NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Potential Reliability Impacts of EPA's Clean Power Plan

Phase II

May 2016

RELIABILITY | ACCOUNTABILITY

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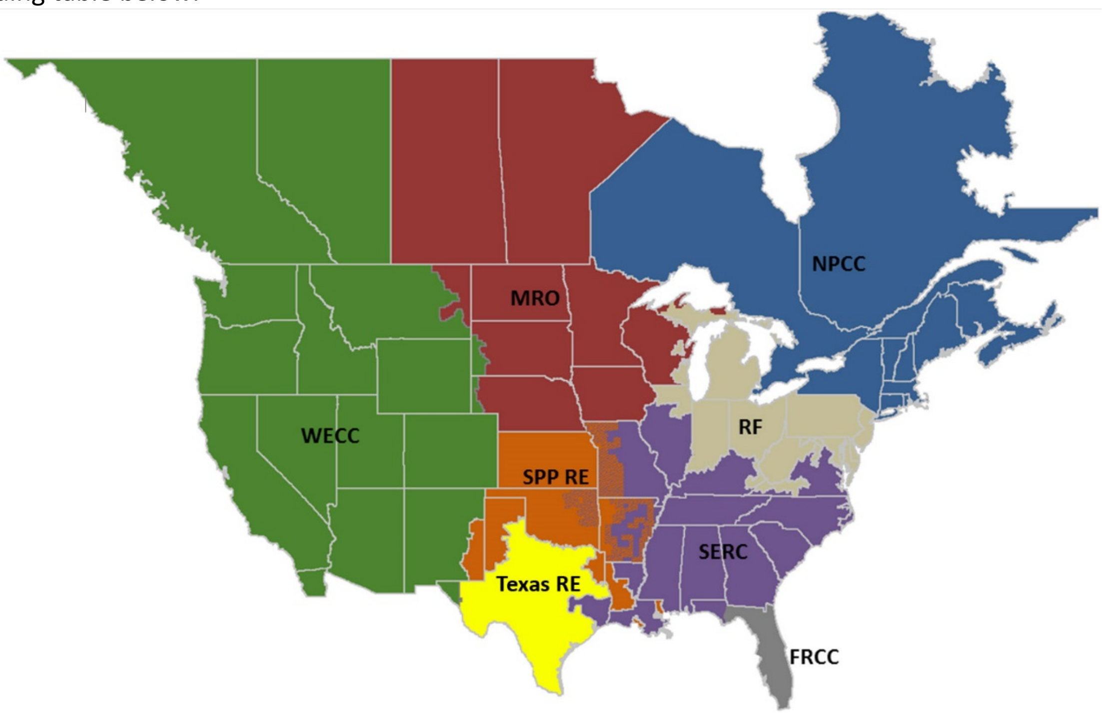
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight Regional Entity (RE) boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

In its role as the Electric Reliability Organization in the United States, NERC has responsibility under Section 215 of the Federal Power Act to conduct periodic assessments of the reliability and adequacy of the nation's bulk power system (BPS), the networked system of high-voltage transmission and generation (as opposed to local distribution facilities). NERC's main focus is BPS reliability and assuring that the reliability of the BPS will be maintained in the future. NERC fulfills its responsibility through detailed engineering analyses and assessments that evaluate reliability risks resulting from various possible future conditions. NERC's assessments provide a technical platform for important policy discussions on reliability challenges facing the interconnected North American BPS. As emerging risks and potential impacts to reliability are identified, special assessments are conducted that provide insights and recommendations for maintaining and considering reliability.

NERC applies a reliability-centered focus on the potential implications of environmental regulations, and other shifts in policy, that can potentially impact the reliability of the BPS. Reliability assessments conducted around the Clean Power Plan (CPP) final rule can inform regulators, state officials, public utility commissioners, electric industry leaders, and other stakeholders of potential challenges to BPS reliability.

This report represents NERC's Phase II Special Reliability Assessment on the Environmental Protection Agency (EPA) CPP final rule. This study assumes that the CPP will be implemented as outlined in the final rule. NERC is aware there are legal reviews underway, but for purpose of this study, the rule is assumed to be implemented. While the report is titled *Potential Reliability Impacts of EPA's Clean Power Plan*, many of the drivers for resource changes are external economic factors or technological developments. The modeling undertaken has limitations and is indicative only; it provides estimates of what resources are likely to be pursued when a number of other constraints are considered. Actual planning, particularly around transmission and upstream natural gas pipelines, will have to be conducted subsequent to this report.

This assessment and its findings do not: (1) advocate a policy position in regard to the environmental objectives of the CPP; (2) promote any specific compliance approach; (3) advocate any policy position for a utility, generation facility owner, or other organization to adopt as part of compliance, reliability, or planning responsibilities; (4) support the policy goals of any particular stakeholder or interests of any particular organization; (5) represent a final and conclusive reliability assessment; or (6) represent an actual system expansion plan.

Objectives

The objectives of this special assessment are to:

- Provide an independent assessment of reliability that informs those engaged in policy discussions on potential risks to BPS reliability and related emerging issues as well as identify measures to mitigate these risks.
- Provide a range of resource adequacy evaluations based on several potential cases using different models to assess possible outcomes.
- Provide a framework for evaluating the more granular regional and localized studies being conducted by Regional Entities, independent system operators (ISOs)/regional transmission organizations (RTOs), utilities, and state organizations using consensus inputs and comparable cases.

Key Findings

The following key findings are components of NERC's overall reliability assessment and are based on the analysis results from comprehensive dispatch modeling:

- **Consistent with NERC's Initial Reliability Review and Phase I report on the CPP, the CPP is expected to accelerate a fundamental change in the electricity generation mix in the United States and transform grid-level reliability services, diversity, and flexibility**. By 2030, coal capacity is expected to decline by up to 27 GW as a direct result of the CPP; renewable capacity, primarily wind and solar, will increase by approximately 10 to 20 GW as a direct result of the CPP; natural gas capacity will experience significant growth between now and 2030, but remains relatively flat when considering direct results of the CPP.
- **Integration of large amounts of renewables are expected to occur regardless of the CPP.** Results of the CPP Phase II analysis indicate that renewable resources, primarily wind and solar, will significantly increase between now and 2030 in both the Reference Case and CPP Base Case. Wind and solar capacity increases by approximately 110 GW between 2016 and 2030 in the Reference Case; this amount increases to 120 GW in the CPP cases. Wind capacity represents about 65 percent of this amount. This renewable capacity represents installed (or nameplate) capacity, which is discounted about 80 percent for wind and 35 percent for solar in terms of its on-peak capacity contribution. While intermittency of renewable resources poses potential challenges, NERC recognizes that the development of storage and other commercial technologies can serve to mitigate some of these effects.
- **Natural gas prices adjust the usage between coal and natural gas.** In the Reference Case, coal use increases by up to 300 TWh per year between 2016 and 2030, and natural gas use decreases by up to 550 TWh per year. The CPP causes lower coal-fired unit output as compared to the Reference Case and decreases the energy from coal-fired generation by up to 375 TWh per year through 2030. Natural gas use also increases by up to 87 TWh per year compared to the Reference Case.
- **The CPP is expected to flatten annual energy demand growth.** Compounded annual growth rates for electric demand have been declining over the last several years. The CPP provides direct and indirect incentives for increases in demand-side activities that reduce load, which accelerates this decline. Additionally, conservation and distributed resource growth are expected to contribute to declining growth rates. While the Reference Case shows a 0.61 percent average compounded annual growth rate in electric demand, the CPP Base Case indicates a 0.31 percent average compounded annual growth rate.
- **Trading of allowances under a national trading program could result in more coal use and less natural gas use.** Depending on the natural gas prices and the availability and liquidity of allowance trading markets or arrangements, coal use could increase given the availability of underused coal resources. Increased emissions from coal would be offset by renewables and natural-gas-fired generation. Coal use increases by up to 104 TWh/year in the National Trading Case versus the CPP Base Case by 2030 and natural gas use decreases by up to 78 TWh per year during the same time period. The trading of allowances provides significant additional flexibility for state compliance strategies.
- **Potential acceleration of nuclear retirements would shift the resource mix and increase renewables and natural-gas-fired generation.** Up to 18 GW of additional renewables and up to 21 GW of additional natural gas generation would be required by 2030 to fill the void from an accelerated level of nuclear retirements versus the CPP Base Case. 31 GW of nuclear capacity were found to be at risk in this case.
- **Resource mix changes as a result of both the reference and CPP cases have regional significance, spurring the need for additional transmission and pipeline infrastructure.** Most new wind resources are built in MISO and SPP, and most new natural gas generation is built in PJM and SERC. By 2030, 46 percent of SPP energy generation (up from 16 percent in 2015) is expected to come from renewable sources in the CPP Base Case and 22 percent (up from 8 percent today) of MISO's generation is expected to come from renewable sources. PJM and SERC see a 25 percent and 29 percent reduction in coal generation

respectively by 2030 and a 38 percent and 18 percent increase in Combined Cycle Gas Turbine (CCGT) generation. The risks from delays in generation, transmission, and upstream natural gas pipeline infrastructure construction need to be managed to ensure continued reliability of the BPS.

Recommendations

- NERC's assessment underscores the significant changes that are occurring on the BPS. Many of these changes are occurring regardless of whether the CPP is implemented. Because new transmission, natural gas pipeline infrastructure, and generating resources will be needed to support these changes over the next 14 years, the planning processes should already be underway to ensure that this infrastructure can be built in a timely manner.
- Planning coordinators and transmission planners should conduct system reliability evaluations to identify areas of concern and work in partnership with states and policy makers to provide clear guidance for the necessary planning activities that must transpire to assure BPS reliability. System evaluations could use the NERC CPP Phase II study as a basis for more granular and localized assessments. These system evaluations must identify system risks as well as develop mitigation plans to address them.
- The CPP final rule stipulates that state submittals must demonstrate that reliability has been evaluated and addressed. States must work with ISOs/RTOs to ensure that this is accomplished through the planning process. NERC advises planners to review and incorporate recommendations from Reliability Considerations for Clean Power Plan Development 1into their state plans. Particularly, state plans should take the following into consideration to ensure reliability:
  - Utility commissions and state environmental offices should ensure that sufficient levels of essential reliability services (ERSs) are planned and included in resource plans as large levels of asynchronous generation are incorporated into the BPS.
  - Utility commissions and state environmental offices must account for timing considerations of the necessary upstream infrastructure in the development of new resources.
  - State plan submittals must retain adequate reserve margin levels.
  - Planners must consider the changing operating characteristics of resources and incorporate those affects from these changes into their resource planning processes.
  - State and utility planners must also account for changes to, and the feasibility of, regional imports and exports as a result of interregional changes in power flows to meet their obligations as a result of the CPP. There is additional compliance risk for states that rely on resources that require transmission to be approved by neighboring states.
  - State Planners must assess the amount of required emissions reductions that can be met through trading of emissions allowances or emission reduction credits.
- The EPA, the Department of Energy (DOE), and the Federal Energy Regulatory Commission (FERC) entered into a Memorandum of Understanding whereby they agreed that, working together, the three agencies will make reasonable efforts to: (1) monitor the progress of states as they develop single-state or multistate plans to meet the requirements of the CPP; (2) monitor the implementation of state plans or, where applicable, a federal plan, to maintain awareness of any potential electric reliability effects; and (3) ensure coordination, as appropriate, to address any issues concerning reliability that may arise.2 The memorandum further stipulates that the agencies will engage with stakeholders, including utility trade associations, organizations of state agencies, ISOs/RTOs, NERC, and additional entities that participate in

[1] http://www.nerc.com/pa/RAPA/ra/Reliability percent20Assessments%20DL/Reliability%20Considerations%20for%20State%20CPP%20Plan%20Development%20Baseline%20Final.pdf
[2] https://www.ferc.gov/media/headlines/2015/CPP-EPA-DOE-FERC.pdf

reliability planning and execution. These agencies should continue to work together in conjunction with the aforementioned stakeholders to ensure that, as state plans are being developed, reliability has been ensured throughout the process and that final state plan submittals have addressed and resolved any reliability issues as a result of CPP compliance.

- NERC should continue its work around sufficiency guidelines for ERSs as well as its formulation of a task force to evaluate distributed energy resources on the distribution system that may have an effect on BPS reliability. These activities should be aligned with FERC's efforts around primary frequency response as delineated in FERC's recent Notice of Inquiry in Docket No. R16-6-0003; FERC's NOPR on Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities in RM16-8-000; and FERC's NOPR on Reactive Power Requirements for Non-Synchronous Generation in Docket No. RM16-1-0004.

[3] https://www.ferc.gov/whats-new/comm-meet/2016/021816/E-2.pdf
[4] https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-3.pdf

Chapter 1: Introduction and Background

The intent of this assessment is to inform regulators, state officials, public utility commissioners, utilities, and stakeholders of potential resource adequacy and reliability risks that emerge as a result of implementing the EPA's CPP final rule. Additionally, the assessment identifies considerations that would mitigate the impact of these risks toward assuring the continued reliability of the BPS. This Phase II assessment can help stakeholders: (1) make informed decisions about the reliability ramifications of the final rule; and (2) prepare imminent state and regional plans—as well as the requisite infrastructure—necessary to ensure the reliability of the BPS. NERC will continue to coordinate with states and regional groups as they develop their plans to provide insights on considerations that need to be accounted for to assure continued BPS reliability. NERC will continue to evaluate BPS reliability through its annual Long Term Reliability Assessments.

On June 2, 2014 the *EPA issued its proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, commonly referred to as the proposed CPP. The CPP was issued under section 111(d) of the Clean Air Act which introduces CO_2 emission limits for existing electric generation facilities. The proposed rule aimed to cut CO_2 emissions from existing power plants to 30 percent below 2005 levels by 2030. As part of the proposed rule, initial reductions would have been mandated beginning in 2020 and continue in subsequent years until the full amount of emission reductions were achieved by 2030.

NERC conducted a special assessment around the proposed rule and released a report in April, 2015 titled *Potential Reliability Impacts of EPA's Proposed Clean Power Plan Phase I.* NERC made the following general recommendations in its report:

- NERC should continue to expand and update the assessments of the reliability implications of the proposed CPP.
- Coordinated regional and multiregional industry planning and analysis groups should continue to conduct detailed system evaluations to identify areas of reliability concern and work in partnership with states, regions, and policy makers to provide clear guidance of the complex interdependencies resulting from the CPP rule's implementation.
- Policy makers, states, regions, and regulators (including the EPA) should develop implementation plans that allow for more time to address potential BPS reliability risks and infrastructure deployment requirements during the transition period.
- The EPA should include a formal reliability assurance mechanism in the final rule that provides the regulatory certainty and explicit recognition of the need to ensure reliability during both the plan development and the implementation period through 2030– and potentially beyond.
- State and regional plans should be developed in consultation with reliability authorities—planning coordinators and transmission planners—to review plans and demonstrate their reliability through established planning analyses and processes.

Following the release of the proposed CPP preliminary rule, the EPA evaluated over 4.3 million public comments and conducted outreach across industry to evaluate options to restructure the preliminary rule into a final rule that would still meet the EPA's overall goals for carbon emission reductions from electric generating units. On August 3, 2015, the EPA issued its final rule, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units.*[5] Some of the major modifications to the final rule versus the preliminary rule are the following:

[5] https://www.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants

- Initial compliance of the final rule begins in 2022 versus the 2020 date that was established in the preliminary rule.
- Each state plan must address reliability in its submittal demonstrating that reliability has been maintained. Furthermore, the final rule provides for a reliability "safety valve" that can be invoked in the event of a catastrophic condition that could affect reliability.
- The final rule aims to cut CO_2 emissions from existing power plants to 32 percent below 2005 levels by 2030.
- The final rule, as the preliminary rule does, outlines a best system of emissions reduction (BSER) by using building blocks to provide options to reduce emissions. The BSER in the final rule identifies the following building blocks:
  - Improving coal unit heat rates
  - Greater use of natural-gas-fired capacity
  - Increasing use of renewable resources

The final rule eliminated a fourth building block that would have expanded energy efficiency measures.

In November 2014, NERC began its multiphase approach to reliability assessment around the CPP. NERC's special assessments around the CPP include NERC's Initial Reliability Review[6] around the proposed CPP; and NERC's Phase I special assessment of the proposed CPP[7]. After the final rule was issued on August 3, 2015, NERC developed Reliability Considerations for CPP development,[8] which was directed toward states and state environmental offices, underscoring reliability considerations that states must take into account as state plans are being developed. As depicted in Figure 1-1, this is NERC's Phase II assessment, which is intended to provide a reliability assessment around resource adequacy as a result of implementing EPA's final rule, as well as to provide a framework for additional studies to be conducted by Regions, ISOs/RTOs, utilities, and planning coordinators around the CPP final rule.

