2012 10-Year Assessment
www.atc10yearplan.com

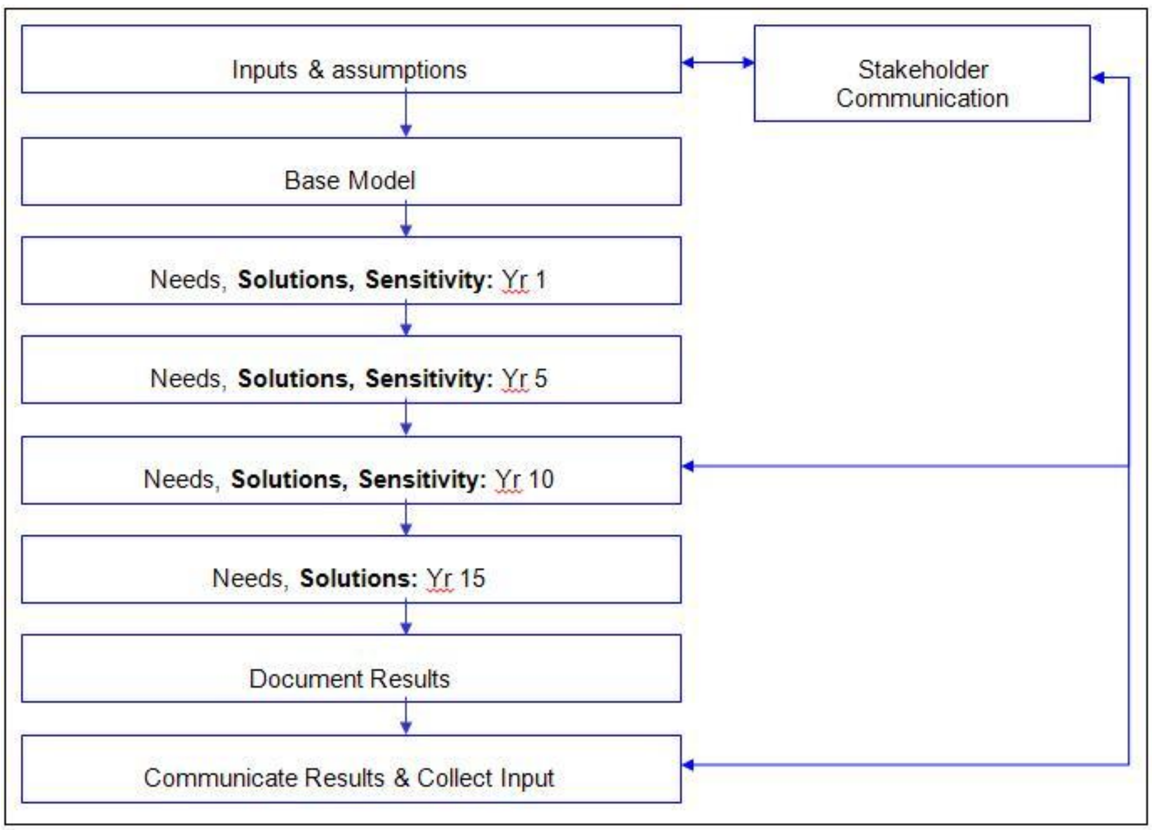
Methodology and Assumptions

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 maximum reactive power capability within ATC's 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 maximum reactive power capability within ATC's footprint. Exceptions to the voltage range criteria apply for certain interconnected entities, and are evaluated in accordance to their signed interconnection agreements. Voltage range exceptions also apply to underground and underwater cables.

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 2012 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 2012 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 2013 and 2017 were selected to meet the 1-5 year horizon. The years 2022 and 2027 were selected to meet the beyond 5 year horizon. A range of system conditions and study years were developed and analyzed for the 2012 Assessment. Steady state peak load models for all four years were created. In order to determine how close ATC generators were to their maximum reactive power output, two additional models were created for each year. The first model for each year studied reduced ATC generator maximum reactive power by 10 percent. These models were utilized to determine generator reactive power output under intact system conditions (TPL-001-0). A second model for each year was created with net maximum reactive power capability 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 limits are exceeded. The criterion we use to determine what these limits should be is provided in Planning criteria).

This 2012 network Assessment was developed in a chronological fashion. Planned transmission additions expected to be in service by June 2013 were included in the 2013 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 2017, 2022 and 2027 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 2021 (in most cases through the year 2027 and one through the year 2020). 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 2022. To obtain a forecast for 2022, certain customer-provided forecasts were extended by growing their load by using a 3-year linear growth rate calculated over the last three years of the forecasts provided by the customer. Load power factors were held at their levels at the last year forecast. Non-scalable loads were also held at their load levels at the last year forecast using this methodology.

