2016 10-Year Assessment
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Methodology and Assumptions

1.1 Overview

These sections describe the process we used to perform a network assessment of the ATC transmission system. The description includes study assumptions, methods and techniques we used to analyze our transmission network for planning criteria limitations and how we shared results for the 2016 10-Year Assessment. Economic, regional, and asset management planning processes are covered at other locations on the ATC website, www.atc10yearplan.com.

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. ATC meets with stakeholders to discuss assumptions and results. ATC's network planning process is summarized in Figure 1.

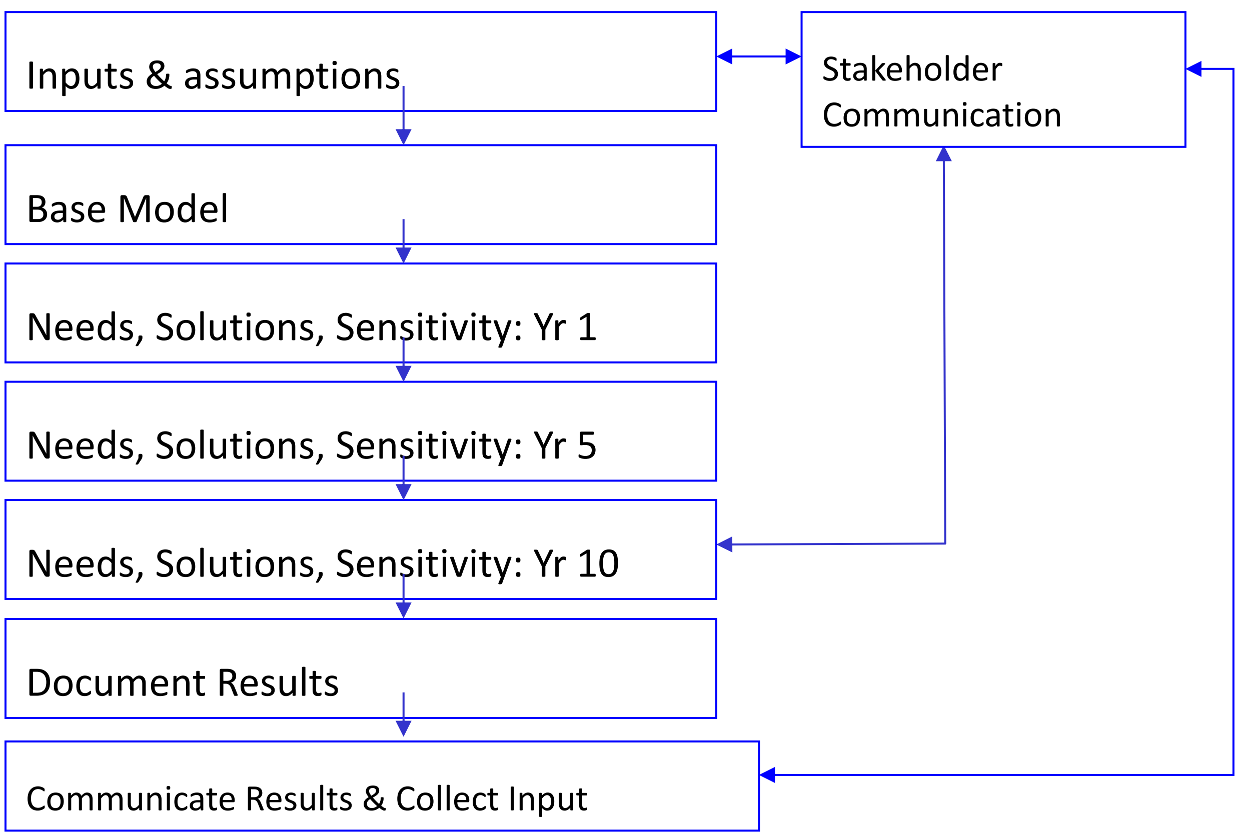

Figure 1: 10-Year Assessment Process

Stakeholder Engagement Process

ATC has developed a stakeholder engagement process that we use to obtain stakeholder input for developing our needs, solutions, and Assessment. More discussion of the process can be found on the stakeholder engagement process page in the “About” menu of the www.atc10yearplan.com website.