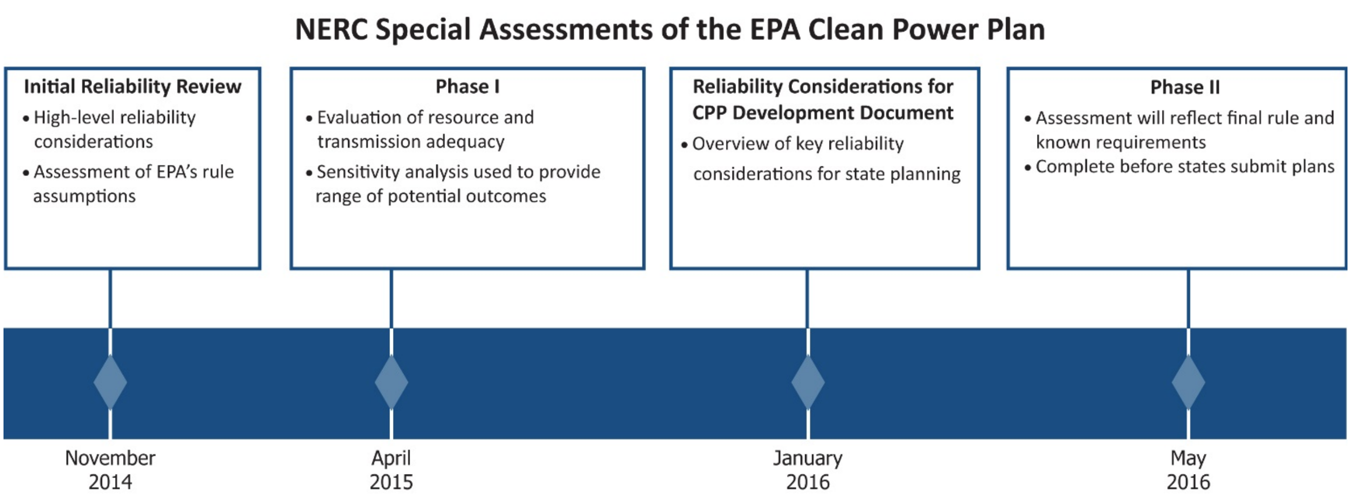


Figure 1-1: NERC's Multiphase Approach to Reliability Assessment around EPA's CPP

[6] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf
[7] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential%20Reliability%20Impacts%20of%20EPA%E2%80%99s%20Proposed%20Clean%20Power%20Plan%20-%20Phase%20I.pdf
[8] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Reliability%20Considerations%20for%20State%20CPP%20Plan%20Development%20Baseline%20Final.pdf

The key objectives of Phase II are to:

- Determine how achieving the CO_2 reduction goals, as established by the CPP, will impact the U.S. generation mix and resource adequacy, based on a set of model input assumptions.
- Conduct sensitivity analysis to examine the range of potential outcomes across different cases.
- Identify potential risk that must be addressed and mitigated to assure BPS reliability during the transition.

About this Reliability Assessment

Assessment Approach

NERC focused on providing insight and guidance about potential reliability aspects from implementing the CPP final rule and specifically did not assess alternative CO_2 reduction methods. NERC's role is to evaluate the composite framework of potential outcomes to help guide the planning and implementation process to ensure the continued reliability of the BPS.

For its resource adequacy analysis, NERC used two generator dispatch models: AURORAxmp and IPM. In this assessment, NERC is evaluating general trends and overarching themes—high precision within the model outputs was not a key objective as this effort is not a comprehensive planning study. NERC compares the results of the two models determining if the identified themes and trends are consistent between them.

NERC retained two consultants to employ their resource planning models to develop a Reference Case and case results. Both used NERC's common input assumptions. The findings and conclusions are based on the independent analysis of the results by NERC's Reliability Assessment staff.

NERC performs its long-term, seasonal, and special reliability assessments using publicly available forecasts, assumptions, cases, engineering judgment, and practicality based on historical performance. Stakeholder and technical input is sought through a variety of forums, including the Planning Committee's CPP Advisory Group, the Reliability Assessment Subcommittee, and the Member Representatives Committee.

NERC's Phase II special assessment employed two models to identify a range of potential outcomes under various different cases. The special assessment examined the following cases for each model:

- **Reference Case**: a business-as-usual forecast without implementation of the CPP.
- **CPP Base Case**: a sensitivity case around CPP implementation with intrastate trading of emission allowances and trading within the existing Regional Greenhouse Gas Initiative (RGGI) paradigm.
- **High Renewable Penetration Case**: a sensitivity case that assigns lower costs to technological development and operational and maintenance costs (O&M) associated with renewable technologies
- **Accelerated Nuclear Retirements Case**: a sensitivity case that applies an accelerated rate to nuclear retirements.
- **National Trading Case**: a sensitivity case that assumes trading of emission allowances will be optimized across all states.

NERC leveraged key information from these sensitivities to identify potential cumulative impacts on a region-wide or interconnection-wide basis. Throughout this special assessment a stakeholder advisory group—formed by the NERC Planning Committee—provided advice, input, and vetting of the underlying assumptions and publicly available data.

Figure 1-2 shows the CPP Phase II cases.

Figure 1-2: CPP Phase II Cases

Models Run

NERC employed two models (IPM and AURORAxmp) in its analysis in order to compare trends and results. Each of the CPP Phase II cases were run using both models. The first model run was the IPM model. IPM was the model that the EPA used in its CPP analysis.

IPM

IPM is a production cost simulation model designed to project competitive market prices of electrical energy.

The model also projects plant generation levels, new power plant construction, fuel consumption, and interregional transmission flows using a linear programming optimization routine with dynamic effects (i.e., IPM looks to future years and simultaneously evaluates decisions over an entire forecast horizon).

All major factors affecting wholesale electricity prices are accounted for in IPM. The model includes a detailed representation of existing and planned units, with careful consideration given to fuel prices, environmental allowance and compliance costs, and operating constraints.

IPM projects hourly spot prices of electric energy and the annual capacity price. IPM estimates the marginal cost of emission reductions for the electric generating sector.

IPM determines the lowest cost means of meeting the environmental regulatory requirements, such as CO2 emissions caps, and forecasts allowance prices for each cap and trade market and compliance costs, unit dispatch, and retrofit decisions for each boiler and generator.

For the analysis, model run years of 2016, 2018, 2020, 2022, 2025, and 2030 were used. In general, interpolated years assume a constant growth rate between run years.
Figure 1-3 provides an overview of the IPM Analytic Framework.

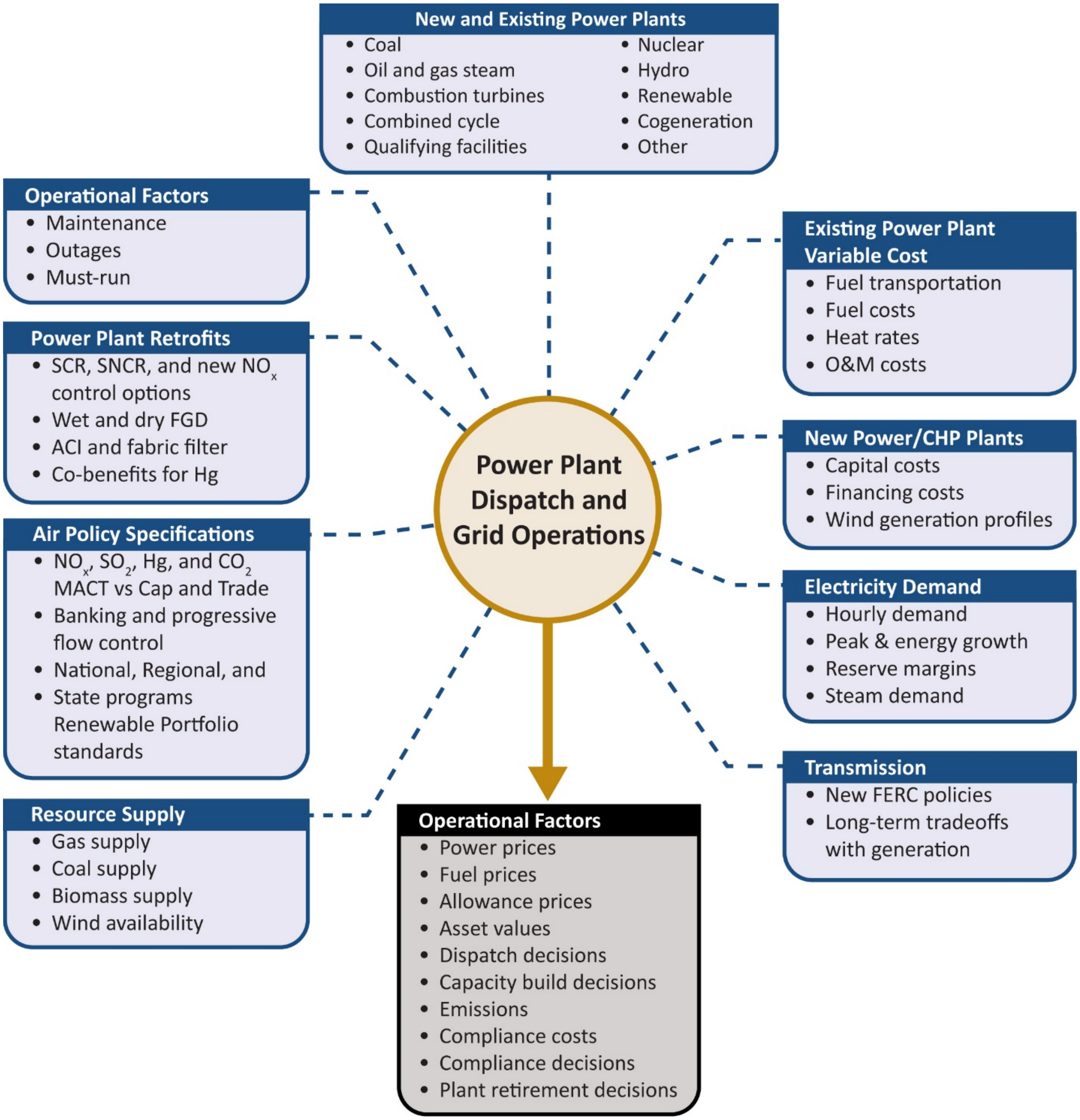


Figure 1-3: IPM Analytic Framework

AURORAxmp

The AURORAxmp electric power market forecasting tool is a fundamentals-based power market model that economically dispatches generation capacity to simulate the operations of each power market in the continental United States. The model optimizes dispatch by using the lowest cost resources to meet electricity demand in a given region at the hourly level, and builds the most economic new resources to meet reserve margin targets and future load growth.

The AURORAxmp dispatch logic economically dispatches each generation unit against electricity demand for each chronological hour.

Figure 1-4 provides an overview of the AURORAxmp analytic framework incorporating the elements of the CPP input assumptions:

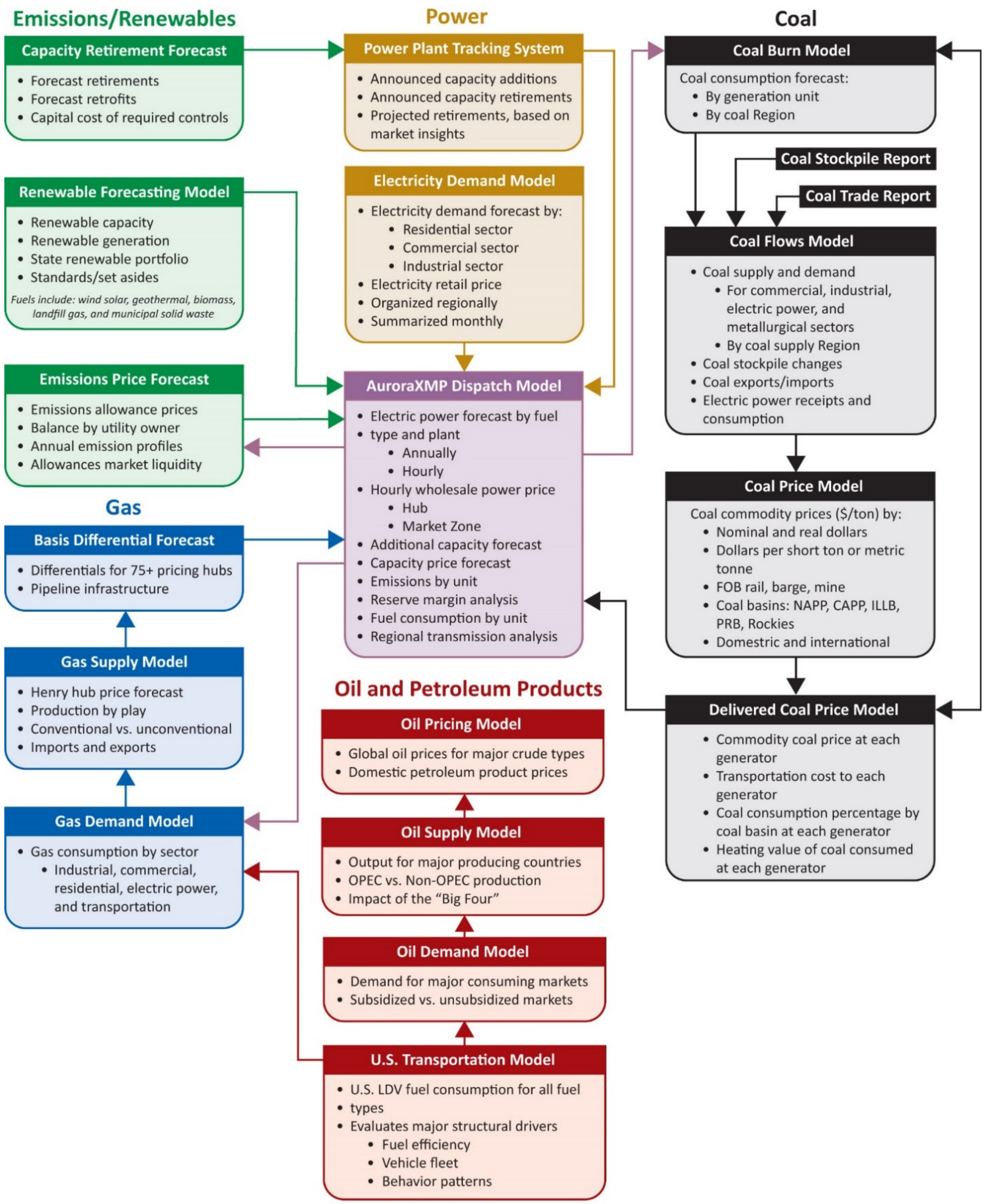


Figure 1-4: AURORAxmp Modelling Structure

The input assumptions for each model (AURORAxmp and IPM) have slightly differing effects although both models indicated similar slopes in both capacity and energy shifts of all resource types between 2016 and 2030. Whereas IPM retires more coal in the early years of the analysis and builds more renewables as compared to AURORAxmp the trends of both models result in similar resource implications throughout.

Qualification

Uncertainty exists in regards to whether the rule will remain unchanged or overcome potential legal challenges. Additionally, the ultimate timing of submittal of preliminary and final state compliance plans cannot be accurately forecasted. Various outcomes may result depending on whether states choose a mass-based or rate-based plan, as well as each state's decisions regarding individual state plans versus submittal of multistate trading ready plans. NERC recognizes that changes to any one of these parameters will have an effect on the analysis and results presented here.

Notably, the approach to formulate internally consistent assumptions, which are then formed into key cases, is designed to provide benchmarks and guidance about potential reliability implications during the implementation of the CPP rule. The models' results illustrate only potential cases and purely mathematical outcomes at a specific point in time, based on input assumptions also applicable to a specific point in time. Models cannot truly forecast the business decisions of the multiple government and utilities business entities when faced with a fully adjudicated final rule. Therefore, the results are representative of a range of potential outcomes used to assess potential reliability impacts, but may not be indicative of what will necessarily happen. Other modeling based on different decisions would produce different results; however, this analysis is useful to explore the range of outcomes. The cases selected are intended to achieve this goal.

NERC's modeling is designed to mathematically solve for the lowest cost options for meeting generation and capacity needs subject to the CPP. The process assumes that utility business decisions will follow the economics that the businesses are faced with. The results rely on the premise that decisions to build new utility-scale generation will be made to replace existing generation and meet electricity demand in the future as a result of economics. NERC's modeling is a conservative approach that does not rely on new technologies that are not yet widely integrated into the BPS or major changes in consumer choices and behaviors; however, NERC recognizes that significant additional conservation and distributed generation would have an impact on the results. Additionally, the models might be significantly different if the analysis of least-cost additions included the transmission costs and losses associated with different types of resource additions. More detailed planning that includes transmission and pipeline costs, as well as the associated timing, may lead to different resource additions.

Chapter 2: Phase II Study Assumptions

This study examines the potential grid reliability impacts created by the implementation of the EPA CPP final rule. However, several major policy, technology, and market uncertainties remain that can have potential major impacts on reliability. First, this rule is under litigation and the ultimate outcome of the legal challenges is uncertain. Emission limitations and program compliance schedules could change. Second, the final rule provided a framework that gave states flexibility in how they develop their final program limitations and state implementation plans. Different alternative state policy options could create incentives that could influence compliance plans and result in a range of grid reliability impacts. Finally, changes in future electricity demand growth, generation technology advancements, and fuel markets could directly influence compliance costs and plans. Some policy uncertainties can be addressed in setting different cases to quantify their potential impact on power markets and grid reliability. However, there is a practical limit to the number of cases. This limit leaves this study to make assumptions for several important factors. The important assumptions and their potential impacts are briefly discussed below:

- **State Limitation Approach**: The EPA final rule provided states several different alternatives to comply with the CPP, as shown below in Figure 2-1. Significant differences exist in state compliance strategies between rate-based and mass-based limitation alternatives. Based upon the ease of administration of a mass-based compliance strategy, as well as indications from state environmental program officials that a majority of states will choose a mass-based program, the mass-based limitation approach was assumed in this analysis. In some cases (RGGI, California) a mass-based cap and trade program structure is already in place.

