10-years-in-the-future system assessment that would be addressed by the implementation of the project as indicated.
- *Reduction in the amount of load at risk for the most significant forecasted ATC criteria need* – The reduction in the amount of load and/or generation, which would be at risk for the most significant ATC criteria need in the 10-years-in-the-future system assessment that would be addressed by the implementation of the project.

Asset Renewal/System Performance Improvements

- *Sustained outage count reduction* – The expected sustained outage count reduction per year for the life of the project.
- *Sustained outage energy reduction* – The expected sustained outage energy reduction per year for the life of the project. This calculated from the average amount of load that is expected to be outaged multiplied by the average number of outages per year and the average outage duration.
- *Momentary outage count reduction* – The expected sustained outage count reduction per year for the life of the project.
- *Momentary outage load reduction* – The expected momentary outage load reduction per year for the life of the project. This value is the average amount of load that is expected to be outage by each event multiplied by the average number of events per year.

- *Safety performance* – The increase in the margin of safety or of the performance ratings limits of a piece of equipment (e.g. breaker) or facility (e.g. transmission line).

Environmental Improvements

- *SF_6 gas reduction* – The expected reduction in the release of SF_6 gas due to the repair of leaks or avoidance of breaker failure.
- *PCB fluid reduction* – The expected reduction in the release of PCB fluid due to the removal or replacement of equipment with PCBs.
- *Lead reduction* – The expected reduction in the release of lead due to the removal or replacement of equipment with lead.

The benefit metrics are not “weighted”. Each benefit metric value is independent and not normalized or otherwise correlated with respect to any of the other benefit metrics.

A benefit metric value is only developed if the benefit is expected to be significant and able to be quantified with an appropriate amount of effort. Limited or no benefit metrics are generally developed for Provisional projects. No benefit metrics are generally developed for Conceptual (Placeholder) projects.

We re-emphasize that the project benefit and prioritization method is being used as a screening tool to identify projects that are candidates for capital budget advancement or deferral. Project benefit identification and prioritization by itself does not cause a project to be advanced or delayed. It is only a tool for screening projects that may have reason to be advanced or delayed compared to others. If there are compelling reasons to modify the capital budget, then we will consider this tool, as well as risk and with appropriate input from stakeholders to evaluate the possible effects of advancing or delaying selected projects. However, the final decision of whether a candidate project will be advanced or deferred is still reached by considering the specific details of each project, including appropriate stakeholder input.

Table PF-1
Projects included in the 2011 10-Year Assessment Model

System additions	Planning zone
Construct Crane Creek G551 wind farm	1
Construct Brandon-Fairwater 69-kV line	1
Rebuild Arpin-Rocky Run 345-kV line	1
Construct MEWD CT G588 generator	1
Uprate P-120 Hume-Arpin 115-kV line	1
Construct Green Lake wind farm G376	1
Construct ACEC Badger West T-D 138-kV Substation	1
Construct Warrens T-D 69-kV Substation	1
Uprate Chandler-Delta # 2 69-kV line to 167 degrees	2
Construct ring bus at the Pine River 69-kV Substation and replace 1-5.4 MVAR capacitor bank with 2-4.08 MVAR banks	2
Install one 8.16 MVAR 138-kV capacitor bank at Hiawatha Substation	2
Install one 4.08 MVAR 138-kV capacitor bank at Osceola Substation	2
Uprate Chandler-Delta # 1 69-kV line to 167 degrees	2
Uprate Chandler-Lakehead Tap-Masonville 69 kV line to 167 degrees	2
Uprate Autrain 69-kV line to 293 Amps all season	2
Uprate Winona-M38 138-kV line to 125 degrees	2
Install a 4.08 MVAR 69-kV capacitor bank at the L'Anse Substation	2
Construct Centennial T-D 69-kV Substation	2
Uprate Forsyth-Munising 138 kV line to 200 degrees	2
Install Iron Grove 138/69-13.8 kV transformer	2
Install 2-8.16 MVAR 69-kV capacitor banks at Indian Lake Substation	2
Tap new Sun Valley 69-kV T-D Substation into the Y-119 Verona-Oregon line	3
Rebuild Hillsboro-Dayton 69-kV line	3
Construct 138-kV line from Oak Ridge to Verona with a 138/69 kV transformer at Verona	3
Tap Mazomanie West T-D 69-kV Substation into line Y-62	3
Uprate Walworth-North Lake Geneva 69-kV line	3
Construct Paddock-Rockdale 345-kV line	3
Upgrade existing Sheepskin 10.8 MVAR capacitor bank to 16.2 MVAR	3
Install 2-9.6 MVAR capacitor banks at Dickinson 138-kV Substation	3
Rebuild Verona-Oregon 69 kV line Y-119	3
Uprate Royster-Femrite 69-kV line	3
Install Walnut 69/13.8-kV transformer # 3	3
Uprate Colley Road-Marine 138-kV line	3
Rebuild the Blanchardville-Forward 69-kV line	3
Construct LaMar T-D 69-kV Substation	3
Construct Lafayette wind farm G282	3
Install new Milton DIC T-D 69 kV Substation on the LaMar-Harmony Tap 69 kV line	3
Construct Randolph-EC wind farm G706	3
Construct Bowers Road wind farm G546	3
Install 2-16.33 MVAR 69-kV capacitor bank at Spring Green Substation	3
Construct Beloit Gateway T-D 138-kV Substation	3
Replace Femrite transformer # 4 with a 20 MVA transformer	3