Analysis Introduction

Included in the following sections is a discussion of assumptions and methods for the years ATC simulated to satisfy near-term (1 – 5 year horizon) and long-term (5 year and beyond horizon) NERC transmission system assessment standards. Also included is discussion of 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; and 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. ATC not only uses these models to identify where constraints or system limitations may exist, but we also used these models to test the robustness of potential system reinforcements. System limitations were identified for NERC Categories P0 through P7 conditions using the ATC Transmission System Planning Criteria.

The system performance analyses represented in this Assessment included steady state power flow analyses and stability simulations. Multiple outage impacts, economic planning evaluations, generator interconnection impacts, distribution interconnection impacts, and asset renewal plans were also gathered to complete the assessment.

1.2 Network Assessment Methodology

American Transmission Company’s 2016 10-Year Assessment provides current results of planning activities and analyses of the ATC transmission facilities. These activities and analyses identify needs to improve the transmission system performance 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 Attachment FF-ATCLLC in the MISO tariff’s Attachment FF describes ATC’s open planning processes.

The information in this report provides further foundation for continued public discussions of 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 2016 network Assessment analyses were selected in order to meet NERC requirements. The years 2017 and 2021 were selected to meet the near-term (1-5 year horizon). The year 2026 was selected to meet the long-term (beyond 5 year horizon). A range of system conditions and study years were developed and analyzed for the 2016 Assessment. Steady state peak load models for all three years were created. In order to address uncertainty in reactive power capability and preserve some margin for the ATC area, an additional model was created for each year. For each of the additional models the maximum lagging and leading reactive power capabilities were reduced by 10 percent for appropriate generators within the ATC footprint. These reduced reactive capability models were used for both intact system and contingency analyses.

System needs were determined by identifying facilities whose normal or emergency limits are exceeded. The criteria we used to determine these limits are provided in the ATC Transmission System Planning Criteria.

This assessment was developed in a chronological fashion. To start only planned transmission additions expected to be in service by June 2017 were included in the 2017 model, as listed in the Table PF-1. These projects and projects under construction, or with an application filed to construct, or with an application being prepared were included in the 2021 and 2026 models as appropriate based on projected in service dates (See Tables PF-1, PF-2 and PF-3). Once needs were reconfirmed or identified and solutions were reconfirmed or identified, then solutions were added to the models to confirm limitations have been removed.

1.2.1 Load Forecast

Steady state summer peak models were 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. In 2015, customer load forecasts were gathered for all ATC customers, at least through the year 2025 (in most cases, through the year 2031). The forecasts were compared to historic data and previous load forecasts to check validity and consistency. Once questions were resolved with the customer, the final forecast information was sent back to the customers as confirmation. Then the data was incorporated into our models.

Some customers did not provide an 11th-year load forecast for the studied year 2026. In these instances the forecast for 2026 was obtained 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 and non-scalable loads were held at levels in the last forecast year provided.

In the event ATC or MISO planning processes required a 15th year load projection, a similar methodology was utilized to obtain a projection for 2031. Customer-provided forecasts were extended by growing their load by using a linear annual growth rate calculated over the last three years of the forecasts provided by the customer. Load power factors and non-scalable loads were held at levels in the last forecast year provided.

ATC summer peak total load projections (MW)

Year	Load (MW)	Study period compounded growth rate
2016	13,147	Not applicable
2017	13,263	Not applicable
2021	13,617	0.71% (2016-2021)
2026	14,035	0.61% (2021-2026)
2031	14,456	0.59% (2026-2031)
Overall		0.63% (2016-2031)

ATC worked with the distribution companies as much as possible to confirm forecast variations from past historic and past forecast trends.