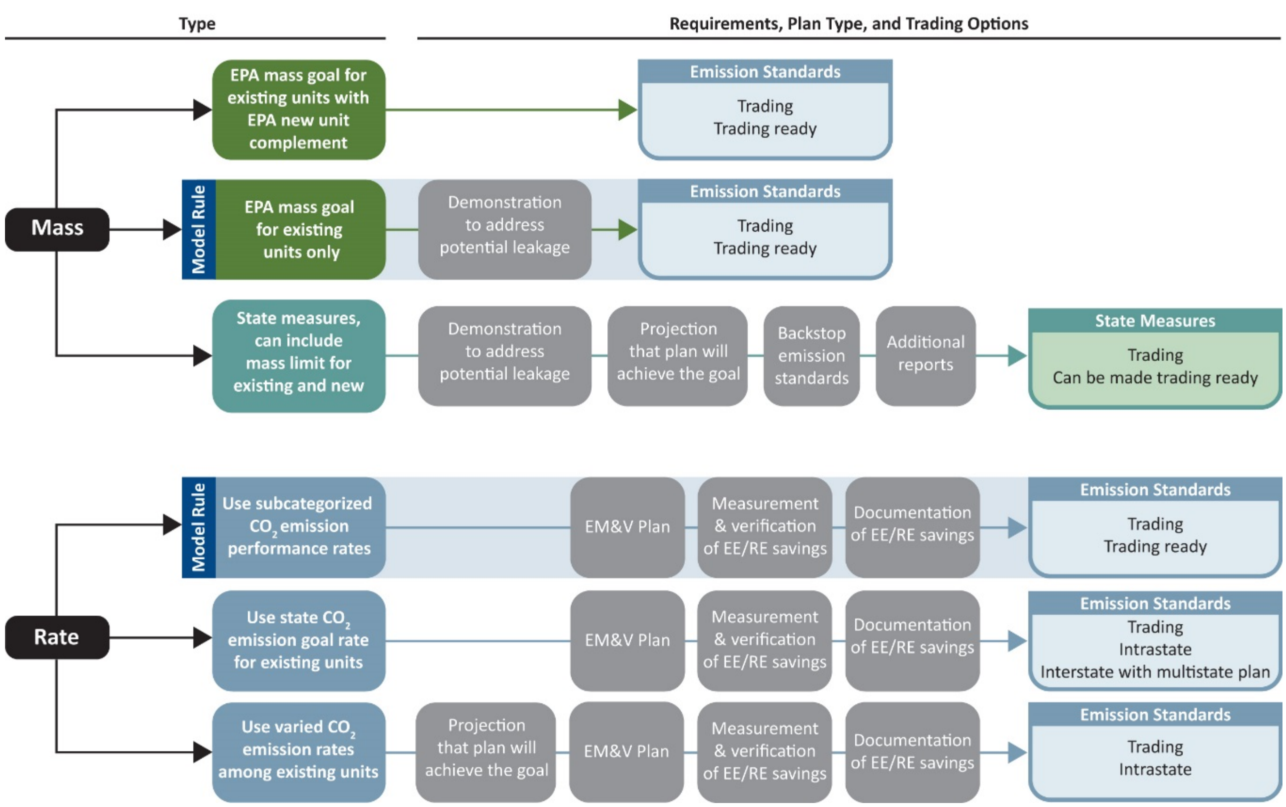


Figure 2-1: Alternative EPA Approved Policy Options

However, a few states with new nuclear power projects (i.e., GA, SC, TN) or a large renewable generation market share potential may find the rate approach to be more advantageous. For this study, the more preferred mass-based limitation cases are evaluated.

In addition, this study assumes that states will be able to develop, plan and implement mass-based limitations and unit allocations by the 2022 compliance date. Additionally NERC's analysis assumes that all states will comply and therefore none will be subjected to the Federal Implementation Plan, the default mechanism established by EPA for states that fail to submit an acceptable plan to the EPA.

- **Covered Units**: States have the flexibility to regulate only existing affected sources (meeting EPA's affected unit criteria) with an approved plan to address "leakage,"[9] or a larger state budget to cover all (new and existing) fossil-fired sources, alternatively. This study adopts a model rule approach that regulates only the 3,056 listed affected fossil fuel generators. This study addresses leakage by adopting EPA's draft plan approach. This approach is to set aside 5 percent of the annual state emission budget and then to award these allowances to qualifying renewable projects. The allowances are assumed to be sold at market value and the generated funds used to support additional in-state renewable projects to reduce leakage.
- **Allowance Trading**: The EPA final rule provides states the flexibility to form and participate in multistate allowance trading programs. Given the wide range in marginal compliance costs between individual states, interstate trading has the potential to shift compliance investments to lower marginal cost states and to avoid reduction measures in higher marginal cost states. Allowance trading can have significant grid reliability impacts. Generally, the more constrained trading is, the higher the risk for greater system disruption and grid reliability impacts. For this study, the CPP Base Cases assumed "constrained trading," or restricting to just intrastate allowance trading, with one exception—the Regional Greenhouse Gas Initiative states. To quantify the reliability impacts of allowance trading, a national interstate trading case has also been examined.
- **Strategic Allowances**: Under existing EPA emission cap and trade programs, generators have developed a strategic bank of allowances. These allowances are kept to assure continued system reliability, compliance, and operational flexibility during unanticipated system outages or changes in system loads. To stimulate this expected future behavior, all power generators are assumed to develop by 2024 and maintain a strategic allowance bank equivalent to 10 percent of their 2030 allocation.
- **Coal Heat Rate Improvement**: The EPA rule provides incentives for power suppliers to invest capital to improve their coal unit heat rate efficiency and lower their CO2 emission rate. The amount of this potential improvement is directly a function of the coal quality, boiler condition and design, unit operational loading, and environmental controls (cooling water, ash handling, pollution controls, etc.) and should vary significantly by individual coal unit. For the purposes of this modeling, an estimated heat rate efficiency improvement and capital cost for each coal unit was developed, based upon historical operational data of similar units, unit loading curves, and capital cost of the range of potential upgrade measures. These algorithms were reviewed with major utility systems to assure that they reflected the current potential and cost. However, the CPP will also result in changing unit dispatch that will reduce coal use. This will adversely affect the annual unit efficiency and offset a portion of the heat rate improvement. Overall, the combination of the lower U.S. coal use in combination with the heat rate investment will result in the U.S. coal fleet improving its overall annual efficiency by 1.1 percent.
- **New Generation Capital and Performance Costs:** New generation capital investment costs and performance play an important role in unit retirement vs. replacement capacity decisions as well as in the selection of the generation technology for needed new builds. As generation technology continues to

[9] Leakage refers to cases in which electric generation growth is met with expanded output (and emissions) from nonregulated sources (e.g., new sources).

advance, these capital investment costs are likely to decline (in real dollars) and performance can improve. The pace and extent of these technology improvements can differ among industry experts. The reference generation capital cost and performance assumptions used in this analysis are provided in Appendix. In all cases, regional factors for each technology, as developed by the DOE 2010 study, were applied to the reference capital cost assumption to account for differences in labor costs, productivity, and material/supplies. This analysis adopted the National Renewable Energy Laboratory (NREL) renewable generation capital and performance projections included in Appendix Given the large potential role of renewables in compliance and their effect on grid reliability, an alternative High Renewable Penetration Case with even faster technology advancements and performance improvement is also evaluated.

- **Reference Reserve Margins:** In order to support and maintain grid reliability, balancing areas have adopted reserve margin requirements. These reserve margin requirements are set to trigger building new generation capacity in time to reliably meet electricity demand growth and handle unanticipated forced unit outages, while also accounting for the variable nature of intermittent resources. This study incorporates each of the participating power pool reserve margin requirements. Both the AURORAxmp and IPM models assume that the all new capacity can be planned, permitted, financed, and brought online in the time needed to comply with their reserve margin obligations. The models also use existing transmission to evaluate power flows (they do not build transmission). Therefore, generation builds must ultimately have the requisite transmission incorporated into overall system planning. The greater the new annual generating capacity needs, the greater the potential reserve capacity risk becomes. In addition, variable generation resources (e.g., wind) are often not available to meet system peak demand requirements and earn only partial credit towards meeting the system margin needs. The wind capacity eligible for reserve margin credit varies by power pool and how the power pool credit rules are applied. The wind and solar capacity credits with existing nameplate capacity are provided in Figure 2-2 and Table 2-1.

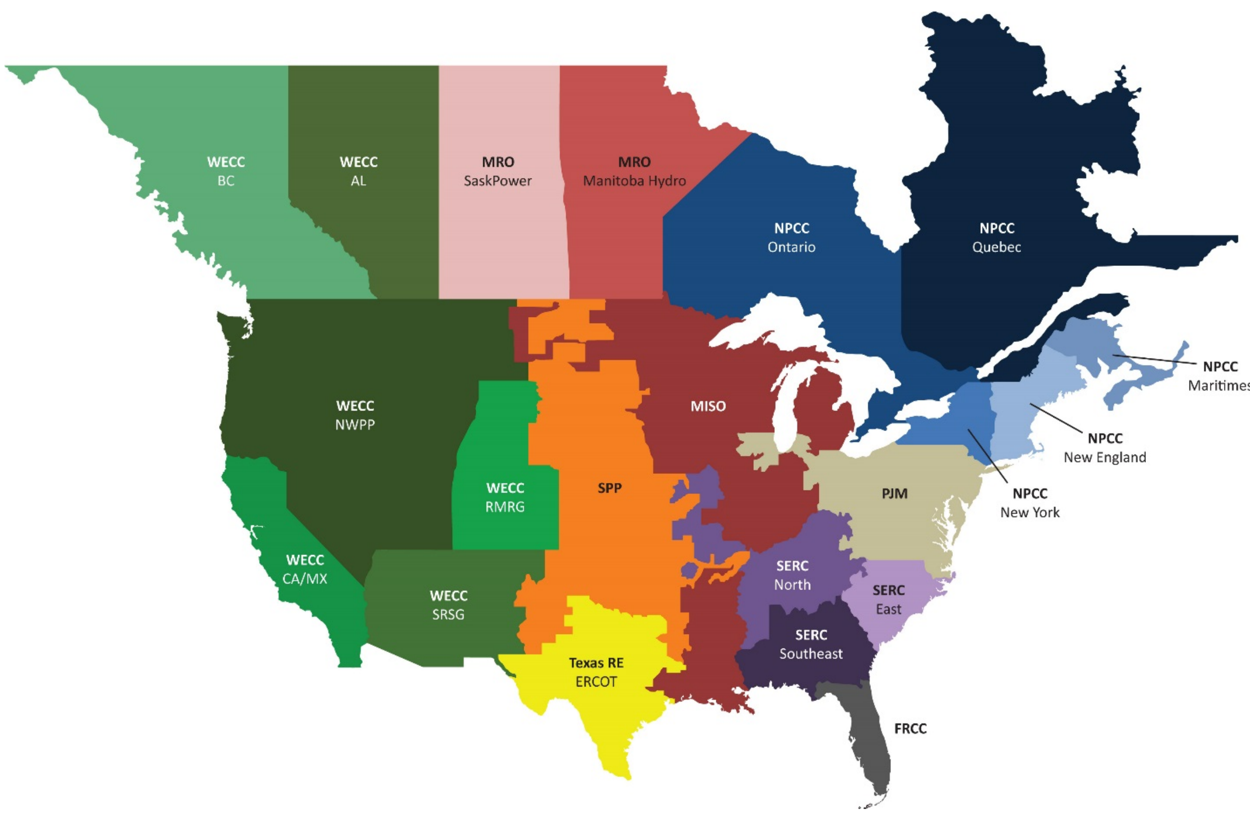


Figure 2-2: Assessment Areas

Table 2-1: 2016 Peak Season Anticipated Capacity for Variable Generation

	Wind			Solar		
Assessment Area / Interconnection	**Nameplate Wind**	**Expected Wind**	**Expected Share of Nameplate (%)**	**Nameplate Solar**	**Expected Solar**	**Expected Share of Nameplate (%)**
FRCC	-	-	0.00%	83	30	36.39%
MISO	15,102	1,773	11.74%	-	-	0.00%
MRO-Manitoba Hydro	259	-	0.00%	-	-	0.00%
MRO-SaskPower	221	22	10.00%	-	-	0.00%
NPCC-Maritimes	1,112	146	13.17%	-	-	0.00%
NPCC-New England	784	92	11.70%	373	149	39.95%
NPCC-New York	1,446	231	15.94%	32	16	49.52%
NPCC-Ontario	3,983	502	12.60%	280	96	34.41%
NPCC-Québec	3,260	-	0.00%	-	-	0.00%
PJM	6,194	955	15.42%	402	120	29.85%
SERC-E	-	-	0.00%	30	30	100.00%
SERC-N	177	26	14.41%	-	-	0.00%
SERC-SE	-	-	0.00%	176	176	100.00%
SPP	12,980	1,843	14.20%	190	124	65.50%
TRE-ERCOT	16,654	2,879	17.29%	295	236	80.00%
WECC-CAMX	8,750	657	7.51%	9,581	2,053	21.43%
WECC-NWPP-CA	1,952	557	28.54%	2	0	0.02%
WECC-NWPP-US	9,921	2,011	20.27%	867	234	26.99%
WECC-RMRG	2,927	498	17.01%	201	60	29.85%
WECC-SRSG	835	142	17.01%	1,231	145	11.78%
EASTERN INTERCONNECTION	42,257	5,589	13.23%	1,565	741	47.36%
QUÉBEC INTERCONNECTION	3,260	-	0.00%	-	-	0.00%
TEXAS INTERCONNECTION	16,654	2,879	17.29%	295	236	80.00%
WECC INTERCONNECTION	24,385	3,865	15.85%	11,882	2,492	20.97%
TOTAL-NERC	**86,556**	**12,333**	**14.25%**	**13,742**	**3,469**	**25.25%**

- **Energy Efficiency:** The EPA CPP will provide additional incentives for additional investment in energy efficiency measures. These measures can displace incremental fossil fuel alternatives and lower system emissions. With the incorporation of new carbon penalties (from the CPP) in combination with the displacement of low cost coal alternatives, wholesale power prices are likely to rise and make energy efficient investments increasingly more favorable. Currently, the industry spends more than $2 billion/year in energy efficiency measures and these investments will likely continue independent of carbon emission regulation.

  Under the reference no carbon case, the amount of additional incremental energy efficiency potential would equal the achievable economic potential for each region as projected in Electric Power Research Institute's (EPRI) April 2014 report, *US Energy Efficiency Potential Through 2025*. In this comprehensive study, the achievable potential (AP) represents a forecast of likely consumer adoption that takes into account existing market delivery, financial, political, and regulatory barriers that are likely to limit the amount of savings that might be achieved through energy-efficiency programs. For example, utilities do not have unlimited budgets for program implementation. There can be regional differences in attitudes toward energy efficiency and its value as a resource. AP is calculated by applying a program implementation factor (PIF) to the AP for each measure. The PIFs were developed by taking into account recent utility experience with such programs and their reported savings. These factors also change over time to reflect that programs may be able to achieve increased savings as programs mature.

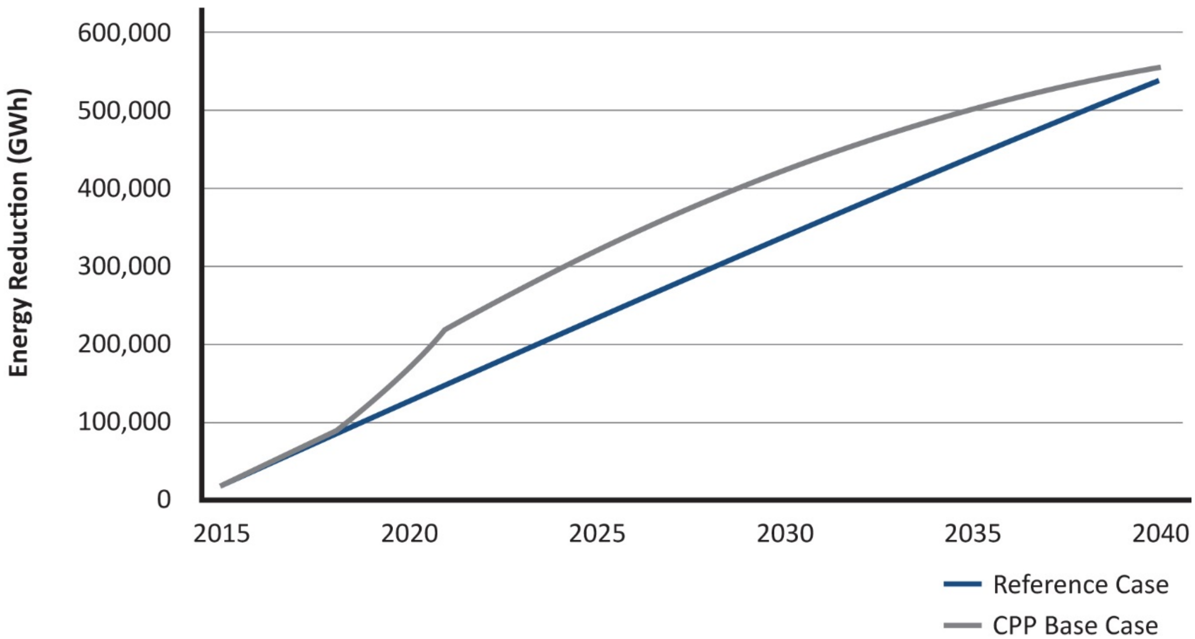


Figure 2-3: Assumed Energy Efficiency Savings Assumptions Derived from 2014 EPRI Study

For the CPP Case, power suppliers would increase investments, starting in 2019, and reach energy efficiency's high achievable potential (HAP) as defined by the same EPRI report by 2022. HAP is estimated by applying market acceptance ratios (MARs) to the economic potential savings from each measure in each year. MARs capture the effects of market barriers, which include transactional, informational, behavioral, and financial barriers at a high level. They are essentially scaling factors applied to the measure savings over time, and are defined in ten-year intervals and change over time (maximum of 100 percent) to reflect that market barriers are likely to decrease over time. MARs can also be thought of as representing what exemplary energy efficiency programs have achieved, assuming that they have overcome market barriers to some extent.