Table PF-1 (continued)
Projects included in the 2011 10-Year Assessment Model

System additions	Planning zone
Construct Schofield T-D 69-kV Substation	3
Tap new Greenleaf T-D Substation into Forest Junction-Rockland 138-kV line	4
Uprate Point Beach-Sheboygan 345-kV line to 167 degrees	4
Tap new SBU Michigan T-D 69 kV Substation into Dunn Road-First Avenue 69-kV line	4
Uprate Cypress-Arcadian 345-kV line to 125 degrees	4
Uprate Point Beach generator #1	4
Construct Stony Brook wind farm G590	4
Install a second 345/138-kV transformer at Kewaunee Substation	4
Uprate Point Beach generator #2	4
Install a second 138/26.2-kV transformer at Maple Substation	5
Rebuild Oak Creek-Root River 138-kV line	5
Install third 345/138-kV transformer at Granville Substation	5
Construct Oak Creek generation (Phase I)	5
Install 2x32.4 MVAR capacitor banks at Summit 138-kV Substation	5
Uprate Bain-Albers 138-kV line	5
Uprate Oak Creek-Nicholson 138-kV line	5
Construct Oak Creek generation (Phase II)	5
Install a second 138-kV parallel underground line from Humboldt terminal to Shorewood Substation	5
Install three new Harbor T-D transformers	5
Install second Pleasant Valley 138/24.9-kV transformer	5
Construct Barland T-D 138-kV Substation on the Ramsey-Norwich 138 kV line	5
Uprate Bain-Kenosha 138-kV line	5
Rebuild/convert Twin Falls-Plains 69-kV double-circuit line to 138/69-kV double-circuit	1 & 2

Table PF-2
*Projects included in the 2015 10-Year Assessment Model**

System additions	Planning zone
Construct Woodmin T-D 115-kV Substation	1
Rebuild Brodhead-South Monroe 69-kV line	3
Construct Southwest Verona T-D 69-kV Substation	3
Construct Hawk T-D 138-kV Substation	3
Construct Rockdale-West Middleton 345-kV line	3
Construct Hanson Road T-D Substation	3
Upgrade West Middleton transformer # 7	3
Construct EcoMet wind farm G611-G927 and related uprates	4
Construct Ledge Wind G773	4
Construct Lake Breeze wind farm G427	4
Install a second T-D transformer at the Tosa 138-kV Substation	5