The 2027 summer peak load model was developed utilizing similar methodology. To obtain a projection for 2027, customer-provided forecasts were extended by growing their load by using a 3-year linear growth rate calculated over the last three years of the forecasts provided by the customer. Load power factors were held at their levels at the last year forecast. Non-scalable loads were once again held at their load levels at the last year forecast. It should be noted that the loads utilized in the 2027 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 2027 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
2013	13,057	N/A
2017	13,583	0.99% (2013-2017)
2022	14,183	0.87% (2017-2022)
2027	14,801*	0.86% (2022-2027)
Overall		0.89% (2012-2027)

**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.

1.2.2 Model building

1.2.2.a Assumptions common to all models

The following assumptions are common to all models studied in the 10-Year Assessment. Any exceptions are listed within the respective assumption section:

- New Generation
- Generation Retirements
- Cuttoff dates
- Generation Project Schedule
- Generation outside of the System
- Generation Dispatch
- Line and Equipment ratings

- Project Criteria

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 2011 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 2012 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 2012 and 2013 models showed these generators as out of service. The 2017, 2022 and 2027 models have 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 2012 10-Year Assessment models we assumed the following generators were to be out of service (ATC cannot comment on whether these units have completed MISO Attachment Y studies):

Plant Name	***Zone***	***Installed capacity***	***Assumed out of service***
Eagle River Diesels	1	4 MW	Nov 2011
Lakefront #4	4	9 MW	Oct 2011
Lakefront #6	4	22 MW	Oct 2011
Blount 3	3	39 MW	Jan 2012
Blount 4	3	22 MW	Jan 2012
Blount 5	3	28 MW	Jan 2012
Net decrease before 2012		35 MW	
Net decrease after 2012		124 MW	

Please note that recently some of our customer generators reduced their maximum MW 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:

- 2013 models - October 24, 2011
- 2017 models - October 24, 2011
- 2022 models - October 24, 2011
- 2027 models - October 24, 2011

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 2011 and early 2012. 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 2012, 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***
Point Beach #1	4	105 MW	105 MW	Dec 2011
Garden wind farm	2	5.8 MW	5.8 MW	Dec 2011
Glacier Hills wind farm	3	30 MW	30 MW	Dec 2011
Presque Isle #5	2	-5 MW	-5 MW	Jan 2012
Presque Isle #6	2	-5 MW	-5 MW	Jan 2012
Stoney Brook wind farm	4	19.7 MW	19.7 MW	May 2013
Rothschild Biomass	1	50 MW	50 MW	Sept 2013
Net increase by Dec 2012		140.8 MW		
Net increase 2013-2027		59.7 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 2011 Series models. The external system interchange was adjusted from the 2011 MMWG Series models to match the latest ATC members' firm interchange with the exception of the Shoulder 70%, East to West Bias and the West to East Bias models which were built to represent a 3000, 1700 and 700 MW imports into ATC respectively.

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%, West to East Bias and Light Load models.

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 October 2011, nearly 76 percent of all ATC lines and 91 percent of ATC transformers have SELD ratings that have been validated. Additionally, nearly 97 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

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 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 Normal (Category A) Conditions

The load flow models for the 10-Year Assessment are built to include established (pre-contingency) operating procedures to assess system performance under the normal (Category A) conditions as required in the TPL-001-0 Reliability Standard. The relevant operating procedures are generally standing operating procedures that apply for the planning horizon. These procedures include, but are not limited to, normal open points and switched capacitor banks. Normal Open points are assumed to remain normally open in the base cases. Changes in the status of Normally Open points are provided by the system planners that participate in the decision to change the status of a Normally Open point. Switched non-mobile capacitor banks are assumed to be available for use by the system operators, except in the case of planned outages. This availability is represented by modeling these capacitor banks in the discrete adjustment voltage regulating mode. Mobile capacitor banks are modeled in the base case when there is a known date and location in the planning horizon during which the mobile capacitor bank is planned to be in service.

1.2.2.b.2 Planned Maintenance and Construction Outages

The load flow models for the 10-Year Assessment are built to include maintenance and construction outages that are planned to occur in planning horizon. These outages are typically conditions that are expected to last for a period of six months or more. The modeled outages are provided by the system planners that participate in the decision to schedule the maintenance or construction outage.