1.2.2 Model Building

1.2.2.a Assumptions Common to all Steady State Models

The following subsections contain assumptions that are common to all steady state models studied in the 10-Year Assessment.

- New Generation
- Generation Retirements
- Cutoff Dates for Model Modifications
- Generation Project Schedule
- Generation Outside of the System
- Generation Dispatch
- Line and Equipment ratings
- Project Criteria

Following the assumptions common to all models, in section 1.2.2.b, additional common assumptions and the specific models created are discussed.

1.2.2.a.1 New Generation

There have been generation projects proposed within the ATC service territory. Many of these proposed projects have interconnection studies completed and a few have had transmission service facility studies completed. Some have proceeded to or through the licensing phase and one or more are under construction. There are also proposed generation projects that have dropped out of the MISO generation queue (refer to Appendix A, Generation Interconnections), adding uncertainty to the transmission planning process. Given this uncertainty we have adopted a criterion to establish which proposed generation projects would be included in the 2016 Assessment models.

In the 2016 10-Year Assessment, the criterion was broken into two time frames, years 1 through 5 and beyond 6 years into the future.

1. For in service dates in years 1 through 5, only those generators with FERC approved interconnection agreements will be included in the planning models.
2. For in service dates in 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.

1.2.2.a.2 Generation Retirements

Generators connected to the ATC transmission system may be retired or mothballed. Our criteria to determine when generators should no longer be included in our 10-Year Assessment models requires a completed MISO Attachment Y study. When this is true 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 candidates for retirement. Using the disconnection criteria above, in the 2016 10-Year Assessment we assumed the following generators were out of service.

ATC modeled the following generators out of service

Plant Name	Zone	Installed capacity	Assumed out of service
Escanaba #1	2	12.67 MW	12.67 MW
Escanaba #2	2	12.45 MW	12.45 MW
Escanaba #3	2	13.13 MW	13.13 MW
Total decrease after 2015		38.25 MW	38.25 MW

1.2.2.a.3 Cutoff Dates for Model Modifications

- 2017 models – December 28, 2015
- 2021 models – December 28, 2015
- 2026 models – December 28, 2015

1.2.2.a.4 Generation Projects Schedule

To maintain the schedule needed to complete this Assessment, the models were developed during late 2015 and early 2016. 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 2016, the criterion above resulted in the following proposed generation projects being included in the applicable power flow models.

Proposed generation projects being included in the applicable power flow models

Plant Name	Zone	Installed capacity increase	Dispatched increase	Assumed in-service
Garden wind farm	2	13.4 MW	13.4 MW	Dec 2016
Twin Falls Hydro	2	3.7 MW	0.5 MW	Jul 2016
Net increase by Dec 2016		17.1 MW		
Net increase 2017-2031		0 MW		

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

1.2.2.a.5 Generation Outside of the ATC System and Interchange

The model for the system external to ATC was taken from the most appropriate model included in the 2015 MMWG Series models. The external system interchange was adjusted from the 2015 MMWG Series models to match the latest ATC members' firm interchange.

1.2.2.a.6 Generation Dispatch

Balancing Authority area generation was dispatched based on economic dispatch for that Balancing Authority with the exception of the 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).

1.2.2.a.8 Project Criteria

The steady state models built for the 2016 10-Year 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-3 for projects that were included in the analyses.

1.2.2.b Additional Common Assumptions and Specific Steady State Power Flow Models

1.2.2.b.1 Normal (Category P0) Conditions (Common Assumption)

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 (P0) conditions as required in the TPL-001-4 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 (Common Assumption)
The load flow models for the 10-Year Assessment are built to include maintenance and construction outages that are planned to occur in the planning horizon. The only outages modeled are typically conditions that are expected to last for a period of six months or more. The modeled outages are obtained from ATC's Transmission Outage Application.

