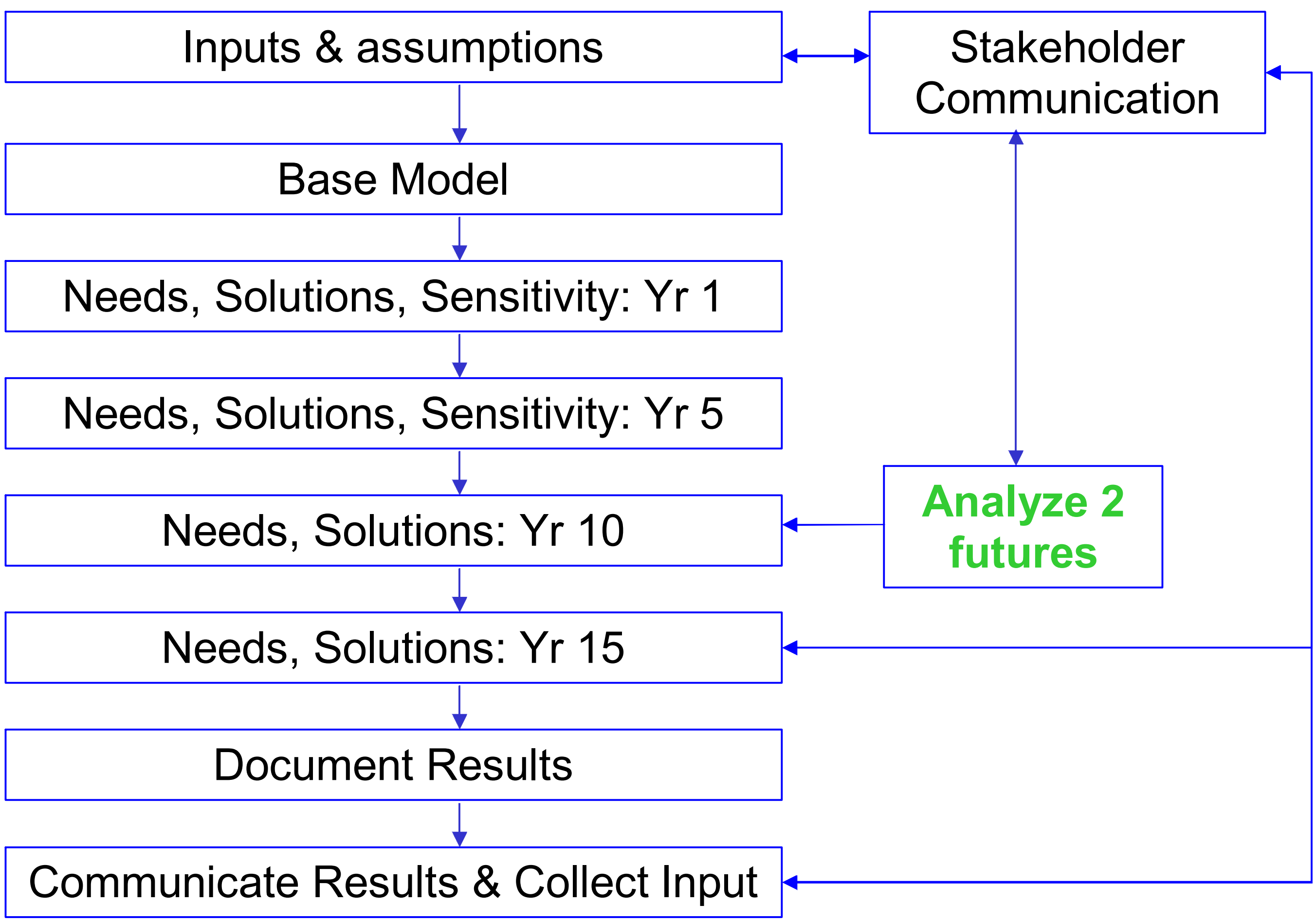
October 2009 10-Year Assessment
www.atc10yearplan.com

Methodology & assumptions
1.1 Overview
ATC conducts annual simulations of its transmission system that review the near-term and longer-term planning horizons as defined in the NERC Standards.

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 assessment process is summarized in the below figure:



As shown in the above figure, stakeholder input was considered earlier in the 2009 Assessment process. As part of this process, certain phases of the sensitivity analyses were replaced with Futures analyses in Year 10.