**Projects included in addition to those listed in Tables PF-1*

Table PF-3
*Projects included in the 2020 10-Year Assessment Model**

System additions	Planning zone
Install second Blackhawk T-D transformer	3

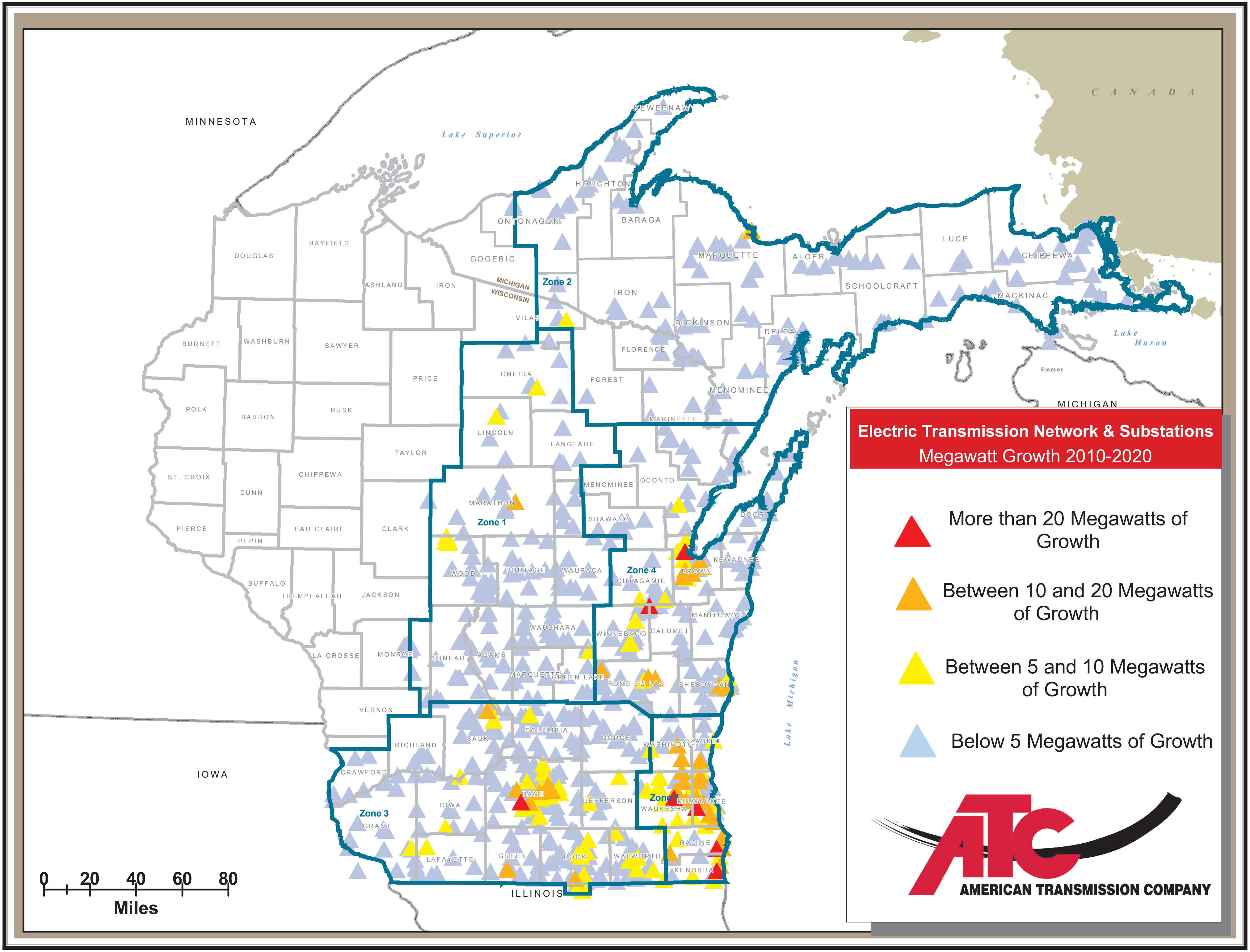
**Projects included in addition to those listed in Tables PF-1 and PF-2*