As shown in Figure 2-3, these alternate energy efficiency assumptions will eventually converge as the HAP potential markets reach saturation levels and its growth rate slows.

- **Peak Demand**: Peak demand plays an important role in grid reliability. As the peak demand grows, new capacity must be built to maintain regional reserve margin requirements. Control areas have options to reduce demand growth such as peak shaving and/or demand reduction programs to shift power needs from peak to off-peak periods. The competiveness of these peak shaving programs versus building new generation supplies are evaluated in this study. However, other important peak demand drivers (e.g., weather, economic growth) are clearly outside the grid control area inputs and not part of the model development of the low cost resource mix. For this study, the regional electric load duration curves for each load area have been set to reflect average weather conditions and long term observed consumptions patterns. Given the high cost of load shifting programs, the peak demand growth rate is generally equal to the regional electricity growth rate. As a result, the model's new capacity build requirements do not reflect adverse weather events.

- **Announced and Planned Fossil Unit Capacity Retirements and Additions**: For this study, the model incorporates all announced fossil unit retirements and new capacity builds that have been financed, contracted and/or under construction. A complete listing of these units is provided in the Appendix.
- **Fuel Prices**: The fuel prices used in this analysis are derived from fuel supply and transportation models. These models calculate the fuel price for each fossil generating unit in each case, based upon applying aggregated demand for each regional coal quality, natural gas commodity, and the fuel supply curve. As regional fuel demand changes under the various runs, the annual regional fuel prices are recalculated until an equilibrium price is reached. Fuel transportation costs incorporate forecasts of different regional gas basis differentials and unit-specific coal delivery costs based upon delivery logistics, carrier competition and haul distances. These two components are added together to derive unit-specific delivered fuel prices. Natural gas prices were developed using both New York Mercantile Exchange (NYMEX) and annual energy outlook (AEO) Energy Information Administration (EIA) 2015 natural gas forward curves. Since spot and forward natural gas prices have dropped since the AEO EIA 2015 natural gas curve was first published, the study uses a hybrid approach for natural gas prices using NYMEX prices in 2016 and 2017 and bridges those prices with AEO EIA 2015 prices in the years 2018 and 2019.

  Natural gas prices are forecasted to rise according to EIA projections. As natural gas prices rise, more coal generation will be utilized, contrary to its recent large decline. This holds true in both the Reference Case and the CPP Cases. However, in the CPP-modeled Case, the projected increase in coal utilization is significantly lower than in the Reference Case, indicating that the CPP will clearly reduce overall coal utilization. If natural gas prices were to remain at historically low levels, coal usage would not increase and more natural-gas-fired generation would most likely be built. Increases in gas utilization could potentially pose timing challenges in regards to ensuring the requisite natural gas pipeline infrastructure is built and the natural-gas-fired generation and associated transmission is in place. In the Phase II analysis, natural gas prices are assumed to start at levels consistent with recent NYMEX futures and grow over time consistent with EIA's AEO 2015 Reference Case. In the Reference Case, Henry Hub gas prices increase from approximately $2.40/MMBtu in 2016 to approximately $5.60/MMBtu in 2030 in 2015 dollars as shown in Figure 2-4. Gas prices from the CPP Case display a similar trend. Average coal prices in the US remain low. In the Reference Case FOB coal prices increase from approximately $1.00/MMBtu in 2016 to approximately $1.20/MMBtu in 2030 as shown in Figure 2-5.[10]

[10] A further description of the fuel commodity price assumptions are detailed in the Appendix.

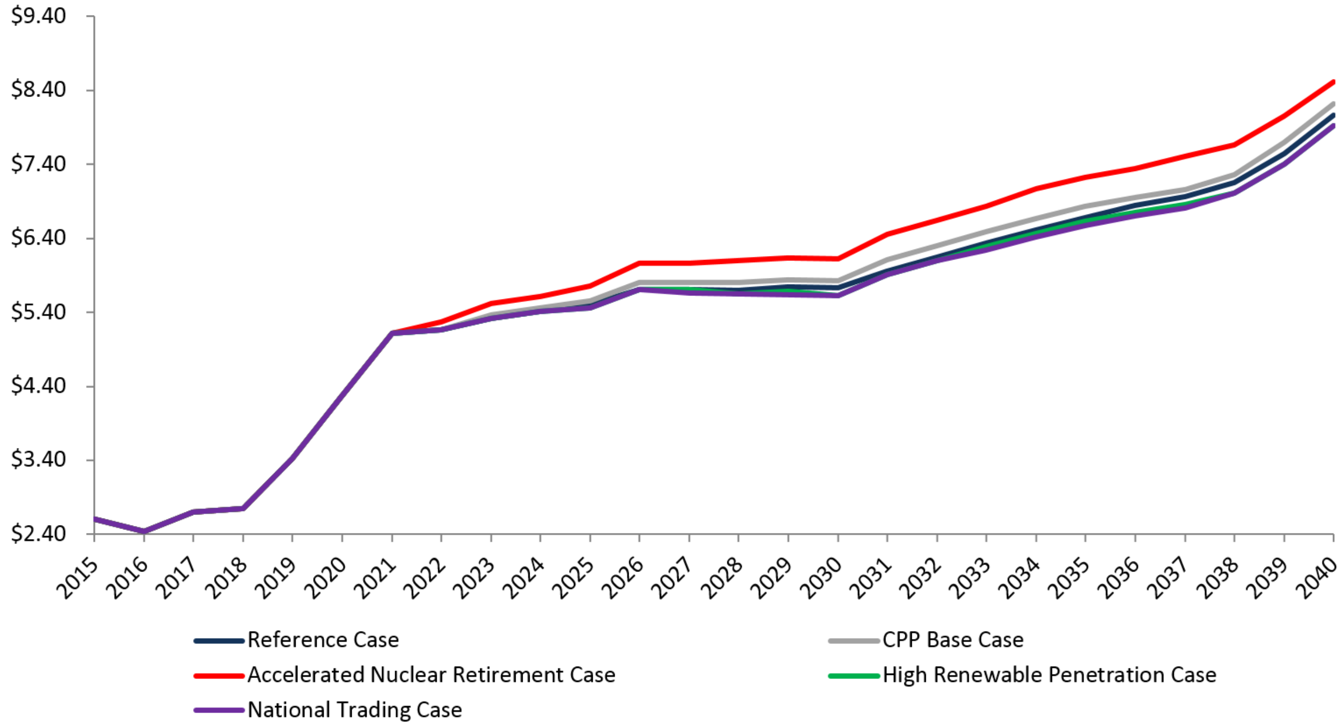


Figure 2-4: Weighted Average Natural Gas Price, AURORAxmp

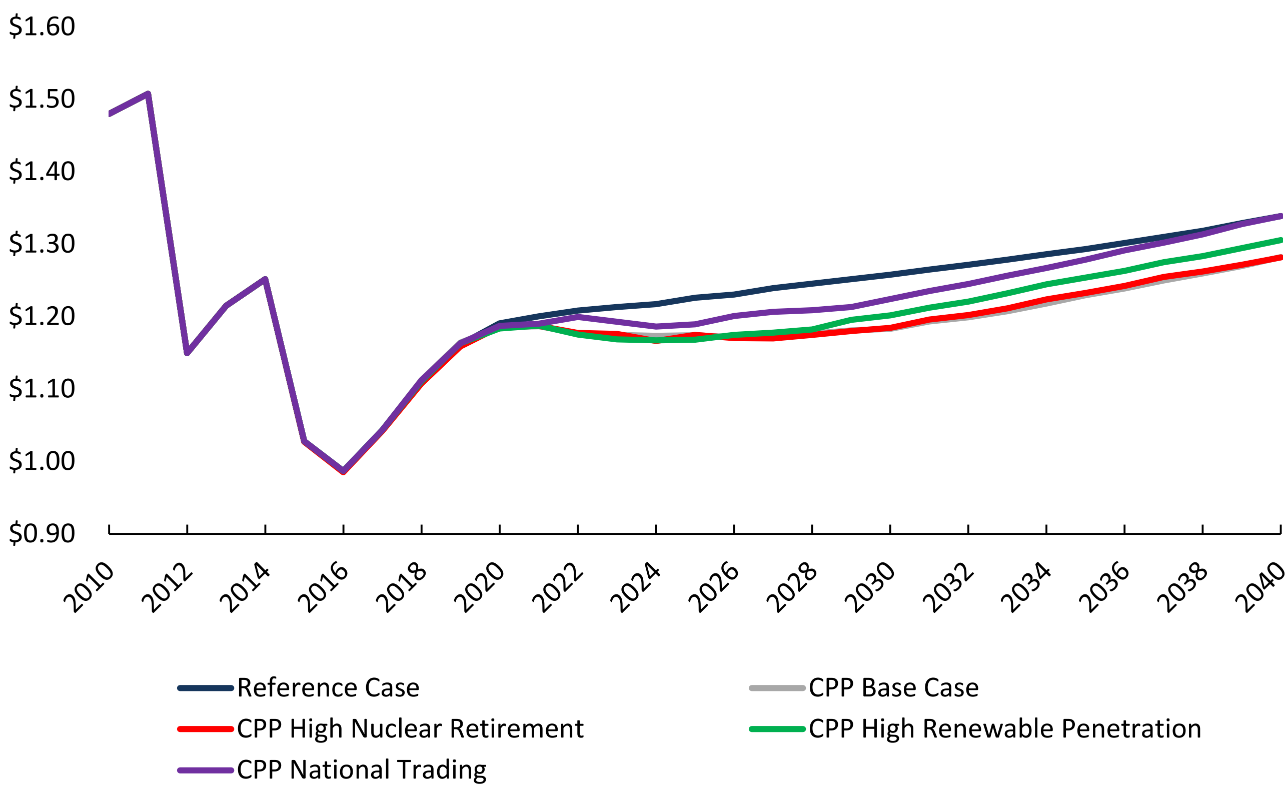


Figure 2-5: Weighted Average FOB Coal Price, AURORAxmp

Chapter 3: Reference Case – No Clean Power Plan

The purpose of the Reference Case is to set a baseline to understand how the final CPP directly impacts the resource mix and the resulting reliability needs. The Reference Case, as with all of the cases, models the years 2016–2030. The Reference Case represents business-as-usual, which assumes no CPP.

Resource Mix: Capacity (GW)

Both IPM and AURORAxmp indicate a decline in coal and an increase in natural-gas-fired capacity between 2016 and 2030. Whereas the IPM model retires more coal in the early years of the analysis as compared to the AURORAxmp model, both models show a decline in coal capacity and an increase in natural gas capacity.

Coal

The IPM model shows coal declining from 270 GW in 2016 down to 224 GW by 2022 and 222 GW by 2030. The AURORAxmp model shows a similar downward decline in coal; however, the rate of retirement is more gradual and about 12 GW of coal is not retired when compared to the IPM model. Much of the decline is due to already announced retirements from existing Clean Air Act requirements (e.g., Mercury and Air Toxics Standards, regional haze, coal combustion residuals). Natural gas prices increasing from today's levels would cause a smaller coal decline over time. The 2016 Henry Hub natural gas price is at \$2.40/MMBtu whereas the 2030 price is at \$5.60/MMBtu in 2015 dollars, as assumed from the modeling inputs. Figure 3-1 shows the decline in coal in the Reference Case for both the IPM and AURORAxmp models.

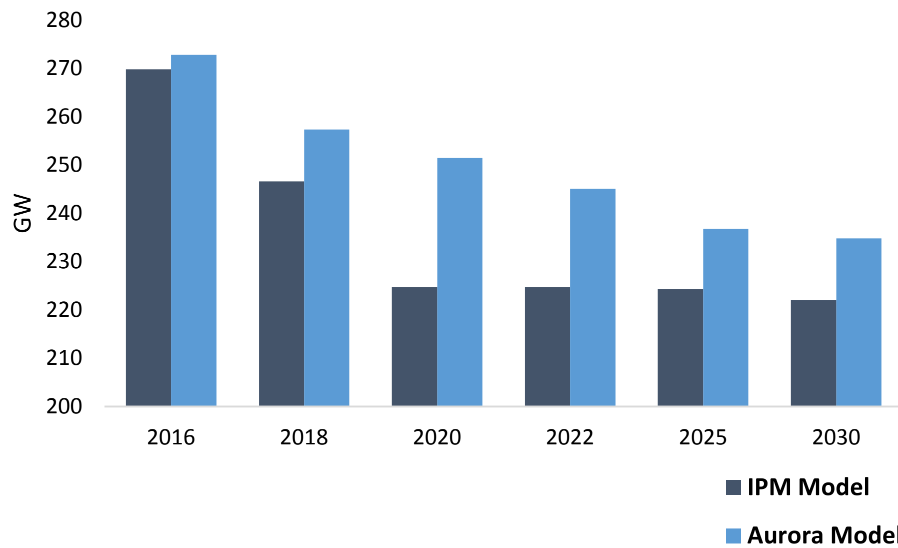


Figure 3-1: Coal Capacity - Reference Case

Natural Gas

The decline in coal-fired capacity contributes largely to an increase in natural-gas-fired capacity. Both models demonstrate this increase in natural-gas-fired capacity as shown in Figure 3-2. Whereas the AURORAxmp model shows natural gas combined-cycle capacity increasing from 232 GW presently to 275 GW by 2018 the IPM model shows an increase from 233 GW to 253 GW during the same time period. A smaller increase in natural gas prices or a decline over time would have much larger implications for the overall level of natural-gas-fired capacity. These projects are already in the development pipeline and will largely replace the announced coal unit retirements.

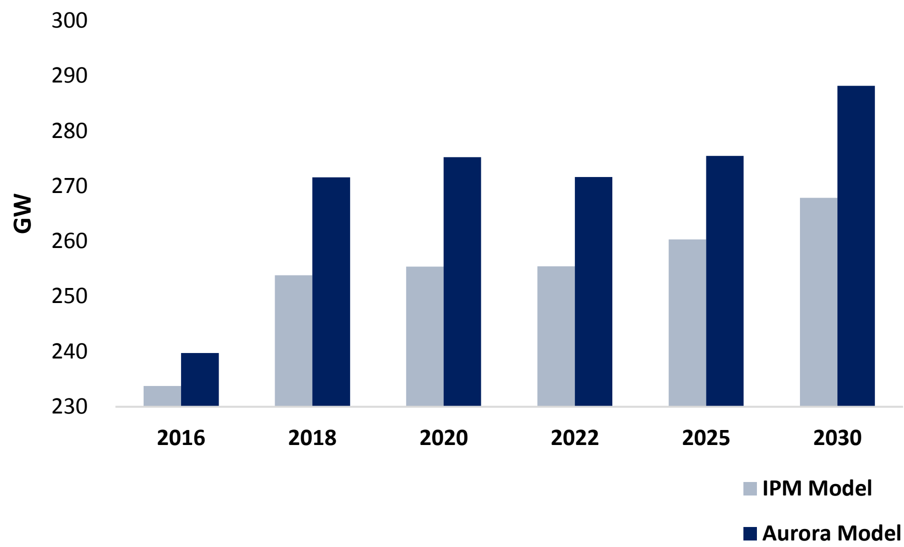


Figure 3-2: Natural Gas Capacity -Reference Case

Nuclear

Both AURORAxmp and IPM models assume that the five nuclear units under development (Vogle #3-4, Summer #3-4, and Watts Bar #2) are built and brought on-line in the Reference Case. No additional nuclear units are built during the modeling period for this Reference Case.

Renewables

Both models show a large increase in renewables in the Reference Case between 2016 and 2030. The AURORAxmp model Reference Case shows significant builds of both wind and solar above present levels (74 GW additional wind and 12 GW utility-scale solar). The near-term escalation is driven by the combination of the state renewable portfolio standard (RPS) incentives and the recent extension of the production tax credit (PTC) and the investment tax credit (ITC). Longer-term outlooks are linked to the continuation of RPSs and the outlook for continued technology improvements that drive down costs and improve output performance to allow them to become increasingly competitive. Biomass and geothermal play only a limited role in this expansion because of their higher production costs and resource limitations.

In the IPM Reference Case, renewable generating capacity increases by greater than 100 GW between 2016 and 2030. This is the largest shift in absolute capacity numbers of all of the generation types. The increase in renewable capacity in both models is demonstrated in Figures 3-3 and 3-4. The renewable capacity indicated is nameplate capacity and therefore is not the full amount that can contribute to a peak requirement. For system planning purposes and reserve margin calculations, these values must be adjusted downward in order to properly account for the on-peak contribution. The recent extensions of both the renewable energy production tax credit and the renewable energy investment tax credit result in a significant increase in renewable generation in the Reference Case, as well as the additional modeling cases that will be shown later. For the PTC, it is modeled as reinstated retroactively to 2015 and remaining intact at $.023/kWh through 2016, before stepping down to 80 percent of the value in 2017, 60 percent in 2018, and 40 percent in 2019. It will zero out in 2020, but importantly, the support applies to projects which have merely begun construction by that time, not placed in service. Thus, the extension will effectively cover wind projects coming online through the end of 2021. The PTC value escalates by the Consumer Price Index.