1.2.2.b.3 Protection Systems

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.

1.2.2.b.4 Control Devices

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

1.2.2.b.5 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 2013, 2017, 2022 and 2027 steady state project deficient summer peak models were developed to evaluate needs, verify findings of the previous year's Assessment, and confirm that previously identified needs will increase over time. The 2022 and 2027 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.6 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 included as well as 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 and will not introduce any new limitations.

1.2.2.b.7 Load, dispatch and interchange profiles

1.2.2.b.7.a Load Sensitivities (2017)

ATC planning explored two sensitivity analyses in our 2012 10-Year Assessment analyses, the minimum (light load) scenario and the west to east bias scenario. The modeling details of these sensitivities are outlined below.

1.2.2.b.7.a.1 Minimum load scenario (2013,2022)

- ATC Load: 5189 MW & 5638 MW respectively

  - 2011 forecast collection, scalable loads reduced to 33% of peak + non-conforming off-peak loads = 40% of Peak load
- Total ATC Generation: 4874 MW & 5,311 MW respectively
- Includes all planned and proposed projects to be in-service by 6/15/2013 & 6/15/2022 respectively
- *Interchange:* Firm interchange only as of 10/24/2011
- *Dispatch:* ATC-wide Merit order as of 10/24/2011
- Mackinac VSC set to the VSC bypass flow as long as it is within +- 70 MW for the 2014+ model years

1.2.2.b.7.a.2 West to East Bias scenario (2017, 2022)

- ATC Load: 9,475 MW & 9,896 MW respectively
  - 2011 forecast collection, scalable loads reduced to 66% + non-scalable loads = 70% of Peak load as drawn from Operations historical data
- Total ATC Generation: 9,160 MW
- Includes all planned and proposed projects to be in-service by 6/15/2017& 6/15/2022 respectively
- *Interchange:* ATC net as provided in Operations data -700 MW
- *Dispatch:* ATC-wide Merit order as of 10/24/2011
- Mackinac VSC set to the VSC bypass flow as long as it is within +- 70 MW
- *Special additions:*
  - Wind generation in the ATC footprint dispatched to 45% of P_{max} as drawn from Operations historical data,
  - Wind generation west of ATC dispatched to 50% as drawn from Operations historical data,
  - Wind Generation south of ATC dispatched to 55% as drawn from Operations historical data,
  - Minnesota-Wisconsin Export interface (MWEX) loaded to 1400 MW
  - Manitoba Hydro Exports set to 1,350 MW
  - All generation increases were modeled to generation reductions south and east of ATC

1.2.2.b.7.b Summer peak (2013, 2017, 2022, 2027)

- We utilized interconnection point load forecasts provided by various distribution companies in 2011 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.
- Mackinac VSC set to the VSC bypass flow as long as it is within +- 70 MW for the 2014+ model years
- Special additions: none

1.2.2.b.7.b.1 Summer peak 95% Q_{Max} (2013, 2017, 2022, 2027)

- We utilized interconnection point load forecasts provided by various distribution companies in 2011 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.
- Mackinac VSC set to the VSC bypass flow as long as it is within +- 70 MW for the 2014+ model years
- Special additions: Generator Q_{Max} reduced to 95%.

1.2.2.b.7.b.2 Summer peak 90% Q_{Max} (2013, 2017, 2022, 2027)

- We utilized interconnection point load forecasts provided by various distribution companies in 2011 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.
- Mackinac VSC set to the VSC bypass flow as long as it is within +- 70 MW for the 2014+ model years
- Special additions: Generator Q_{Max} reduced to 90%.

1.2.2.b.7.c High load model (2017)

- We utilized interconnection point load forecasts provided by various distribution companies in 2011. The 2017 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 2011 Series, 2017 summer model.
- The external system interchange was adjusted from the 2011 MMWG Series 2017 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.
- Mackinac VSC set to the VSC bypass flow as long as it is within +- 70 MW

1.2.2.b.7.d Shoulder 70% models (2017, 2022)

- We utilized interconnection point load forecasts provided by various distribution companies in 2011.
- The 2017 and 2022 shoulder models were created by selectively scaling down loads that generally vary by time-of-day to approximately 66 percent of the summer peak condition to produce an overall 70 percent of summer peak load 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 external system interchange was adjusted from the 2011 MMWG Series 2017 summer interchange to match latest ATC members' firm interchange.
- Mackinac VSC set to the VSC bypass flow as long as it is within +- 70 MW

1.2.2.b.7.e Shoulder 90% models (2017, 2022)

- We utilized interconnection point load forecasts provided by various distribution companies in 2011. The 2017 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.
- Mackinac VSC set to the VSC bypass flow as long as it is within +- 70 MW

1.2.2.b.8 Model years

We started model development for this Assessment by building a system model that represented 2012 summer peak conditions. This 2012 model is referred to as an "as-planned" model because essentially everything in the model is certain to be in service by 2012 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 2012 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 2013 and 2017 were selected to meet the 1-5 year horizon. The years 2022 and 2027 meet the beyond 5 year horizon. The years 2013, 2017 and 2022 were chosen to coordinate with the most recently released MMWG models that were available.