Table PF-4
*Projects included in the 2025 10-Year Assessment Model**

System additions	Planning zone
None	

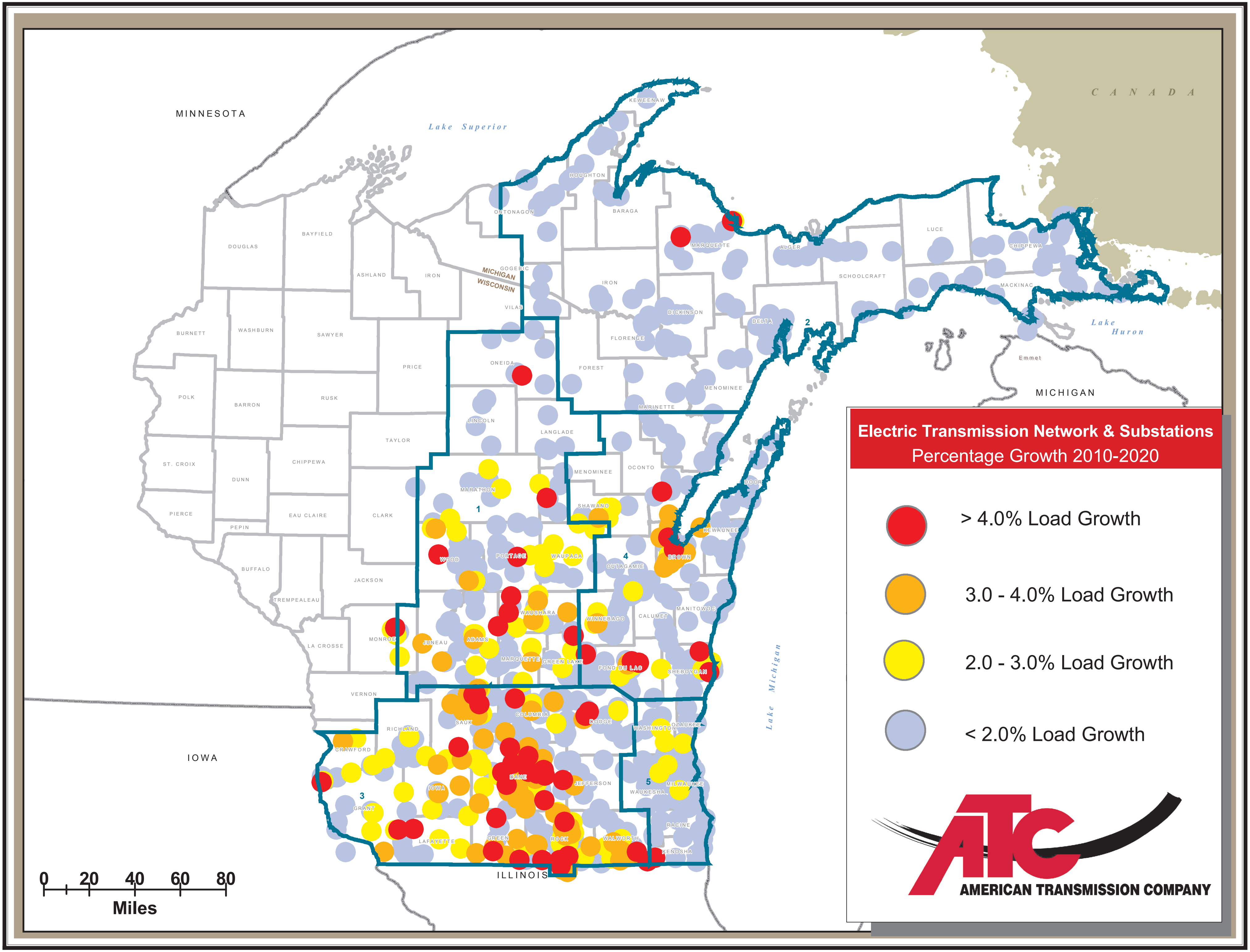
**Projects included in addition to those listed in Tables PF-1, PF-2 and PF-3*

Figure PF-1



Created: March 25, 2010

Figure PF-2



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