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 2009 10-Year Transmission System Assessment provides current results of planning activities and analyses of the company's transmission facilities. These activities and analyses identify preliminary 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 2009 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 2010 and 2014 were selected to meet the 1-5 year horizon. The years 2019 and 2024 meet the beyond 5 year horizon. A range of system conditions and study years were developed and analyzed for the 2009 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 2009 network Assessment was developed in a chronological fashion. Planned transmission additions expected to be in service by June 2010 were included in the 2010 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 2014, 2019 and 2024 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 2018 (and in some cases 2019/2024). 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 11^{th}-year load forecast for the year 2019. To obtain a forecast for 2019, certain customer-provided forecasts were extended by growing their load by a fixed growth percentage based upon the previous 3-years' growth (approximately 1.8% compounded annually). Non-scalable loads were held at their 2018 levels using this methodology.

The 2024 summer peak load model was developed utilizing similar methodology. To obtain a projection for 2024, customer-provided forecasts were extended by growing their load by a fixed growth percentage based upon the previous 3-years' growth (approximately 1.6% compounded annually). Non-scalable loads were once again held at their 2018 (or 2019) load levels. It should be noted that the loads utilized in the 2024 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 2024 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	13,911	N/A
2014	14,958	1.8% (2010-2014)
2019	16,322	1.8% (2014-2019)
2024	17,709*	1.6% (2019-2024)
Overall		1.8% (2010-2024)

**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

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 2009 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 2009 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 2009 and 2010 models showed these generators as out of service. The 2014 and 2019 should have had these generators in-service and dispatched.

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 2009 10-Year Assessment models we assumed the following generators were 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
Blount #3	3	39 MW	Jan 2011
Blount #4	3	22 MW	Jan 2011
Blount #5	3	28 MW	Jan 2011
Oak Creek #9	5	18 MW	Oct 2008
Total net decrease		223 MW	

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:

- 2010 models - November 7, 2008
- 2014 models - November 7, 2008
- 2019 models -November 26, 2008, and
- 2023 models - November 26, 2008.

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

Generation projects schedule
To maintain the schedule needed to complete this Assessment, the models were developed during late 2008 and early 2009. 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 2009, 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*
Concord #3	5	6 MW	6 MW	Jun 2009
Concord #4	5	6 MW	6 MW	Jun 2009
Oak Creek #1	5	650 MW	650 MW	Sept 2009
Twin Creeks wind farm	4	19.6 MW	19.6 MW	Oct 2009
Stoney Brook wind farm	4	19.7 MW	19.7 MW	Jan 2010
Bowers Road wind farm	3	21 MW	21 MW	Mar 2010
Green Lake wind farm	1	32 MW	32 MW	Mar 2010
Lafayette wind farm	3	19.6 MW	19.6 MW	Mar 2010
Lake Breeze wind farm	4	19.6 MW	19.6 MW	Mar 2010
Randolph wind farm	3	16 MW	16 MW	Mar 2010
Whistling Wind wind farm	3	10 MW	10 MW	Mar 2010
Marshfield combustion turbine	1	55.2 MW	55.2 MW	May 2010
Oak Creek #2	5	650 MW	650 MW	Sept 2010
EcoMet wind farm	4	20.1 MW	20.1 MW	Jan 2011
Net increase by Dec 2009:		681.6 MW	681.6 MW	
Net increase 2010-2019:		863.2 MW	863.2 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**.**)

Generation outside system
The model for the system external to ATC was taken from the most appropriate model included in the MMWG 2008 Series models. The external system interchange was adjusted from the 2008 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.

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.

Line and equipment ratings
We revised line and equipment ratings based on updates to our Substation Equipment and Line Database (SELD). As of June 2009, nearly 57 percent of ATC lines and 79 percent of ATC transformers 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.

Project criteria included in all assessment models
Refer to Tables PF-1 through PF-4 for projects that were included in the project-deficient analyses. These 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. Please also refer to the Project deficient seasonal models, Section *1.2.2.b*, for more discussion about how projects are chosen for inclusion our models.

1.2.2.b Steady state power flow models

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 2010, 2014, 2019 and 2024 steady state project deficient summer peak models were developed to evaluate needs, verify findings of the 2008 Assessment, and confirm that previously identified needs will increase over time. The 2019 and 2024 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.

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 2010, 2014 and 2019 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.

Load, dispatch and interchange profiles

Summer peak (2010, 2014, 2019, 2024)

- ❑ We utilized interconnection point load forecasts provided by various distribution companies in 2008 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: WPS estimated transformer losses modeled, Nelson Dewey 3 and associated projects not included.