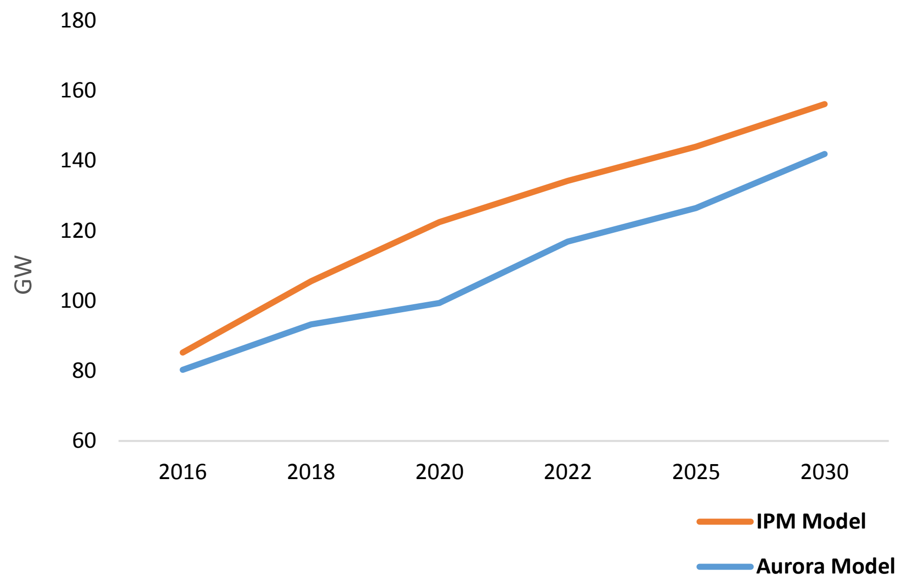


Figure 3-3: Reference Case for GW Wind Capacity

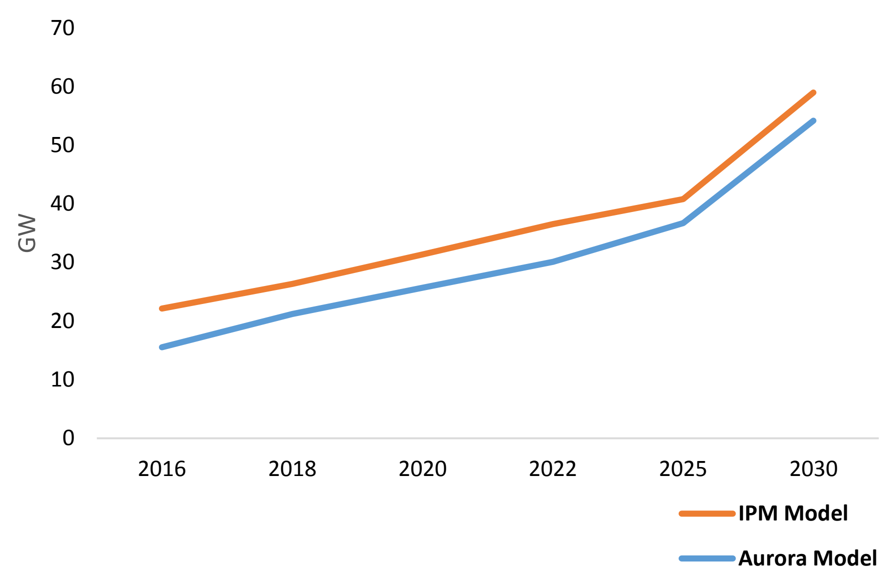


Figure 3-4: Reference Case for GW Solar Capacity

The ITC will be held at 30 percent through 2019 and is then gradually phased down to 10 percent by 2022, where it will remain for commercial projects, but will be subsequently be phased out for residential projects. As with the PTC, the level of support received is based on when a project commences construction, not when it is placed in service—provided the project is completed by the end of 2023.[11,12]

Summary

The models show that a near-term expansion of natural gas combined-cycle capacity will largely replace announced coal unit retirements with most of these projects already in the development pipeline. The renewable

[11] http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc
[12] http://energy.gov/savings/business-energy-investment-tax-credit-itc

outlook shows the growing market role of wind and utility-scale solar as state RPS requirements, continuing technology improvements and incentive programs offset their current higher cost. The renewable energy capacity additions are designated in name plate capacity and therefore the necessary derates should be applied for peak day planning. Total generating capacity between 2016 and 2030 increases from 1,054 GW to approximately 1,176 GW in the AURORAxmp model and from 1053 GW to approximately 1127 GW in the IPM model. Figure 3-5 shows the overall trends in the resource mix in both the IPM and AURORAXMP models.

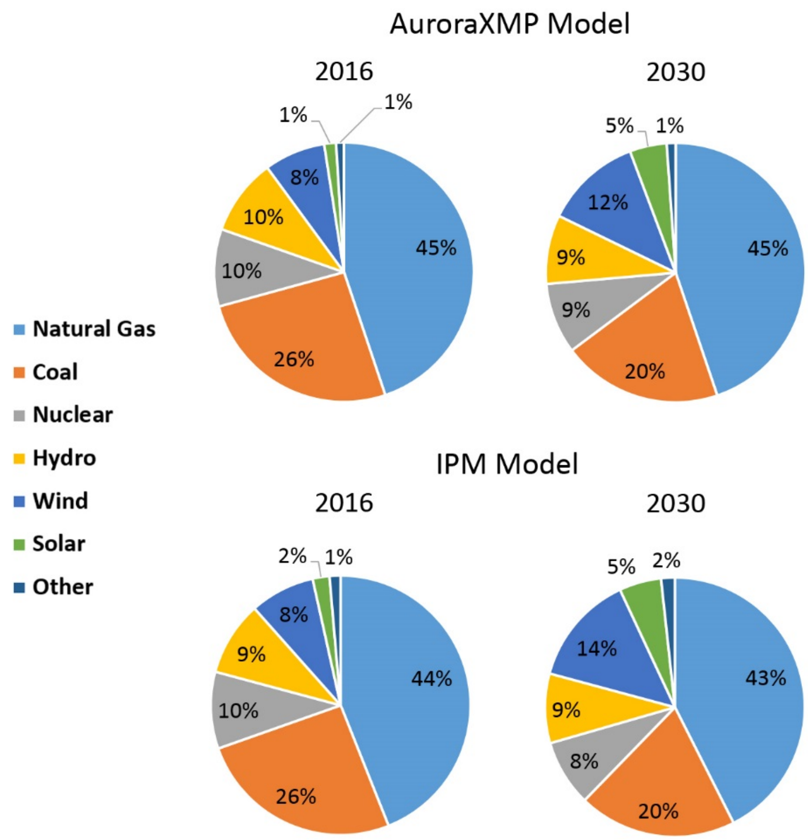


Figure 3-5: Percent Capacity Mix

Resource Mix: Generation (GWh)

Coal

While pending coal unit retirements should initially decrease coal generation by nearly 10 percent through 2018, the models show that increasing natural gas prices would cause a steady increase in coal generation. This would start in 2018 and continue until 2025 as the remaining coal unit fleet reaches average capacity factors greater than 75 percent in combination with a few additional coal unit retirements. The following Figure 3-6 shows the energy from coal-fired generation declining in the AuroraXMP model from 1,357 TWh in 2015 to 1,226 TWh in 2018 and then increasing to 1,625 TWh by 2024. Similarly the IPM model shows coal generation decreasing from 1016 TWh presently to 938 TWh in 2018 and then increasing to 1,524 TWh in 2025. Figure 3-7 demonstrates the increase in capacity factors of coal fired generation as a result of low coal prices and the remaining fleet being comprised of more efficient coal generating units.

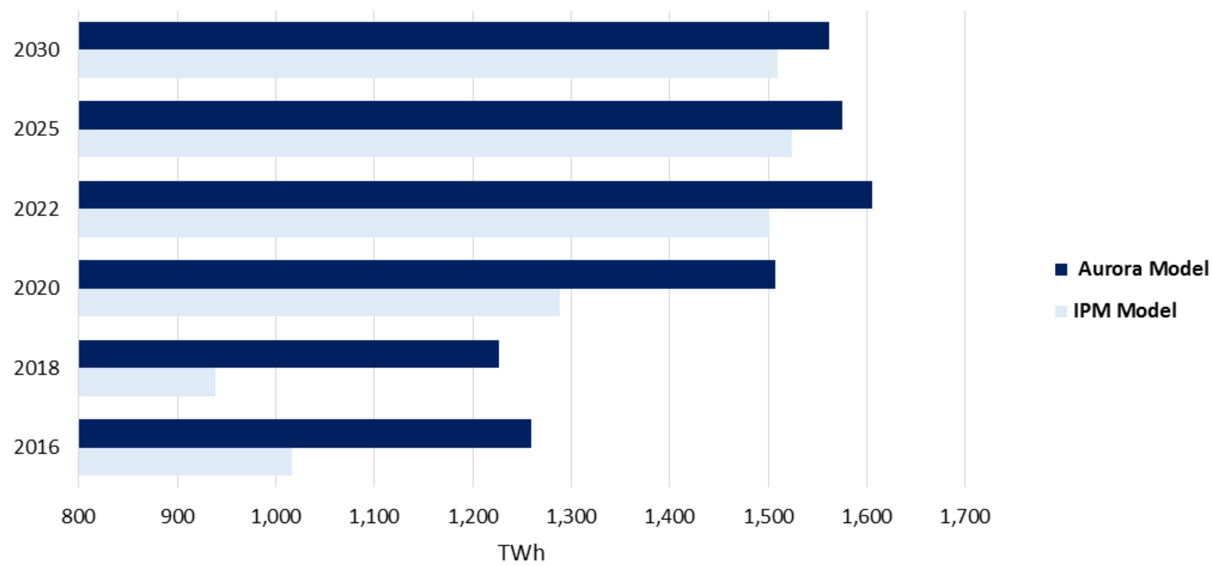


Figure 3-6: Coal Generation: Reference Case

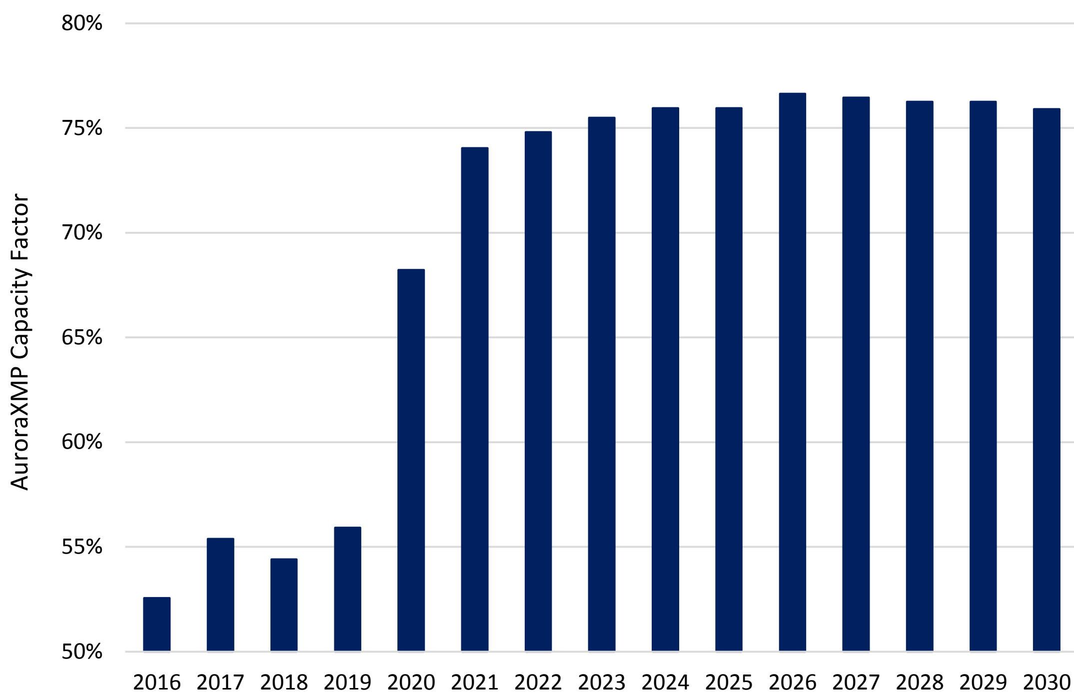


Figure 3-7: Coal Capacity Factor, AURORAxmp

Natural Gas

The trend is opposite for natural gas combined-cycle generation. With the retiring coal capacity largely being replaced by gas combined-cycle generation, natural gas generation increases in both models between 2015 and 2018 and then declines as gas prices rise. As this occurs, gas-fired generation returns to being on the margin and is subsequently partially displaced by cheaper coal generation through 2024. After 2024, the growth in power demand is met largely through gas combined-cycle and renewable generation. The following Figure 3-8 shows the energy from natural-gas-fired generation growing from 1,066 TWh presently to 1,168 TWh in 2018 in the

AURORAxmp model while subsequently declining to 796 TWh in 2024. Similarly, the IPM model shows combined-cycle generation increasing from 1,347 TWh in 2016 to 1,424 TWh in 2018 and then declining to 784 TWh in 2025.

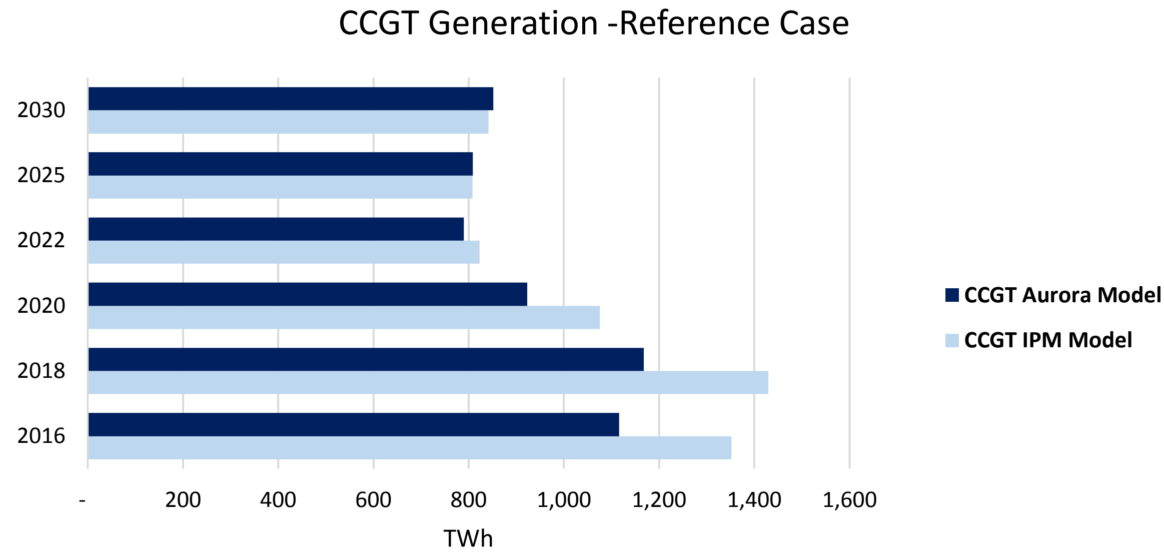


Figure 3-8: CCGT Generation: Reference Case

Nuclear

Nuclear generation remains relatively constant over the evaluation time period with the small increase attributable to limited planned new nuclear plant capacity coming online.