The 2013, 2017, 2022 and 2027 models were developed to evaluate needs, verify findings of the 2011 Assessment, and confirm that previously identified needs will increase over time. The 2022 and 2027 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 assessment models

The base case for the annual generation angular stability review study was a 2016 light load model from the 2011 Assessment models. This model was updated for the latest topology, ratings, load forecasts, generator parameters, and generation dispatch assumptions.

1.2.2.d Short-circuit assessment models

The base case model for the annual short-circuit assessment was the CAPE application equivalent to the transmission planning 2012 'as built' model with maximum generation dispatch. For our studies of new generation interconnections, the base model is modified to include the new facilities and any proposed transmission system modifications. The short-circuit studies are performed 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

1.2.3.a.1 System intact and single contingency simulations

ATC performed system intact and single contingency simulations on the 2013, 2017, 2022 and 2027 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 above .

1.2.3.a.2 Comparison of results vs. Planning Criteria

The models described above are analyzed and compared to our Planning Criteria. Limits that approach or exceed our criteria are then listed in limitations tables.

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 limitations 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 plan to communicate needs and solicit solution development options to our stakeholders earlier in the process.

1.2.3.b Preliminary Solution Development

1.2.3.b.1 New Limitation

If a new limitation is found in the initial screening, the zone planner will take steps to ensure that the limitation is valid, including verification of the power flow model. If the new limitation 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 limitation 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 limitation. After all discussion and collaboration has concluded, the results for all the solution options evaluation are recorded in a project development document.

Cost estimates are developed for solution options that effectively address the identified limitation. After cost information has been obtained, the zone planner selects the most efficient solution option from a cost-benefit standpoint and initiates the project development process by completing the project request form to create a provisional project. Finally, the project request is processed through ATC's Project Approval Process.

1.2.3.b.2 Repeat Limitation

If a previously identified limitation is found in our initial screening, the zone planner will re-verify that existing solution options address that limitation. If an in-service date or scope change is warranted, updated cost estimates are developed. 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 Network Unspecified Project Process

Network Unspecified 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.

A significant amount of dollars were set aside in ATC's capital forecast in order to address Network Unspecified Projects. ATC begins to identify Network Unspecified Projects with internal discussions to determine how to best serve our customers' local and regional needs. In these discussions, we collaboratively determine which potential projects are more likely to be built within the 10-year Assessment period. The cost and potential benefits of the projects are discussed, vetted and approved by our AIM Executive committee. After consensus is reached, the ATC capital forecast is updated to include these Network Unspecified Project 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 2013, 2017, 2022 and 2027 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 effect 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 2011 Assessment, this year we attempted to address the first two questions. We built year 2013, 2017, 2022 and year 2027 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.

1.2.4 Special Review and Analyses

1.2.4.a Multiple Outage Review and Analysis

ATC performs a comprehensive evaluation of each applicable NERC Category C and Category D type outage on either an annual schedule, a rolling periodic schedule, or interconnection study specific schedule.

Category C Outages
ATC performs a comprehensive screening of each applicable NERC Category C type outage on a five year rolling schedule. ATC performs an assessment of all of the Category C1 through C9 events, except the Category C4 events. Category C4 contingency events do not apply to ATC because there are no HVDC facilities in the ATC system.

Category D Outages
ATC performs a sufficient assessment of each applicable Category D type outage on an annual schedule, a rolling periodic schedule, or interconnection study specific schedule.