Summer peak 95 percent Q_{max} (2010, 2014, 2019, 2024)

- ❑ We utilized interconnection point load forecasts provided by various distribution companies in 2008 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 percent, WPS estimated transformer losses modeled. Nelson Dewey 3 and associated projects not included.

Summer peak 90 percent Q_{max} (2010, 2014, 2019, 2024)

- ❑ We utilized interconnection point load forecasts provided by various distribution companies in 2008 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 percent, WPS estimated transformer losses modeled. Nelson Dewey 3 and associated projects not included.

High load model (2014)

- ❑ We utilized interconnection point load forecasts provided by various distribution companies in 2008. The 2014 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 2008 Series, 2014 summer model.
- ❑ The external system interchange was adjusted from the 2008 MMWG Series 2014 summer interchange to match latest ATC members' firm interchange.
- ❑ WPS estimated transformer losses modeled, ATC load forecast increased by 5 percent above the summer peak load forecast using a constant power factor, Planning/Operations coordinated 69-kV ratings included, Nelson Dewey 3 and associated projects not included.

Shoulder 70 percent models (2010, 2014)

- ❑ We utilized interconnection point load forecasts provided by various distribution companies in 2008.
- ❑ The 2014 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 percent model included a 3000 MW import into ATC. Firm interchange plus economic transactions up to a 3000 MW import were included.
- ❑ Special additions: WPS estimated transformer losses modeled, ATC load forecast increased by 5 percent above the summer peak load forecast using a constant power factor, Planning and

operations coordinated 69-kV ratings included, Nelson Dewey 3 and associated projects not included.

Shoulder 90 percent models (2010, 2014)

- We utilized interconnection point load forecasts provided by various distribution companies in 2008. The 2014 shoulder 90 percent 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 east-to-west bias power flow, models were developed with 90 percent of peak load levels, 1700 MW import into ATC, and a 2000 MW transaction from parts of RFC to certain areas of MRO.
- Special additions: WPS estimated transformer losses modeled, ATC system biased in an east-to-west direction, Planning/Operations coordinated 69-kV ratings included, Nelson Dewey 3 and associated projects not included.

Light load models (2010, 2014)

- We utilized interconnection point load forecasts provided by various distribution companies in 2008. The 2014 light load 50 percent model was created by decreasing load 60 percent below expected summer peak conditions for those loads expected not to vary by time.
- The model for the system external to ATC was taken from the MMWG 2008 Series light load (2009LL) models.
- Special additions: WPS estimated transformer losses modeled.

Futures (2019)

ATC planning decided to explore the impact of using a security constrained economic dispatch (SCED), in addition to a merit order dispatch, in its reliability analyses. To do this, output from the PROMOD model for the peak load hour from ATC's 2018 Slow Growth and DOE 20% Wind Futures was provided. This output included ATC's total load, flows on all of ATC's tie lines, and dispatch of all of the generators within our footprint for the peak hour in each of the two futures. The PROMOD Analysis Tool (PAT) was used to extract the data. This extracted PROMOD data was then incorporated into 2018 summer peak load flow models for study purposes. A summary of the data provided from PROMOD/PAT is listed below.

PROMOD simulates random forced outages of generators and these are also listed for each future. PROMOD models for ATC's futures are developed from MISO models. MISO added some wind plants within the ATC footprint to its 20% DOE PROMOD model to achieve the mandate. The total amount of wind power added by MISO to its 20% DOE PROMOD model and dispatched on peak within ATC is listed below.

Slow growth future

- ATC Peak Load: 13,593 Megawatts
- Total ATC Generation: 12,879 Megawatts
- Total Tie Line Flows (Imports): 714 Megawatts
- Generators Forced Off in PROMOD: Oak Creek 5, Presque Isle 8, Concord 1, Rock River 1 and Eagle River.