Renewables

Renewable power generation grows significantly over the forecast period, dominated by increases in wind and utility-scale solar. The renewable power expansion is driven largely by state RPS requirements, outlook for continued technology improvements and the recent extension of the renewable investment tax credit and production tax credit. Wind is expected to continue its rapid growth, more than doubling from 223 TWh in 2015 to reach 503 TWh in 2030 as shown in the AURORAxmp model; from 246 TWh in 2016 to 563 TWh in 2030 in the IPM model. Utility-scale solar generation also expands from 19 TWh in 2016 to 107 TWh by 2030 in the AURORAxmp model and from 31 TWh in 2016 to 102 TWh in 2030 in the IPM model. Utility-scale solar increases at rate much lower than wind. The growth in renewable power generation is shown in Figure 3-9**.**

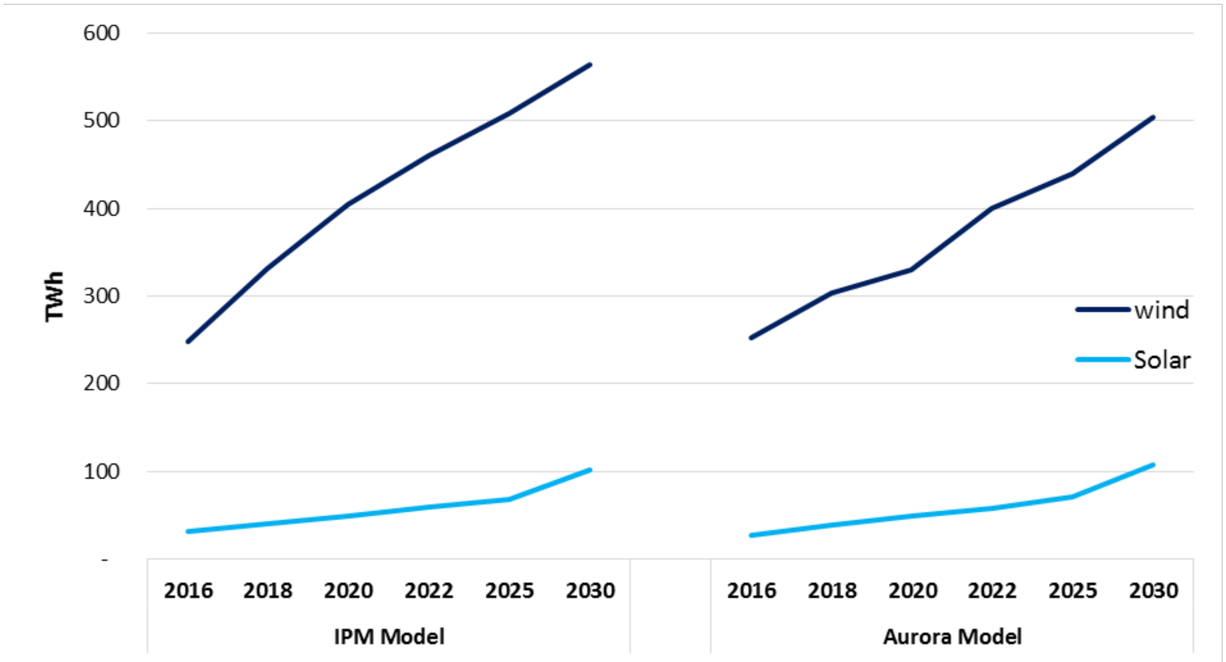


Figure 3-9: Renewable Power Generation

Summary

In the Reference Case, as outlined above, both the IPM model and AURORAxmp model show similar trends. Whereas coal units are retiring and natural gas units are being built, the largest capacity build-out will be from renewables. Wind and solar are expected to grow to comprise 17 percent of total generating capacity and 14 percent of the total energy (GWh) by 2030 (compared to 10 percent and 7 percent respectively in 2015).

The models show that a near-term expansion of natural gas combined-cycle capacity will largely replace announced coal unit retirements with most of these projects already in the development pipeline. The renewable outlook shows the growing market role of wind and utility-scale solar as state RPS requirements, continuing technology improvements, and incentive programs offset their current higher cost. The renewable energy capacity additions are designated in name plate capacity and therefore the necessary de-rates should be applied for peak day planning. Total generating capacity between 2018 and 2030 increases from 1,040 GW to approximately 1,129 GW. Natural gas demonstrates a decline from 30 percent to 28 percent of the overall generation mix in the AURORAxmp model between 2016 and 2030 and from 38 percent to 22 percent in the IPM model. Coal experiences an increase from 32 percent to 37 percent in the AURORAxmp model between 2016 and 2030 while the IPM model shows an increase from 25 percent up to 35 percent by 2030. Figure 3-10 shows the overall trends in the resource mix in both the IPM and AURORAxmp models.

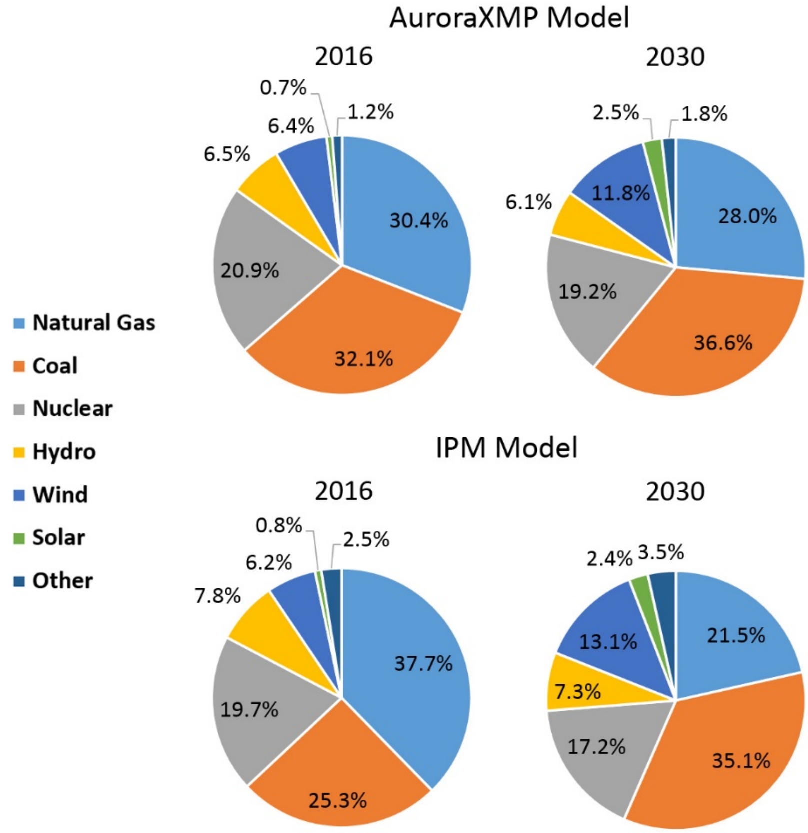


Figure 3-10: Percent Capacity Mix

Reliability Implications

In the Reference Case, as outlined above, both the IPM model and AURORAxmp model show similar trends. Whereas coal units are retiring and natural gas units are being built, the largest capacity build-out will be from renewables. Wind and solar are expected to grow to comprise 17 percentof total generating capacity and 14 percent of the total energy (GWh) by 2030 (compared to 10 percent and 7 percent respectively in 2015). To support this renewable market expansion even without the CPP, the industry will need to ensure adequate amounts of ERSs, such as frequency response, voltage support, and ramping capability is maintained for BPS reliability.

Years of effort may be required when building new generating resources or transmission lines that are necessary to support reliability or compliance with the CPP. The lead times required and associated uncertainties for the planning, engineering, permitting, and construction of new generating resources, transmission facilities, and fuel infrastructure may challenge the reliability of the BPS based on when such activities are commenced and the complexity of the solution. An analysis of industry planning and lead time experience is provided in the NERC CPP Phase I report.[13]

Uncertainty in the timing of such resource decisions and the ability to construct the necessary energy infrastructure to implement those decisions stem from the following factors:

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13 http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential%20Reliability%20Impacts%20of%20EPA%E2%80%99s%20Proposed%20Clean%20Power%20Plan%20-%20Phase%20I.pdf

- The addition of new generating resources can take several years to permit and construct. There will be a range of time periods depending on the circumstances related to each project and the availability of construction crews and equipment.
- Changes to resources (such as retirements or new generation) can require a need for additional electric transmission infrastructure. Such transmission can require many years to permit and construct, typically longer than generation construction, and timing will depend on the facts and circumstances of each project.
- Where new or repowered generating resources are dependent on natural gas as a fuel, there will be a requirement for additional gas pipeline infrastructure. Depending on the location of the plant relative to interstate gas pipelines, plant-specific gas infrastructure will require several years to permit and construct.
- The resource decisions of neighboring states can also impact the transmission infrastructure required to maintain reliability within a given state. In summary, generation resource decisions, including retirements, are not likely to be known by the time state plans are finalized. Furthermore, such resource decisions may require additional transmission and fuel infrastructure in order to be integrated reliably. The addition of new generation, fuel infrastructure, and transmission can all have significant lead times that could potentially impact successful implementation of a state plan.

Gas-fired generation can take up to five years to complete the requisite planning, permitting and construction. Transmission lines can take up to 15 years to complete. Natural gas pipeline infrastructure can take approximately three years to complete.[14]

Given these time constraints, it is important that system planners have sufficient time to plan, permit, and build this capacity to replace retiring coal units. For the Reference Case, most replacement capacity is already in process. However, these timing challenges may grow significantly with the additional changes driven by the CPP.

[14] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential%20Reliability%20Impacts%20of%20EPA%E2%80%99s%20Proposed%20Clean%20Power%20Plan%20-%20Phase%20I.pdf

Chapter 4: Base Case

The purpose of this case is to identify the direct impacts to the resource mix as a result of CPP implementation. As discussed in Chapter 2, the EPA final CPP provided states with several program alternatives in developing their state implementation plans. Based upon the ease of administration of a mass-based compliance strategy and the indication from state environmental program officials that a majority of states will choose a mass-based program, the mass-based limitation approach was adopted for this study.

As shown in Figure 4-1, the EPA state allocation formula required a wide range of different CO_2 emission reduction requirements for the states based upon their 2012 resources and demand requirements. This wide range in state reduction requirements will also result in a wide range of different compliance strategies and marginal compliance costs among the states. However, the EPA final rule gave states the flexibility to join multistate trading programs as one method to optimize compliance strategies and costs. Both the full interstate trading (national trading) and constrained trading cases (CPP Base Case) have been analyzed in this report; however, NERC has selected constrained trading[15] as its base CPP case since it offers the more conservative approach to emissions allowance trading.

To gain EPA approval for their mass-based limitations, the states are required to limit leakage from non-affected units. For this analysis, the EPA-proposed draft strategy of setting aside 5 percent of the state allocation for qualified renewable providers was adopted. These allocations would be awarded to in-state renewable providers and be sold in the open market. All revenues would be applied to offset the costs for new additional in-state renewable projects.

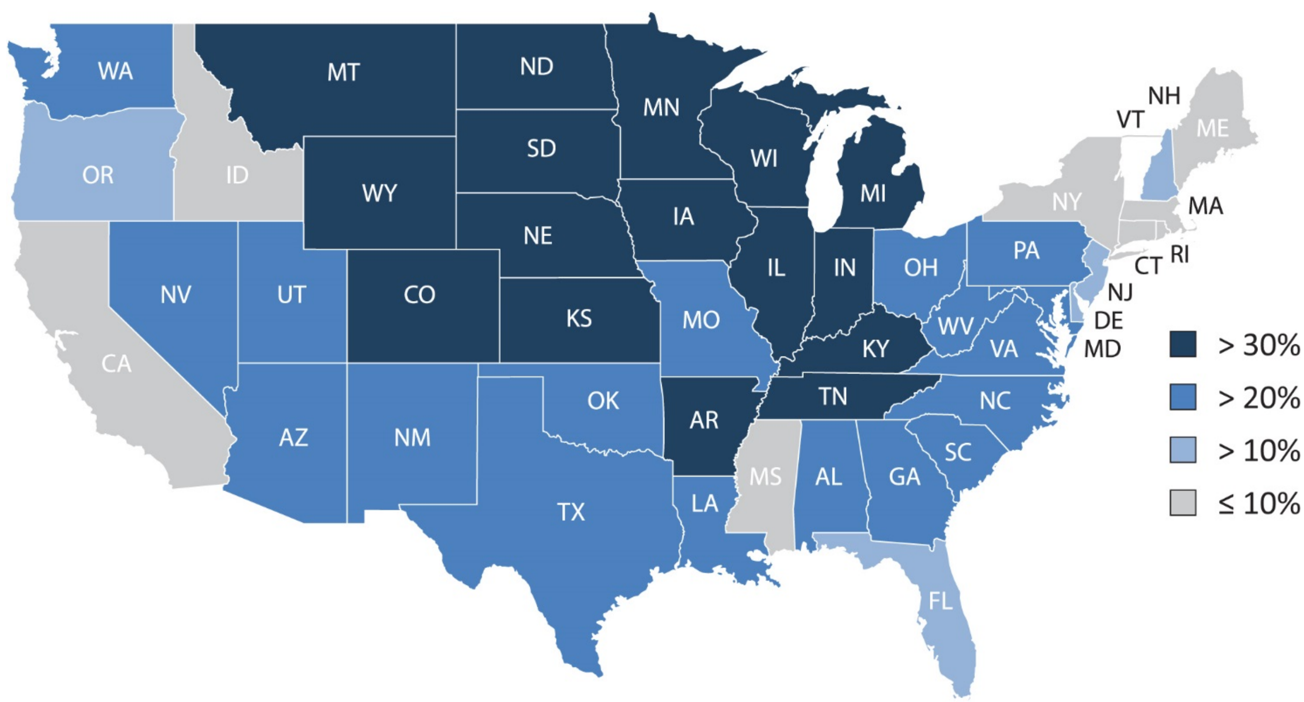

Figure 4-1: State CO_2 Emission Reduction Requirements

[15] Constrained trading assumes that the existing RGGI state cap & trade program is maintained allowing the 8 states to continue trading mass CO2 allowances under their existing agreements. However, all other states are assumed to allow only intra-state trading to simulate worst case outcome conditions.

Demand: Compounded annual growth rates for electric demand have been progressively declining over the last several years. This decline continues in the CPP Cases. The decline associated with the CPP Cases is a result of lower demand from increased costs of generation and increased energy efficiency as a result of the Clean Energy Incentive Program associated with the CPP.[16] At the national level, load is 4 percent lower in the cases with the CPP than the Reference Case by 2030. There are regional differences in the impacts of energy efficiency on load assumptions relative to the national average difference. For example, FRCC's load is 6 percent lower in the cases with the CPP by 2030, the largest difference from Reference Case levels among all NERC Regions. Load in MRO, RF, and SPP is 3 percent lower in the CPP Cases, the smallest among all NERC Regions. To the extent that demand for electricity rises unexpectedly due to an accelerating economy, this could create reliability issues that could in turn affect CPP compliance. Figure 4-2 shows the differential in load outlook by Region in the Reference Case versus the CPP Base Case.

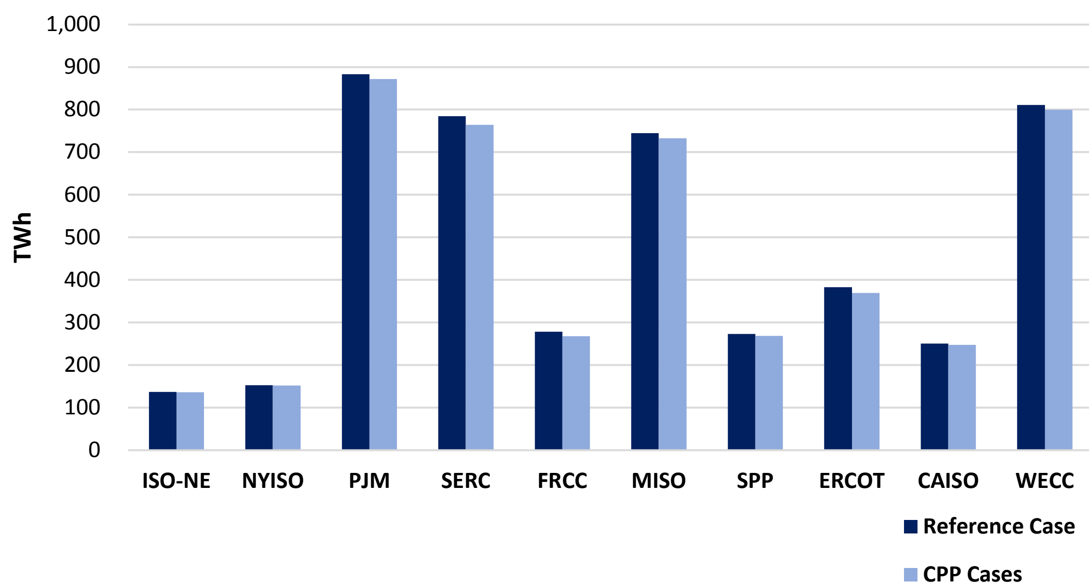

Figure 4-2: TWh Load Outlook 2030 – AURORAxmp Model

Transfers: The CPP is expected to change some future power flows due to differences between state carbon penalties. States can use additional import power to reduce in-state generation and lower emissions. As shown in Figure 4-3, power imports from Canada are expected to increase starting in 2022 due to the CPP as its new carbon penalty starts to be incorporated in the U.S. economic dispatching costs, U.S. power prices should rise faster than Canadian import prices. These imports should back out higher marginal cost alternatives in MISO. MISO, PJM and SERC are expected to see increases in their power imports as well as a large drop in retail sales (from enhanced energy efficiency programs) due to meet the carbon targets in the EPA CPP.

[16] https://www.epa.gov/cleanpowerplan/fact-sheet-clean-energy-incentive-program

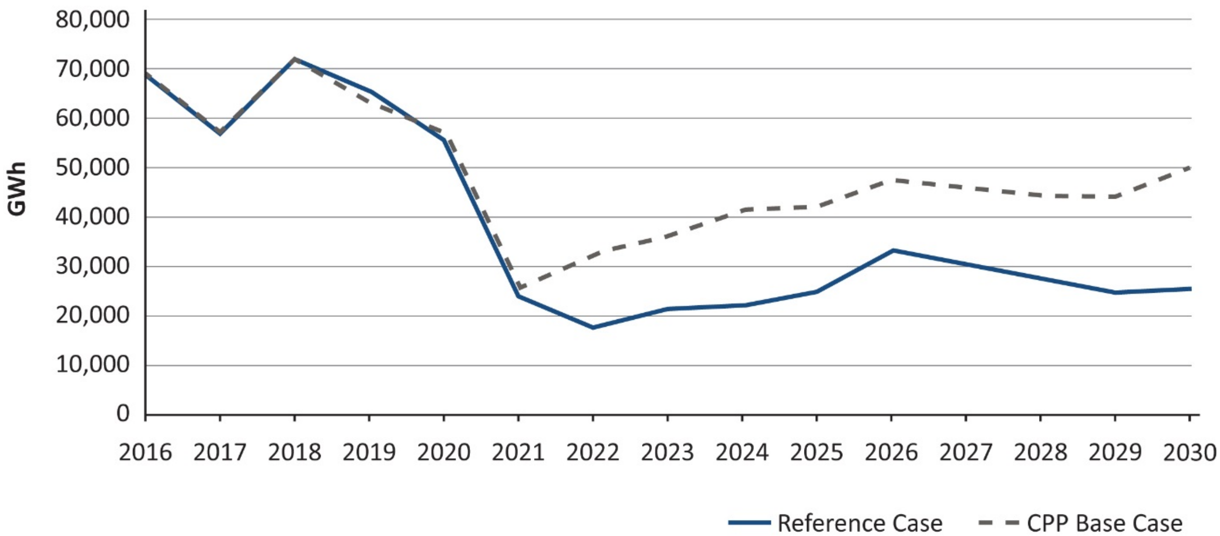

Figure 4-3: Power Imports from Canada – AURORAxmp Model

The major resource shifts as a result of the CPP are described in more detail below. These resource shifts are similar in both the IPM and AURORAxmp models.