With respect to each category of Category D extreme events analyses, ATC does the following:

- For Category D1 through D5, steady state and dynamic simulations are performed for these events whenever generation interconnection studies are requested and completed.
- For Category D6 through D10, steady state simulations are performed on a three year rolling schedule
- For Category D11, ATC understands “a large load or major load center” to be either a single 100 kV and above end-use customer interconnected at one substation with 300 MW or more of load (i.e. “large load”) or an area served by only two or three circuits at 100 kV and above that has 300 MW or more of load (i.e. “major load center”). ATC does not have any large loads or major load centers that meet these definitions. Therefore, no Category D11 analysis is required.
- For Category D12 and D13, ATC performs an assessment of each Special Protection System in accordance with the MRO and RFC procedures for implementing PRC-012 and PRC-014 for review by the applicable Regional Entity. These reviews include an assessment of the BES performance without the Special Protection System installed, which replicates a D12 contingency. These reviews also include an assessment of the BES performance for the inadvertent operation of the Special Protection System, which replicates a D13 contingency.
- For Category D14, both MRO and RFC have performed analysis of severe power system disturbances for actual system events (e.g., September 2008 initiating event

in MRO). These analyses have not identified a significant impact on the ATC system under these severe disturbances. Therefore, severe power swings or oscillations in another Regional Entity beyond the MRO and RFC will have an even less significant impact on the ATC system.

1.2.4.b System Stability Review and Analysis

ATC generally investigates three type of system stability - steady state voltage stability, dynamic voltage stability and dynamic angular (e.g. generator) stability.

The specific system performance criteria that are used to assess each type of system stability are given in the ATC Planning Criteria.

Steady State Voltage Stability

The steady state voltage stability analysis is performed on a specific area of the ATC system when general steady state analysis indicates areas of very low voltage or voltage collapse (non-convergent simulations) for NERC TPL-002 or TPL-003 reliability standard requirement contingencies in the near or longer term planning horizons. Additionally, each angular stability study performed by ATC screens the system for voltage stability issues through the application of the ATC voltage recovery criteria described in ATC's Planning Criteria. If steady state or dynamic analyses identifies areas of weakness indicative of voltage instability, further examination of system characteristics and, possibly, more detailed analysis will be performed. This more detailed analysis may include replacement of lumped load modeling with more specific dynamic modeling of the distribution system and its loads.

Dynamic Voltage Stability

The dynamic voltage stability analysis is performed on a specific area of the ATC system when general steady state analysis indicates areas of very low voltage or voltage collapse (non-convergent simulations) for NERC TPL-002 or TPL-003 reliability standard requirement contingencies in the near or longer term planning horizons. Dynamic voltage stability analysis can reveal results where the voltage at some buses will collapse and not recover to acceptable values found be steady state analysis, which assumes that system "rides through" the dynamic recovery period.

Dynamic voltage stability analysis is assessed for any new or revised generation interconnection facilities before they are placed in service.

When dynamic analysis is performed and there is not a large stability margin, then normal load modeling is replaced with more specific, and generally conservative, dynamic load modeling. Very large loads may be modeled with specific dynamic models and the remaining loads are modeled with using lumped dynamic load models that depend on the percentage of industrial, commercial and residential load at each distribution load interconnection point.

Dynamic Angular (Generator) Stability

The dynamic angular stability of all major generation facilities in the ATC system is assessed on a five year rotation. Generation facilities may be assessed in less than five years, if there are significant changes to the generator exciter, the generator governor, a power system stabilizer, the generator step up transformer, or nearby system topology. In addition, dynamic angular stability is assessed for any new generation facility before it is placed in service.

Generation facilities with a total net output above 100 MW and associated transmission lines operating usually above 100 kV are normally selected for system angular stability assessment. The methodology used in assessing the major generator stations includes:

1. A review to determine that no significant system topological changes have occurred near the generator stations other than local load growth.
2. A review of the parameter values and the model types used in representing the dynamic response of units at the generator stations in system angular stability simulations to determine that no significant changes have occurred.
3. A review of the date of the last stability study conducted for each of the major generator stations to determine that the elapsed time does not exceed 5 years.

The assessments take into account applicable simulation requirements and performance requirements in the NERC TPL-002, TPL-003 and TPL-004 reliability standards, as well as the ATC dynamic performance criteria, which cover compliance with the TPL-503-MRO-1 reliability standard requirements.

ATC observes a minimum ½ cycle margin between the Maximum Expected Clearing Time (MECT) and Critical Clearing Times (CCT) that lead to unacceptable system instability.

Small Signal Stability

Since no previous studies have found any small signal instability situations in the ATC system and the MRO recently retired its small signal stability standard, not small signal stability assessment was performed this year. However, ATC's transient stability damping criteria will continue to be used as screening tool to determine whether any new small signal stability studies should be performed.

1.2.5 Documentation

1.2.5.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 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 is printed, and distributed. The Summary Report and additional details are posted at www.atc10yearplan.com.