- Wind generation not included in the PROMOD model primarily due to suspended status as of October 2008: Whistling Wind (10 Megawatts), Lake Breeze (19.6 Megawatts), Bowers Road (21 Megawatts), Green Lake (32 Megawatts)

DOE 20% wind future

- ATC Peak Load: 15,999 Megawatts
- Total ATC Generation: 14,602 Megawatts
- Total Tie Line Flows (Imports): 1,397 Megawatts
- Generators Forced Off in PROMOD: Oak Creek 5, Presque Isle 8, Concord 1, Rock River 1 and Eagle River.
- Wind generation not included in the PROMOD model primarily due their suspended status as of October 2008: Whistling Wind (10 Megawatts), Lake Breeze (19.6 Megawatts), Bowers Road (21 Megawatts)
- Total Dispatched Wind Plant Generation Added by MISO: 441 Megawatts
  - MISO added wind plant generation within ATC to meet a 20 percent wind requirement.
  - Substations where wind generation was added by MISO: Plains 345-kV (68 Megawatts), Columbia 345-kV (29 Megawatts), Dead River 345-kV (330 Megawatts), Kewaunee 345-kV (14 Megawatts)
- Total Dispatched Combustion Turbine Generation Added by MISO: 526 Megawatts
  - MISO added combustion turbine (CT) generation within ATC to help meet load growth
  - Substation where CT was added by MISO: Rocky Run 345-kV (526 Megawatts)

Model years

We started model development for this Assessment by building a system model that represented 2009 summer peak conditions. This 2009 model is referred to as an “as-built” model because essentially everything in the model is certain to be in service by 2009 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 2009 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 2010 and 2014 were selected to meet the 1-5 year horizon. The years 2019 and 2024 meet the beyond 5 year horizon. The years 2010, 2014 and 2019 were chosen to coordinate with the most recently released MMWG models that were available.

The 2010, 2014, 2019 and 2024 models were developed to evaluate needs, verify findings of the 2008 Assessment, and confirm that previously identified needs will increase over time. The 2019 and 2024 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 Preliminary needs and solution development

1.2.3.a Steady state project-deficient needs assessment

System intact and single contingency simulations
ATC performed system intact and single contingency simulations on the 2010, 2014, 2019 and 2024 models. We run these simulations for summer peak and under the sensitivity situations described in Section 1.2.2.b. System intact conditions were analyzed at 90% Q_{max}, whereas the single contingency conditions were analyzed at 95% Q_{max}.

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.

Future considerations
In future Assessments, we plan to communicate needs and solicit solution development options to our stakeholders earlier in the process.

1.2.3.b Preliminary solution development

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.

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.

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 2010, 2014 and 2019 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, 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 2008 Assessment, this year we attempted to address the first two questions. We built year 2010, 2014 and year 2019 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

The MRO/RFC joint on-site review completed in December 2007 determined that ATC was fully compliant with the angular and voltage stability assessment requirements in the applicable NERC standards. The following sections describe our review for the 2009 10-Year Assessment.

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.

In the 2009 10-Year Assessment, we revisited a select list of generator stations as described below, conducting simulations by applying NERC Standard TPL-001 for categories B2, C3 and D2 using the 2014 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.

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.

Please refer to System stability analysis for more details.

1.2.3.e Multiple outage review & analysis

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, ATC has taken this initial screening and enhanced our review in succeeding years.

Model development
For the 2009 work, ATC used the 2014 and 2019 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 the amount of load that needed to be shed to avoid cascading.

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:

- 98 multiple outages selected and tested in 2005 studies.
- 23 multiple outages associated with 345-kV facilities
- 28 contingencies from Zone 3, and

In addition to the re-evaluation of previously defined multiple outages, in 2009 we performed additional Category C analyses by screening six contingencies identified in 2008 for Zone 5 (100-kV and above), all 345-kV branches and generators connected to the bulk electric system and all double ties into our service territory (100-kV and above). Furthermore, we performed Category C1 and C2 bus outages for our 100 kV and above system. Finally, we performed detailed multiple contingency analyses for the Zone 1 100 kV and above system branches and generation.

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.

Contingency thresholds
The screening thresholds are identified as follows:

- Generators connected to the Bulk Electric System
- Voltage ≥100 kV,
- Transformer size ≥100 kV, both high and low voltage sides, and
- Severe outages: outages leading to loss of load.

Contingency analysis
Our contingency analysis was performed by looking at all studied contingencies in the 2014 summer peak "All Projects" model with 95% Q_{max}. All severe contingencies identified in the 2014 model were then applied to the 2019 summer peak, 95% Q_{max} model.

Contingency results
Our results consist of lists of contingencies resulting in thermal or voltage violations, lists of unsolved cases, available mitigation measures, and outages with no available mitigation measures. 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.