Resource Mix – Capacity (GW)

Coal

To meet the mass limitations contained in the EPA CPP, large amounts of existing coal-fired generation must be displaced by a combination of enhanced energy efficiency measures, gas combined-cycle generation and renewables. As shown in Figure 4-4 this lower coal generation will support 28 GW fewer coal-fired units than in the Reference Case. About 50 percent of this decline occurs between 2020 and 2022 as the CPP starts implementation and the remainder occurs between 2022 and 2030 as the mass caps continue to decline to meet the final 2030 cap limitation.

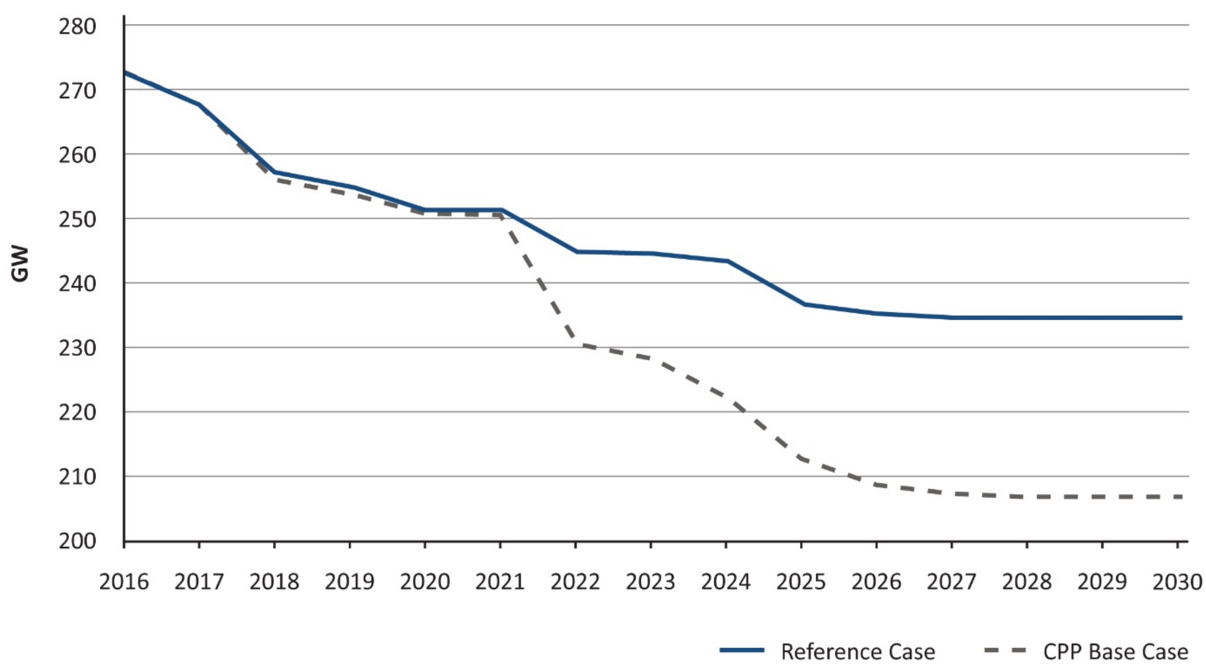

Figure 4-4: Coal Generation – AURORAxmp Model

These additional coal unit retirements (86 percent) will be heavily concentrated in SERC and MRO (primarily PJM). The following Table 4-1 shows coal-fired capacity and coal retirements in both the Reference Case and CPP Case by Region under the IPM model.

Table 4-1: Coal-fired Capacity in 2030 by Region and Cumulative Coal Retirements (MW) IPM Model

MW	Reference Case		CPP Case	
	Coal-fired Capacity	Coal Retirement	Coal-fired Capacity	Coal Retirement
FRCC	7,796	1,458	7,035	2,219
MRO	36,809	8,978	32,634	13,160
NPCC	992	2,768	1,284	2,474
RF	49,840	5,472	46,516	9,700
SERC	68,230	16,436	56,848	27,815
SPP	22,071	3,127	20,419	4,791
TRE	14,154	5,679	13,801	6,033
WECC	22,195	8,672	19,519	11,348
US Total	222,087	52,589	198,056	77,540

Natural Gas

Initially, natural gas combined-cycle capacity will increase by 10 GW over the Reference Case as new gas is built to displace a portion of the retiring coal capacity. This capacity expansion is also concentrated in MISO, SERC and PJM—the same areas that experience the largest amount of coal unit retirements. Natural gas capacity by assessment area is shown in Table 4-2.

Table 4-2: CCGT Capacity (MW) - AURORAxmp, Year 2030

	Reference Case	CPP Base Case
ISO-NE	16,240	16,240
NYISO	15,533	16,436
PJM	38,531	42,106
MISO	32,197	35,777
FRCC	32,079	30,347
SERC	38,186	39,578
SPP	11,736	11,736
ERCOT	42,108	38,866
WECC	61,569	59,816

However, given a significant drop in power demand from improved efficiency measures enacted because of the CPP, new natural gas combined-cycle capacity builds slow to 6 GW between 2025 and 2030 (vs 13 GW in Reference Case) and 4 GW fewer gas turbines would be built by 2030 when compared to the AURORAxmp Reference Case.

Nuclear

Nuclear experiences no significant changes. Outside the 5 nuclear plants already in the development pipeline, the capital costs for new nuclear power plants remain too high to make new builds attractive, even with the creation of a new carbon penalty.

Renewables

Wind and utility-scale solar show a 22 GW increase by 2030 in the AURORAxmp CPP Base Case versus the AURORAxmp Reference Case. The vast majority of this occurs after 2022 when the 5 percent renewable set-aside incentive is in place. The additional renewable capacity will be concentrated in MISO (47 percent of the additional renewable capacity) and SPP (39 percent) and to a smaller extent ERCOT (10 percent). This concentrated renewable activity results from a combination of high carbon allowance prices that make the set-asides more attractive and better wind output, making its production costs much less than other Regions. As shown in Figure 4-5, the vast majority of this incremental CPP-related capacity would be new wind capacity.

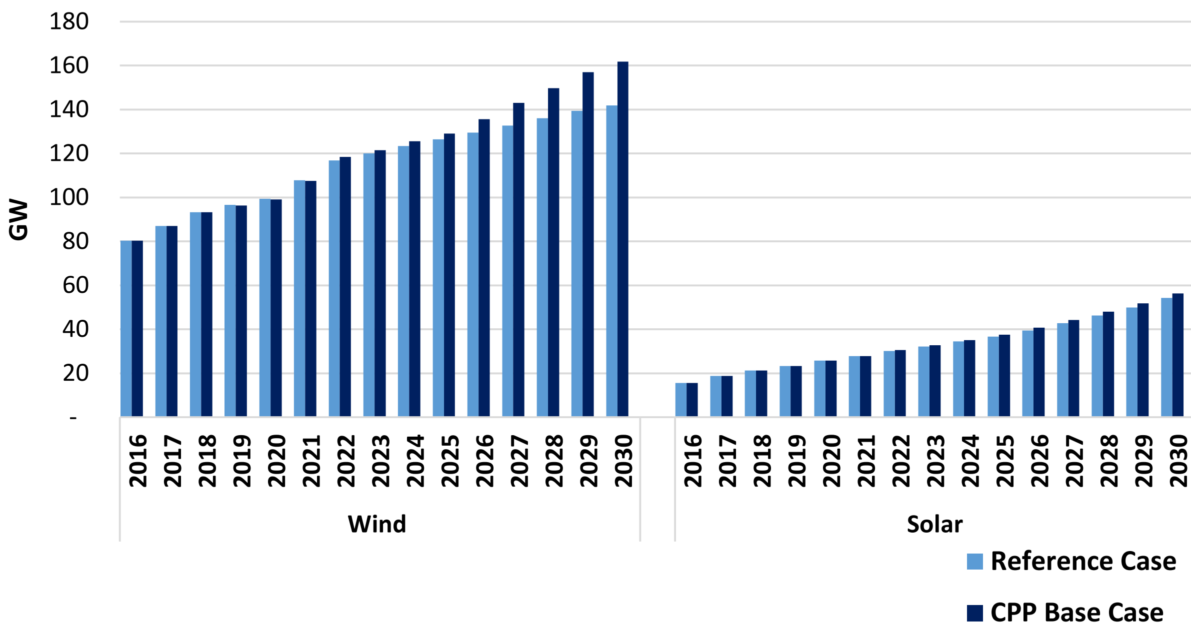

Figure 4-5: Wind and Solar Capacity – AURORAxmp Model

The increasing share of variable wind and solar generation is projected to reach 36 percent of the total generation in SPP for 2030, 31 percent in ERCOT, and 16 percent in MISO. Total wind and solar capacity for the Reference Case and CPP Base Case are shown in Figures 4-6 and 4-7.

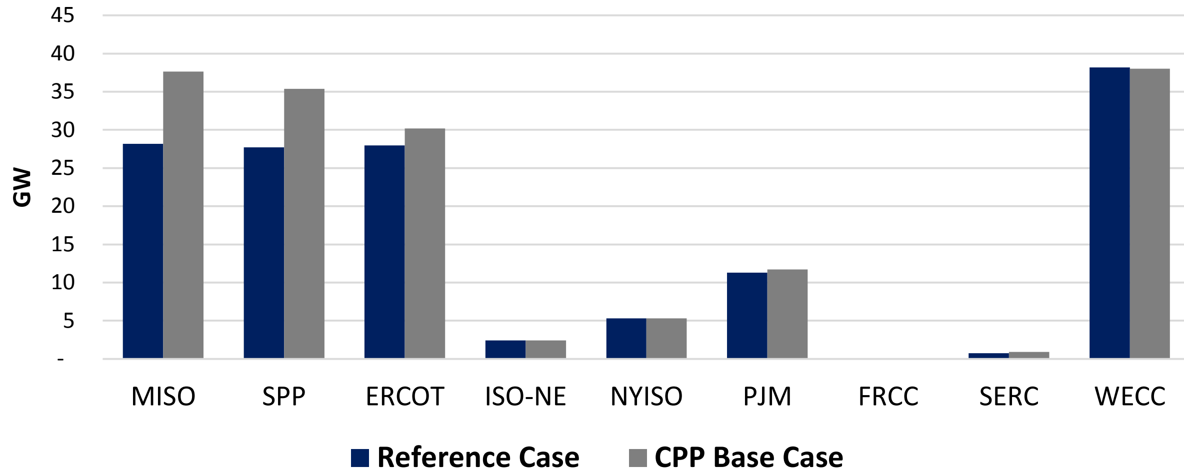

Figure 4-6: Wind Capacity in 2030, AURORAxmp Model

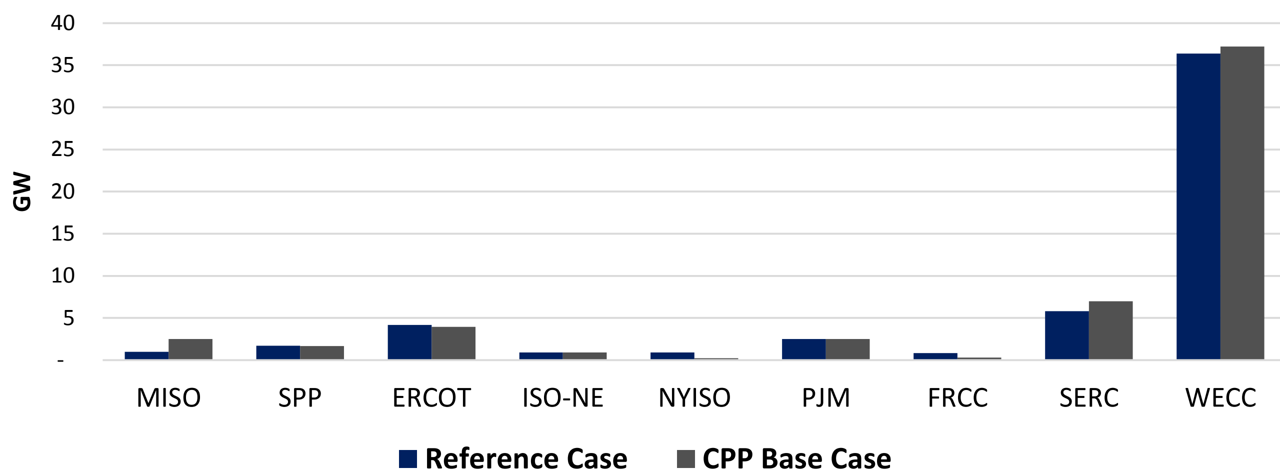

Figure 4-7: Solar Capacity in 2030, AURORAxmp Model

Summary

The largest differences in the Reference Case versus the CPP Base Case are the decline of coal generating capacity and the increase in renewable generation. Demand price elasticity and energy efficiency, as a result of the CPP, constrain growth in consumption to a level where load growth is lower in the CPP Base Case than the Reference Case. Natural gas has small changes and nuclear has no significant changes. Wind and solar increase in the CPP Base Case after the expiration of the PTC and ITC in large part due to the state RPS requirements and the CPP renewable set asides. Figure 4-8 shows the overall resource mix in 2016 and 2030 in the Reference Case as compared to the CPP Base Case.

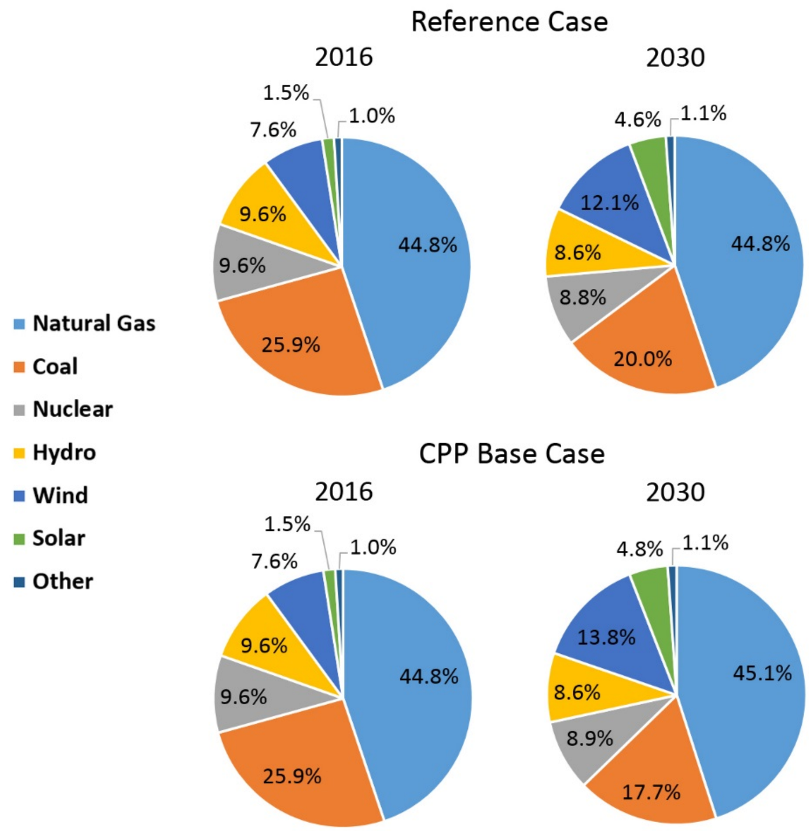

Figure 4-8: Percent Capacity Mix – AURORAxmp Model

Resource Mix - Generation (GWh)

To meet the shrinking CO_2 mass limitations, power suppliers will need to displace higher CO_2-emitting coal-fired generation with a combination of enhanced energy efficiency measures, lower carbon-emitting generation (from both affected and nonaffected sources (e.g., new CCGT and imports), and renewables. Improved energy efficiency measures play the most dominant role in coal generation displacement under the CPP. As the mass limitations shrink from 2022 to 2030, expanding the energy from CCGT and renewable generation to displace additional coal-fired generation (GWh) become increasingly important.

Coal

The AURORAxmp CPP Base Case and the IPM CPP Base Case generate similar trends and results as compared to their Reference Cases. Coal experiences a significant decline in GWh versus the Reference Case. By 2030, approximately 375 TWh less coal is used. This is a direct result of CPP compliance resulting in a lower net energy for load in the CPP Cases. Roughly 76 percent of these incremental coal losses are concentrated in MISO, SERC and PJM with an additional 11 percent CPP-related coal generation losses in SPP. These large generation mix shifts in these three areas highlight the importance of increased energy efficiency and building new replacement capacity quickly to maintain system reliability. Figures 4-9 and 4-10 show the decrease in coal generation (TWh) in the CPP Base Case versus the Reference Cases.