1.2.2.b.3 Protection Systems (Common Assumption)
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. In the steady state simulations, we simulated event based contingencies that reflect all of the elements that would be removed by the existing or planned protection system. Dynamic studies, in particular, simulate protection system operating times, associated breaker clearing times, and backup device tripping functionality.

1.2.2.b.4 Control Devices (Common Assumption)

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, SVCs and back-to-back HVDC (VSC) power flow controllers.

1.2.2.b.5 Project Deficient Models
The load flow models built for the 10-Year Assessment are 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 2017, 2021, and 2026 steady state project deficient summer peak models were developed to evaluate needs, verify Assessment findings of the previous years, and confirm that previously identified needs will increase over time. The 2026 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 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. The provisional projects included are needed to address system limitations found in the ten year planning horizon, that were not addressed by proposed and planned projects. These models are more indicative of the expected system configurations for the three study years than "Project Deficient" models. The "All Project" models are more likely to reflect the projects ATC includes in regional models. As part of the 10-Year Assessment, contingency analyses are performed on each of the "All Project" models. These analyses will verify whether the planned, proposed and provisional projects included in the models 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 Models of Expected Load Range

1.2.2.b.7.a.1 Summer Peak (2017, 2021, and 2026)

- We utilized interconnection point load forecasts provided by various distribution companies in 2015 for both real and reactive power components of load. Please refer to the Section 4.2.1, Load Forecast, for further details.
- Only firm (latest MMWG plus recent changes) interchange was included in the analyses.
- Mackinac VSC set to the 20 MW north to south operating point.

1.2.2.b.7.a.2 Summer Peak 90% QMax/Qmin (2017, 2021, and 2026)

- We utilized interconnection point load forecasts provided by various distribution companies in 2015 for both real and reactive power components of load. Please refer to the Section 4.2.1, Load Forecast, for further details.
- Only firm interchange was included in our analyses.
- Mackinac VSC set to the 20 MW north to south operating point.
- Special additions: Generator QMax/Qmin reduced to 90%.

1.2.2.b.7.a.3 Shoulder Models (2021 and 2026)

- We started with the summer peak interconnection point load forecasts provided by various distribution companies in 2015.
- To develop shoulder loads, scalable loads in Zone 2, northern Zone 4, and the remainder of the ATC system were reduced such that when non-scalable loads were reset to the LDC provided shoulder load levels as follows. The overall Zone 2 load was modeled at 90% of summer peak, northern Zone 4 was modeled at 80% of summer peak, and the remainder of the ATC system load level was modeled at 70% of summer peak. These load levels were chosen for the shoulder models based on historical data because they are the load levels where maintenance may occur. However, it is recognized that loads at individual points will vary under real-time shoulder conditions.
- The external system interchange for the 2021 shoulder model was adjusted from the 2015 MMWG Series 2021 light load to match latest ATC members' firm interchange. The external system interchange for the 2026 shoulder model was adjusted from the 2015 MMWG series 2021 summer peak interchange to match latest ATC members' firm interchange.
- Mackinac VSC set to the 20 MW north to south operating point.
- Special additions: Generator QMax/Qmin reduced to 90%.

1.2.2.b.7.b Models of Load Sensitivities

1.2.2.b.7.b.1 High Load Scenario (2026)

- ATC Load: 14,866 MW.
- 2015 load forecast utilized.
- Scalable loads were increased such that when non-scalable loads were reset to the LDC provided peak load levels, the overall ATC system load was modeled at a level determined by a probabilistic 90/10 forecast. For the 2016 assessment, the increase was 105.1%.
- Total ATC Generation: 14,802 MW in project deficient model and 14,827 MW in all project model.
- Includes all planned and proposed projects to be in-service by 6/15/2026.
- Interchange: Firm interchange + internal ATC member transactions + external transactions from ATC members to Commonwealth Edison and Xcel Energy were included in the analyses to cover load.
- Dispatch: Merit order by control area as of 12/28/2015.
- Mackinac VSC set to the 20 MW north to south operating point.
- Special additions: Generator QMax/Qmin reduced to 90%.