Table PF-1
Projects included in the 2010 10-Year Assessment Model

System additions	Planning zone
Construct new Hwy 22 345-kV Substation	1
Construct Gardner Park-Hwy 22 345-kV line	1
Rebuild Whitcomb-Caroline 138-kV line J-36	1
Construct Brandon-Fairwater 69-kV line	1
Construct 69-kV line from new Warrens Substation to the Council Creek-Tunnel City 69-kV line	1
Rebuild Arpin-Rocky Run 345-kV line	1
Construct Green Lake wind farm and related projects	1
Relocate Cedar Substation (North Lake)	2
Uprate Cornell-Chandler 69-kV line to 167 degrees	2
Rebuild/convert Conover-Plains 69-kV line to 138 kV	2
Construct 138 kV bus and install a 138/69 kV, 60 MVA transformer at Iron Grove Substation	2
Construct 138 kV bus and install a 138/69 kV, 60 MVA transformer at Aspen Substation	2
Install 2-16.33 MVAR capacitor bank at Perkins 138-kV Substation	2
Relocate Iron River Substation (Iron Grove)	2
Install 1-8.2 MVAR capacitor bank at Hiawatha 138-kV Substation	2
Install 1-4.08 MVAR capacitor bank at L'Anse 69 kV	2
Install 1-4.08 MVAR capacitor banks at Osceola 69 kV	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 1-16.33 MVAR capacitor bank at Indian Lake 138-kV Substation	2
Install 1-8.16 MVAR capacitor banks at the M38 138-kV Substation	2
Construct Butler Ridge 138-kV Substation	3
Upgrade Sheepskin capacitor bank from 10.8 MVAR to 16.2 MVAR	3
Uprate Y-41 Walworth- North Lake Geneva 69-kV to achieve a 69 MVA summer emergency rating	3
Construct new Oak Ridge-Verona 138-kV line and install a 138/69-kV transformer at Verona with a 100 MVA summer normal rating	3
Construct second Paddock-Rockdale 345-kV line and replace 345/138-kV transformer T22 at Rockdale Substation	3
Uprate the Royster Substation terminals	3
Install 2-16.33 MVAR 69-kV capacitor banks at Spring Green Substation	3
Uprate 6632 Rockdale to Jefferson 138-kV line	3
Install 2-24.5 MVAR 138 kV capacitor banks at Artesian Substation	3
Convert Rock River to Bristol to Elkhorn 138-kV operation; rebuild Bristol with a new 138 kV bus	3
Construct a new 138-kV line from North Madison to Huiskamp	3
Construct a new 138/69-kV substation near Huiskamp and install a 138/69-kV transformer with a 187 MVA summer emergency rating	3
Uprate 58751 Boxelder to Stony Brook 138-kV line	3
Uprate Y-152 North Lake Geneva-Lake Geneva 69-kV line to achieve a 115 MVA summer emergency rating	3
Rebuild Stoughton Substation bus	3
Uprate X-8 Rockdale to Boxelder 138-kV line	3
Install one temporary 12.24 MVAR 69-kV mobile capacitor bank at Spring Green Substation	3

Table PF-1 (continued)
Projects included in the 2010 10-Year Assessment Model

System additions	Planning zone
Expand the existing 69-kV capacitor bank from 5.4 to 8.1 MVAR at Richland Center Olson Substation and install 1-7.8 MVAR 12.4-kV capacitor bank at Brewer Substation	3
Install 3-16.33 MVAR 138-kV capacitor banks at North Beaver Dam Substation	3
Rebuild the Y-119 Verona to Oregon 69-kV line	3
Construct Stony Brook wind farm and related projects	3
Install 2-24.5 MVAR Kilbourn capacitor banks	3
Construct Lafayette wind farm and related projects	3
Construct Bowers Road wind farm and related projects	3
Construct Randolph wind farm and related projects	3
Construct Whistling Wind wind farm and related projects	3
Construct Lake Breeze wind farm and related projects	4
Install 2-32 MVAR capacitor banks at Summit 138-kV Substation	5
Install 138/69-kV transformer at the expanded Menominee Substation	4
Expand the Menominee 69-kV Substation and install 138 kV terminals. Loop the West Marinette-Bay De Noc 138-kV line into the Substation	4
Rebuild Crivitz-High Falls 69-kV double circuit line	4
Rebuild Badger-West Shawano 138-kV line	4
Construct Morgan-Werner West 345-kV line	4
String a new 138-kV line from Clintonville-Werner West primarily on Morgan-Werner West 345-kV line structures	4
Rebuild White Clay-East Shawano 138-kV line	4
Construct Twin Creeks wind farm and related projects	4
Rebuild 2.37 miles of 69 kV from Sunset Point to Pearl Ave with 477 ACSR	4
Rebuild Badger-Clintonville 138-kV line	4
Uprate Oak Creek-Nicholson 138-kV line	5
Uprate Oak Creek-Root River 138-kV line	5
Construct a 138-kV bus at Pleasant Valley Substation to permit second distribution transformer interconnection	5
Expand 345-kV switchyard at Oak Creek to interconnect one new generator (Oak Creek Phase 1)	5
Expand Oak Creek 345-kV switchyard to interconnect one new generator (Oak Creek Phase 2)	5
Replace relaying on 230-kV circuits at Oak Creek	5
Replace two 345-kV circuit breakers at Pleasant Prairie Substation on the Racine and Zion lines with IPO breakers and upgrade relaying	5
Reconductor Oak Creek-Allerton 138-kV line	5
Install second 500 MVA 345/138-kV transformer at Oak Creek Substation	5
Replace CTs at Racine 345-kV Substation	5
Reconductor Oak Creek-Ramsey 138-kV line	5
Loop Ramsey5-Harbor 138-kV line into Norwich and Kansas to form a new line from Ramsey-Norwich and Harbor-Kansas 138-kV lines	5