Table PF-1

Projects included in the 2013 10-Year Assessment Model

System additions	Planning zone
Woodmin T-D interconnection	1
Omro-Winneconne asset management uprate	1
Chandler second 138/69-kV transformer	2
J060 G-T interconnection	2
Delta capacitor size change	2
Nine Mile-Roberts asset management uprate	2
Indian Lake-Hiawatha 138/69 LTC	2
Chalk Hills 138/69-kV transformer replacement	2
Engadine Load relocation	2
Hoerner Tap retirement	2
Mount Horeb-Verona rerate	3
Gran Grae-Boscobel asset management project	3
Brodhead-South Monroe 69-kV line rebuild	3
Darlington-Jennings asset management uprate	3
Sycamore-East Town undergroud cable uprate	3
Uprate Fitchburg-Nine Springs 69-kV and Royster-Pflaum 69-kV lines and move AGA load to the Royster-Femrite 69-kV line	3
Mendota Substation retirement	3
Walnut distribution capacitor bank	3
Rockdale-Cardinal 345-kV line	3
Blount distribution capacitor bank retirement	3
Jefferson distribution capacitor bank retirement	3
Glacier Hills G706/H012 G-T interconnection and associated uprates	3
Y-25 asset management uprate	3
Y-159 asset management uprate	3
Y-8 asset management rebuild	3
Beloit Gateway T-D interconnection	3
Fountain Prairie T-D interconnection	3
Y-20 asset management rebuild	3
Schofield T-D interconnection	3
796L41 asset management uprate	4
G834-J023 G-T interconnections	4
Point Beach GSU	4
C-103 asset mangement uprate	4
C-55 asset management uprate	4
X-50 asset management uprate	4
Canal-Dunn Road 138-kV line project	4
Sunset Point-Pearl Avenue rebuild	4
I-113 asset management uprate	4
Forest Avenue T-D interconnection	4
Forest Jct-Lake Park and Forest Jct-Kaukauna Tap asset manangement uprates	4
Rapids T-D interconnection	4
Little Suamico T-D interconnection	4
G590 G-T interconnection	4
Tosa-Granville-Butler 138-kV line uprate	5
Bluemound transformer replacement	5
Bluemound-Tosa asset management uprate	5

Table PF-1

Projects included in the 2013 10-Year Assessment Model

System additions	Planning zone
Oak Creek-Bluemound asset management rerate	5
Riverbend T-D interconnection	5
Pleasant Prairie Substation rebuild	5

Table PF-2

*Projects included in the 2017 10-Year Assessment Model**

System additions	Planning zone
J040 G-T interconnection	1
Council Creek-Petenwell line uprate	1
Construct Monroe County-Council Creek 161-kV line and Timberwolf 69-kV switching station	1
Ripon capacitor bank	1
Petenwell transformer replacement	1
Metomen transformer replacement	1
Energize Indian Lake-Hiawatha 138-kV line	2
Straits flow control project	2
Arnold transformer	2
Chandler-Old Mead Rd 138/69kV double circuit lines	2
Pine River-Straits rebuild	2
Pine River-9 Mile uprate	2
Vinburn T-D interconnection	3
Hawk T-D interconnection	3
West Middleton T7 T-D interconnection	3
J084 G-T interconnection	3
Edgewater transformer replacements	4
Construct ring bus at 96th St. Substation	5
Pleasant Prairie-Zion Energy Center 345-kV line	5
St. Lawrence-Hartford asset management rebuild	5
Milwaukee County T-D interconnection	5
Concord-Cooney asset management rebuild	5
Hartford-Butler Ridge asset management rebuild	5
Rubicon-Butler Ridge asset management rebuild	5
Rubicon-Concord asset management rebuild	5
Paris-Albers asset management rebuild	5
Arcadian-Waukesha rebuild	5
Center third transformer T-D interconnection	5
Mukwanago-Edgewood-St. Martins asset management rebuild	5

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

Table PF-3

*Projects included in the 2022 10-Year Assessment Model**

System additions	Planning zone
Badger Coulee: Cardinal-North Madison-La Crosse County area 345-kV project	3
G8334-J0223 G-T interconnection/Barnhart-Branch River project	4

**Projects included in addition to those listed in Table PF-2*

Table PF-4

*Projects included in the 2027 10-Year Assessment Model**

System additions	Planning zone
None	

**Projects included in addition to those listed in Table PF-2*

Figure PR-9
Generation Interconnection Requests
as of 7/1/12