1.2.2.b.7.b.2 Minimum Load Scenario (2017 and 2021)

- ATC Load: 5,361 MW and 5,503 MW, respectively.

- 2015 forecast collection, scalable loads reduced to 33% of peak + non-conforming off-peak loads = 40% of Peak load.
- Increased power factor of loads based on historical data.
- Total ATC Generation: 5,273 MW and 5,407 MW, respectively.
- Includes all planned and proposed projects to be in-service by 6/15/2017 and 6/15/2021, respectively.
- Interchange: Firm interchange only as of 12/28/2015.
- Dispatch: ATC-wide Merit order as of 12/28/2015.
- Mackinac VSC set to the 20 MW north to south operating point.
- Special additions: Generator QMax/Qmin reduced to 90%, 2021 model includes all planned and proposed ATC projects at the 345 kV level.
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1.2.2.b.8 Model Years

Computer simulation model years for the 2016 network Assessment analyses were selected to meet NERC requirements for a near-term and long-term transmission planning horizon. The years 2017 and 2021 were selected to meet the near-term transmission planning horizon. The year 2026 meets the long-term transmission planning horizon. The years 2017, 2021 and 2026 were chosen to coordinate with the most recently released MMWG models that were available.

The 2016, 2021, and 2026 models were developed to evaluate needs, verify findings of the 2015 Assessment, and confirm that identified needs remain or will increase over time. The 2026 model reflects conditions far enough in the future 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 the long-term transmission planning horizon.

1.2.2.c Dynamic Stability Assessment Models

The process for performing dynamic stability assessments includes three types of analyses: (1) the annual review of existing generator angular stability, (2) specific generator interconnection study reports, and (3) specific voltage stability assessments.

The base cases for the annual review of existing generation angular stability for this compliance monitor period are a 2020 light load model with high local generation, 2020 light load model with low local generation, a 2020 peak load model with high local generation, and a 2020 peak load model with low local generation. All of the base cases were created using the 2014 series MMWG 2020 models.

The base cases for specific generator interconnect study reports are described in detail in the associated study report.

The base cases for specific voltage stability assessments are described in detail within the associated study report.

1.2.2.d Short-Circuit Assessment Models

The base case model for the annual short-circuit assessment was the ATC Near-Term Planning Horizon CAPE scenario. On an annual basis, the addition of near-term planning horizon transmission modifications are modeled in CAPE and the current interrupting capability for existing ATC BES circuit breakers and circuit switchers, used to interrupt fault current, are modeled in CAPE. The current interrupting capability is compared to the expected short circuit fault current using 3-phase and line-ground short circuit fault simulations. Mitigation plans are developed where short circuit fault current sufficiently exceed the device current interrupting capability. For our studies of new interconnections, the base model is an as-built CAPE scenario. Interconnection studies modify the as-built CAPE base case to include the new interconnected facilities and any proposed transmission system modifications.

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 No Load Loss Allowed Contingency Simulations

ATC performed system intact and no load loss allowed contingency simulations on the 2017, 2021, and 2026 models. No load loss allowed contingency simulations included all contingencies that do not allow interruption of firm transmission service or non-consequential load loss, as described in the NERC TPL-001-4 standard, as well as P1 contingencies at the 69-kV level. We ran these simulations for all of the steady state models described above.

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

The models described above are analyzed and compared to the ATC Transmission System Planning Criteria. Limits that approach or exceed our criteria are then listed in a limitations table.

1.2.3.a.3 Reconciliation of Significant Changes to Power Flow Results

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

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.

Cost estimates are developed for one or more solution options that effectively address the identified limitations. After cost information has been obtained, the zone planner initiates the project development process by completing the project request 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 is then updated with the revised in-service date, cost, scope and/or justification. The updated project request is then resubmitted through ATC's project approval process.