Table PF-2
*Projects included in the 2014 10-Year Assessment Model**

System additions	Planning zone
Construct 115-kV line from new Woodmin Substation to the Clear Lake Substation	1
Construct a 69-kV line from SW Ripon to the Ripon-Metomen 69-kV line	1
Construct 345-kV line from Rockdale to West Middleton	3
Construct a 345-kV bus and install a 345/138 kV 500 MVA transformer at West Middleton Substation	3
Uprate terminal limitations at McCue for the Y-79 McCue-Milton Lawns 69-kV line	3
Replace two overhead Blount-Ruskin 69-kV lines with one underground 69-kV line	3
Rebuild Y-33 Brodhead to South Monroe 69-kV line	3
Construct EcoMet wind farm and related projects	4
Install 3-75 MVAR capacitor banks at Bluemound Substation	5

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

Table PF-3
Projects included in the 2019 10-Year Assessment Model

System additions	Planning zone
Construct second Shorewood-Humboldt 138-kV underground cable	5

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

Table PF-4
Projects included in the 2024 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*

Table ZS-7: ATC System Angular Stability Assessment for 2009 10-Year Assessment

	Facility Studied	# Units	Total Capacity (MW)	Last Year 0f Detail Study	Response for Selected NERC Category B2, C3 and C8 Outages (NERC Reliability Criteria)				SPS	Note
					2009	2010~2013	2014	Appropriate for 2015~2019		
	Existing Units									
1	Pleasant Prairie	2	1208.0	2007	Acceptable (1, 2, 3)	Acceptable (6)	Acceptable (6)	Yes	Yes	IPO Breakers
2	Paris	4	400.0	2008	Acceptable (2, 3)	Acceptable (2, 3)	Acceptable (2, 3)	Yes	No	
3	Oak Creak	7	1138.0	2007	Acceptable (1, 2, 3)	Acceptable (6)	Acceptable (6)	Yes	No	
4	Valley	2	280.0	2005	Acceptable	Acceptable	Acceptable	Yes	No	See note (4, 5)
5	Germantown	5	345.0	2005	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Yes	No	
6	Port Washington CC1	6	1080.0	2005	Acceptable	Acceptable	Acceptable	Yes	No	See notes (6, 7)
7	Point Beach	2	512; 514	2005	Acceptable (1, 2,3)	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Yes	Yes	
8	Kewaunee	1	579.0	2005	Acceptable	Acceptable	Acceptable	Yes	No	IPO Breakers, See note (8)
9	Edgewater	3	773.0	2005	Acceptable (1, 2,3)	Acceptable (1, 2,3)	Acceptable (1, 2,3)	Yes	Yes	IPO Breakers
10	S. Fond du Lac	4	352.0	2005	Acceptable (1, 2,3)	Acceptable (1, 2,3)	Acceptable (1, 2,3)	Yes	No	
11	Neevin	2	300.0	2005	Acceptable (1, 2,3)	Acceptable (1, 2,3)	Acceptable (1, 2,3)	Yes	No	
12	Skygen	1	185.0	2005	Acceptable (1, 2,3)	Acceptable (1, 2,3)	Acceptable (1, 2,3)	Yes	No	
13	Pulliam	6	459.0	2005	Acceptable (1, 2,3)	Acceptable (1, 2,3)	Acceptable (1, 2,3)	Yes	No	See note (9)
14	West Marinette	4	240.0	2005	Acceptable	Acceptable	Acceptable	Yes	No	See note (10,11)
15	Fox Energy	3	672.3	2008	Acceptable (2, 3)	Acceptable (2, 3)	Acceptable (2, 3)	Yes	No	IPO Breakers
16	Sheboygan Energy	2	343.0	2005	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Yes	No	
17	Cypress	88	145.2	2005	Acceptable	Acceptable	Acceptable	Yes	No	See note (12)
18	Forward Energy Center	86	129.0	2008	Acceptable (2, 3)	Acceptable (2, 3)	Acceptable (2, 3)	Yes	No	
19	Columbia	2	1050.0	2005	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Yes	No	IPO Breakers
20	Christiana	3	544.5	2005	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Yes	No	
21	Riverside	3	659.1	2005	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Yes	No	
22	Rock River	5	262.0	2005	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Yes	No	
23	Nelson Dewey	2	226.0	2005	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Acceptable (1, 2, 3)	Yes	No	
24	University	2	236.0	2008	Acceptable (2, 3)	Acceptable (2, 3)	Acceptable (2, 3)	Yes	No	
25	Concord	4	400.0	2008	Acceptable (2, 3)	Acceptable (2, 3)	Acceptable (2, 3)	Yes	No	
26	West Campus	3	147.2	2005	Acceptable	Acceptable	Acceptable	Yes	No	See note (13)
27	Presque Isle	5	431.0	2007	Acceptable (14)	Acceptable (14)	Acceptable (14)	Yes	Yes	See note (15)
28	Weston	5	552.6	2005	Acceptable (16, 3)	Acceptable (16, 3)	Acceptable (16, 3)	Yes	No	IPO Breakers, See Note (17)
	New / Future Units									
29	Elm Road Phase I	1	650.0	2006	Acceptable (18)	Acceptable (18)	Acceptable (18)	Acceptable (18)	No	IPO Breakers
30	Elm Road Phase II	1	650.0	2006		Acceptable (18)	Acceptable (18)	Acceptable (18)	No	IPO Breakers
31	Green Lake (wind)	108	160.0	2006		Acceptable (19)	Acceptable (19)	Acceptable (19)	No	
32	Bowers Road (wind)	70	105.0	2006		Acceptable (20)	Acceptable (20)	Acceptable (20)	No	
33	EcoMet (wind)	67	100.5	2008		Acceptable (21)	Acceptable (21)	Acceptable (21)	No	

These shaded rows represent units at plants in which there have been a significant system topological change near the plant or significant parameter changes or updates to the dynamic models used in stability studies and are to be studied in the 2009 TYA as part the system angular stability analysis

Notes:

(1) "American Transmission Company (ATCLLC) - 2005 Ten Year Assessment" (http://www.atc10yearplan.com) dated September 2005 section "ZONE & STUDY RESULTS > Multiple outage analysis" under the heading "Generator Stability" and "Voltage Stability" stating the results of dynamics studies for category C.

(2) Comparing 2009 TYA models with 2008 TYA models, no significant change has occurred near the generation station, other than the local load growth. Therefore, the stability results from the 2008 TYA are still applicable and are acceptable in the following years.

(3) "American Transmission Company (ATCLLC) - 2008 Ten Year Assessment" (http://www.atc10yearplan.com) dated October 2008 section "ZONE & STUDY RESULTS > Multiple outage analysis" under the heading "Generator Stability" and "Voltage Stability" stating the results of dynamics

(4) Since the TYA2008 cases there has been replacement of the IEEET1 exciter model with ESST4B on Valley units 1 and 2.

(5) Stability simulations meet NERC requirements for phase-ground fault with delayed clearing, but do not meet ATC requirements for three-phase fault with delayed clearing. Action plan is to replace breaker failure relays with SEL-352 relays on lines 301, 302 and 311 and replace the existing three cycle oil breakers with two cycle gas breakers at positions 314, 321, and 324.

(6) Generator Validation Study Port Washington Generator Facility - MISO #G014 (#36365-01), MISO #G093 (#37004-01), MISO #G510 (#38429-02)" dated September 8, 2008. \\atc.llc\atcdata\Knowledge Share\Planning and Service\Generator Requests\G-T\G_T Projects\Requests in Service\G510 - Port Washington Extra MW\06_As-Built Information\Generator Validation study.