1.2.3.b.3 Network Unspecified Network Project Process

Unspecified projects are defined as those projects which may shift into the 10-year timeframe. Unspecified projects can be the result of the following reasons.

- Changing load forecast.
- Changes in generation and distribution interconnection projects.
- Changes in public policy requirements.
- 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 project are discussed, vetted and approved by our executives. 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 project deficient analysis is completed, models are built that include all planned, proposed as well as the majority of the provisional projects. The provisional projects included are needed to address system limitations found in the ten year planning horizon, that were not addressed by proposed and planned projects. These models are called “All Projects” models and are more indicative of the expected system configurations for the 2017, 2021, and 2026 study years.

As part of the 10-Year Assessment, contingency analysis is performed on each of the “All Projects” models. The contingency analysis includes all no load loss allowed contingencies, as described in section 1.2.3.a.1. The analysis will verify whether the planned, proposed, and provisional projects included in the models will resolve issues revealed in the Assessment process.

This “All Projects” analysis assesses the list of reinforcements that are beginning to define our reinforcement plan. The following are three important questions regarding this plan.

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

We attempt to address the first two questions, in our 10-Year Assessment. “All Project” models built for years 2017, 2021, and 2026 include projects identified in the project tables for this Assessment observing specific in-service dates. In the spirit of TPL Standard, Table I, “no load loss allowed” contingency analysis was performed on these models, including selected contingencies in neighboring systems. This analysis showed that no additional reinforcements were needed. The third question is addressed during our detailed project development process.

1.2.4 Other Studies

1.2.4.a Multiple Element Outage Review and Analysis

ATC performs a comprehensive steady state evaluation of the applicable multiple element outage type planning events and extreme events in the NERC TPL-004-1 Reliability Standard. These evaluations are performed on either an annual schedule, a rolling periodic schedule, or interconnection study specific schedule. Multiple element outage contingencies with “load loss allowed” are covered in this section.

<u>*Category P2 - P7 Outages*</u>
Generally, ATC performs a comprehensive analysis of each applicable “load loss allowed” NERC Category P2 - P7 multiple element outage in the ATC system on a three year cycle. There are presently no DC lines in the ATC system. Therefore, no P3.5, P6.4 and P7.2

contingencies are performed. The assessment of contingencies outside of the ATC system are based on MISO's annual MTEP reliability analyses.

Category E Outages
Generally, ATC performs a comprehensive analysis of each applicable Category E extreme events in the ATC system on a three year cycle. The assessment of contingencies outside of the ATC system are based on MISO's annual MTEP reliability analyses.

1.2.4.b System Stability Review and Analysis

ATC generally investigates three types 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 the transmission system for each type of system stability are given in the ATC Transmission System Planning Criteria.

Steady State Voltage Stability
The steady state voltage stability analysis (e.g. P-V Curve simulation) is performed on a specific area of the ATC system when general steady state analysis indicates areas of very low voltage or potential voltage collapse (non-convergent simulations) for NERC TPL-001-4 reliability standard contingencies in the near or long term planning horizons. Additionally, each dynamic study performed by ATC screens for voltage stability issues through the application of the ATC voltage recovery criteria described in the ATC Transmission System Planning Criteria. If general 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.

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 potential voltage collapse (non-convergent simulations) for NERC TPL-001-4 reliability standard 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 the acceptable values found in steady state analysis. Steady state analysis assumes that the 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, 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, agricultural and residential load at each 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-001-4 reliability standards, as well as the ATC dynamic performance criteria.

ATC observes a ½ cycle margin required for tested generator data and a 1 cycle margin required for planned generator data. These margins are observed 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, no small signal stability assessment was performed this year.

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, demographics, asset renewal and economics information from other ATC departments.

- Drafts of text, figures and tables are compiled for peer review.
- A summary presentation of Assessment information is reviewed and approved by ATC management.
- CEII information is documented in a separate electronic document with restricted distribution

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.