(7) Since the TYA2008 cases there has been replacement of the GAST2A governor model with GGOV1 governor model as part of RFC model standardization project. In addition the 2009 TYA cases have parameter updates for each of the generators in block 1 (POWCTG11, POWSTG10 and POWCTG12).

(8) Since the TYA2008 cases there has been replacement of the IEESGO governor model with USRMDL USIEG2 governor model.

(9) Pulliam units 3 and 4 were removed from service indefinitely as of December 31 2007 decreasing the total capacity to 459 MW.

(10) Area near plant had significant topological system changes that included the addition of the Menominee 138/69 kV transformer and significant re-configuration of 69 kV network between Pioneer, Pound, Sandstone, Crivitz High Falls and Thunder. Also included addition of Wells St-Ogden 69 kV line.

Notes (Continued):

(11) Stability simulations meet NERC requirements for phase-ground fault with delayed clearing, but do not meet ATC requirements for three-phase fault with delayed clearing. System improvements to meet ATC requirements would require replace of circuit breakers and breaker relaying as well as a possible substation reconfiguration that will be factored in with any other system improvements needed in the area. Existing phase-ground fault duty has to nearly double under present clearing times before the NERC requirements are exceeded, which provides an adequate margin in order to planning and implement system improvements needed to meet ATC requirements.

(12) Change in generator model parameters for BlueSky and Greenfield because of change in number of machines from 41 to 44 and in manufacturer plus the addition of a fast response reactive compensation device. Area near plant had significant topological system changes that include addition of the Werner West-Highway 22, Highway 22-Gardner Park, and Highway 22-Morgan 345 kV lines; second Kewaunee transformer; connection of two wind farms totaling 198 MW to the 138 kV system in the area

(13) Area near plant had significant topological system changes that included the conversion of the two Blount-Ruskin 69 kV lines to a single 138 kV, as well as re-configuration of other the 69 kV lines involving the Mendota Substation. In addition, the installation of the North Madison-Huiskamp 138 kV line and loop-in of North Madison-Yahara River 138 kV line into new Vienna.

(14) "Presque Isle Special Protection System “Remedial Action Tripping Scheme” (RATS)" Version 3.0 dated December 17, 2007. http://oasis.midwestiso.org/documents/ATC/PresqueIsleSPS-v3.pdf

(15) Presque Isle units 1 and 2 were retired from service as of January 1 2007. Presque Isle units G3 and G4 are retired as of 12/31/2012. These retirements result in a decreasing the total capacity to 431.

(16) "Generator Interconnection Facility Study Report for G144 - Addendum IV, MISO #G144 (#37187-02)" dated June 16, 2005. \\atc.llc\atcdata\Knowledge Share\Planning and Service\Generator Requests\G_T Projects\G144 - Weston G4\Study Reports\GIC044_Facility_Study_Report.pdf.

(17) "Weston Unit 4 Special Protection System Review Final Draft" Report, dated February 9, 2009. \\atc.llc\atcdata\PSSE\Special_Studies\SPS Studies PSSE2\Weston4 SPS\W4 SPS with HWY22 interim\Report.

(18) "Final Facility Study Update – Revision 2 Phase I, II & III Milwaukee County, Wisconsin MISO #G051 (#36760-01)" dated January 15, 2007. \\atc.llc\atcdata\Knowledge Share\Planning and Service\Generator Requests\G_T Projects\G051 - Elm Road\04_Faciliies Study\Study Reports G051_Facility_Study_p1-3_revision_2_Final-Jan07.doc

(19) "Interconnection System Impact Study Report - Addendum II - MISO #G376 (#37935-03)" dated May 31, 2008. \\atc.llc\atcdata\Knowledge Share\Planning and Service\Generator Requests\G-T\G_T Projects\G376 - Green Lake Wind\03_System Impact Study\Study Reports\G376_Impact_Study.pdf.

(20) "G546 Interconnection System Impact Study Report Revision 2 - MISO #G546 (#38605-01)" dated December 13, 2006. \\atc.llc\atcdata\Knowledge Share\Planning and Service\Generator Requests\G-T\G_T Projects\G546 - Sugar Creek Wind\03_System Impact Study\Study Reports\G546_Impact_Study.pdf.

(21) "Interconnection System Impact Study Report" - MISO #G611 (#38791-01)" dated October 24, 2008. \\atc.llc\atcdata\Knowledge Share\Planning and Service\Generator Requests\G-T\G_T Projects\G611 - EcoMet\03_System Impact Study\Study Reports\G611_Impact_Study.pdf.