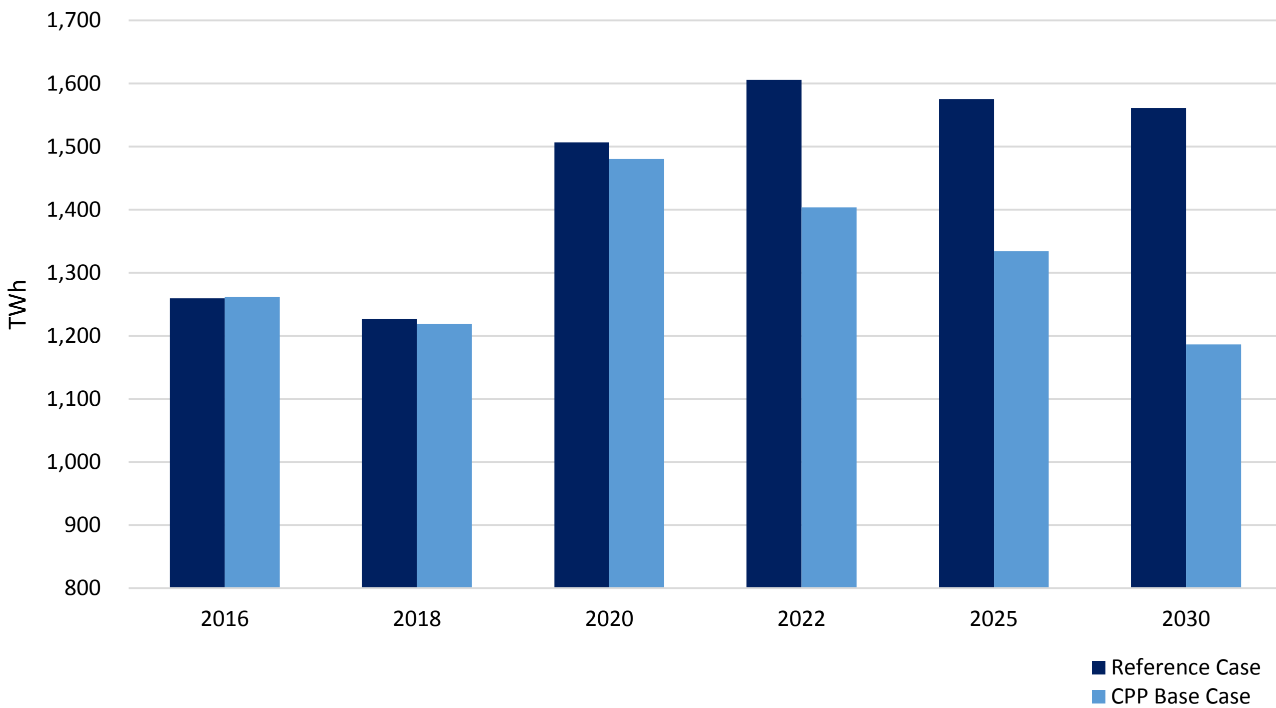

Figure 4-9: Coal Generation (TWh) - AURORAxmp Model

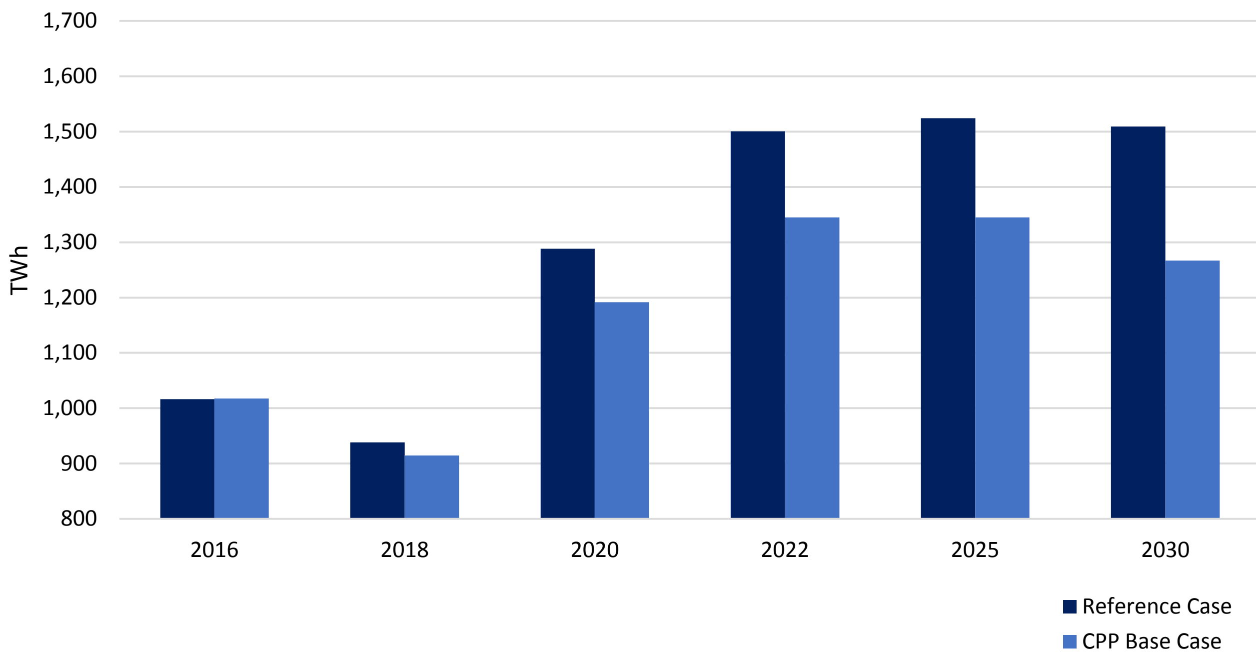

Figure 4-10: Coal Generation (TWh) -IPM Model

Natural Gas

In the CPP Base Cases, the same trend of increased gas use is also observed. Natural gas combined-cycle generation increases by approximately 87 TWh by 2030, compared to the Reference Case, to displace coal-fired generation that is needed to meet the mass limitations. This Natural gas combined cycle (NGCC) generation increase is completely dominated by three areas (MISO, SERC, and PJM) that see a 93 TWh increase in NGCC generation by 2030. However, a portion of this increase is offset by lower NGCC generation in both ERCOT and

WECC (specifically AZ-NM-SNV) that is lost from energy efficiency program expansion promoted by the CPP. Figure 4-11 shows the change in natural-gas-fired utilization as a result of the CPP.

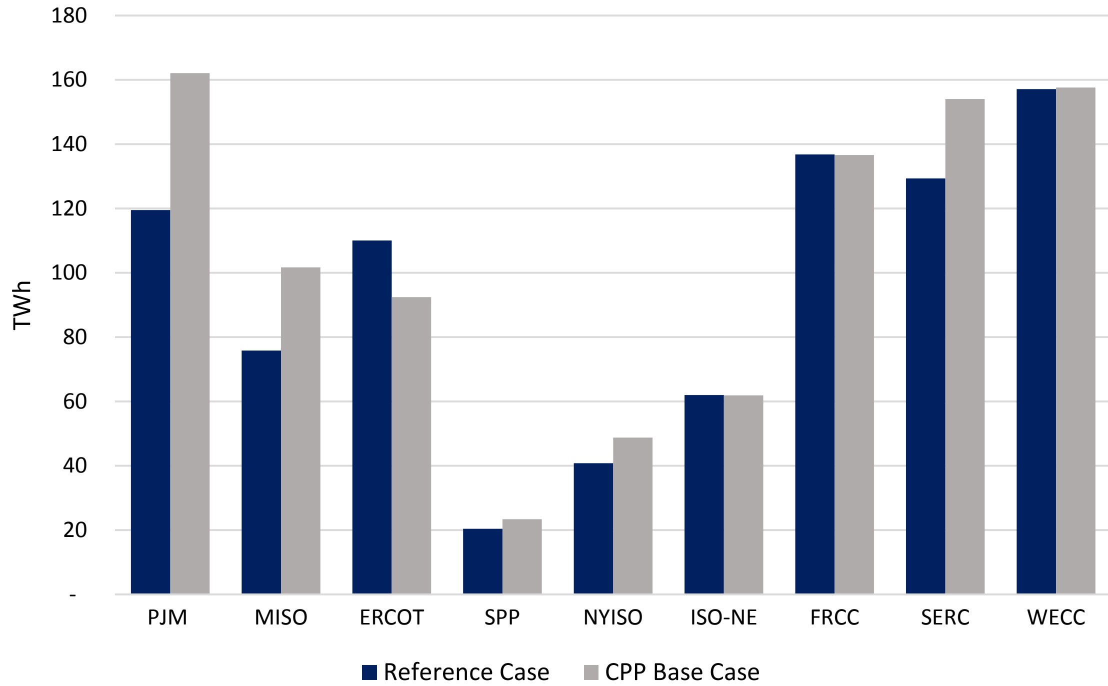

Figure 4-11: CCGT Generation in 2030, AURORAxmp Model

Nuclear

Nuclear utilization remains relatively flat in the CPP Base Cases versus the Reference Case since wholesale power prices are insufficient to justify building new nuclear capacity beyond the five projects in the development pipeline.

Renewables

Renewable generation in GW hours increases significantly for wind and, to a far lesser extent, for utility-scale solar in the CPP Base Case versus the Reference Case. This expansion is solely attributable to the set aside incentives and higher wholesale power prices from the CPP. Nearly 97 percent of this incremental renewable generation created by the CPP will be concentrated in MISO (48 percent), SPP (39 percent) and ERCOT (10 percent). The increase in renewables in these areas as a result of the CPP is shown in Figures 4-12 and 4-13.

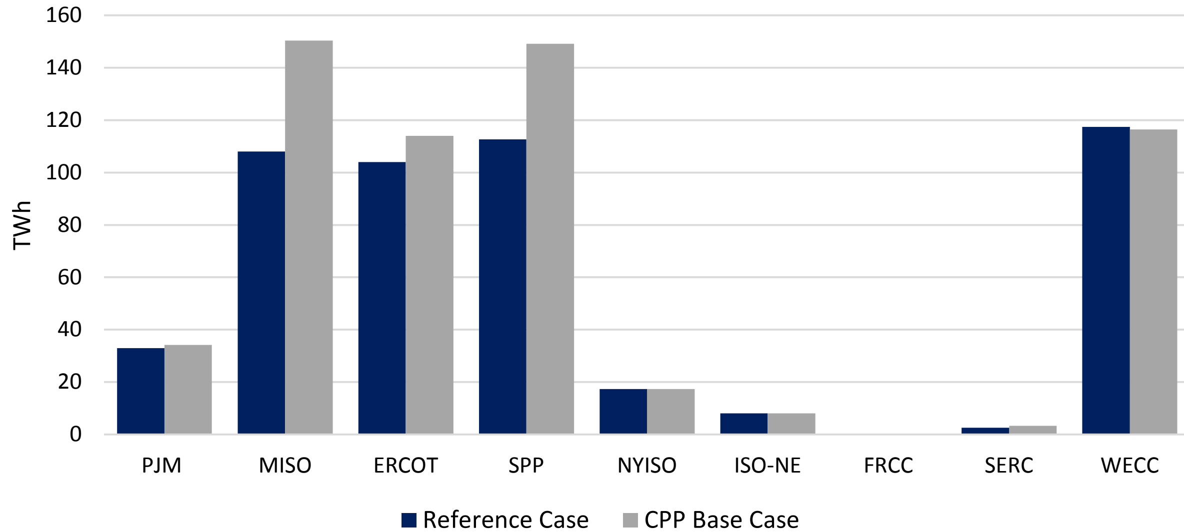

Figure 4-12: Wind Generation in 2030, AURORAxmp Model

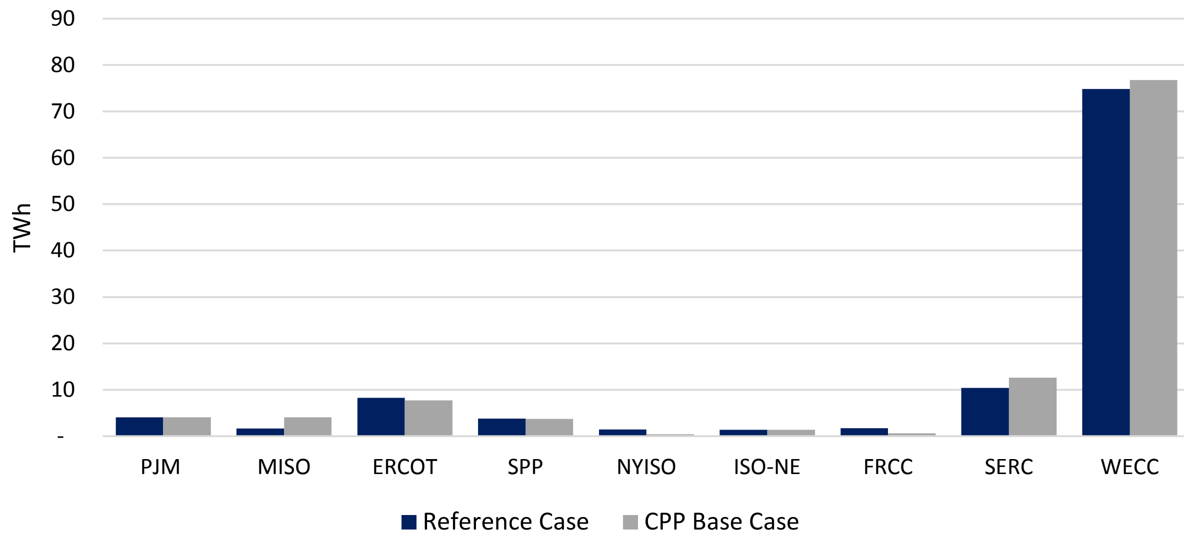

Figure 4-13: Solar Generation in 2030, AURORAxmp Model

The changes in overall generation (GWh) as a result of the CPP are shown in Figure 4-14 below.

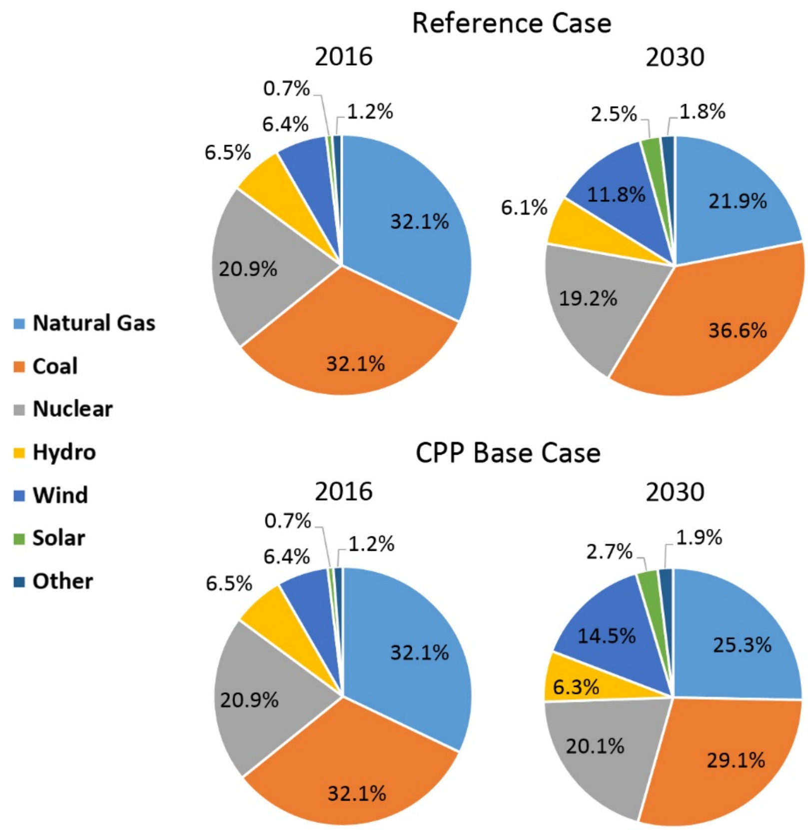

Figure 4-14: Percent Generation Mix, AURORAxmp Model

Chapter 5: National Trading

Under the EPA CPP, states have the flexibility to join multistate trading programs. By expanding allowance trading beyond state borders, compliance can be optimized over the lower 48 states with significant savings for states that have high marginal compliance costs. These states could purchase surplus allowances from states with lower marginal costs. Power suppliers operating in multiple states may be able to not only optimize their compliance costs across their entire system but also find system operations easier. Importantly, interstate trading allows some states with growing allowance surpluses to sell them to states in lieu of banking them. These surplus allowance credits total roughly 70–100 million tons/year. The purpose of this sensitivity case is to identify how compliance and power flows change with national interstate trading and the consequential effect on reliability.

The National Trading Case makes the assumption that each state will optimize its trading potential of emission allowances with other states in order to comply most economically, which will serve to lower retirements and new builds.

The models indicate that national trading of allowances would result in more coal utilization. Increased emissions from coal would be offset by renewables and natural-gas-fired generation. More coal facilities will stay operational in the CPP National Trading Cases and less gas facilities will be built. Additionally, the BPS will experience higher utilizations of coal and renewable energy under a National Trading Case. As allowances are optimally traded among states, higher levels of coal generation are offset by higher levels of renewable generation in the overall carbon emissions paradigm. Figure 5-1 shows carbon prices by state in the CPP Base Case versus the National Trading Case, highlighting the ability for states to trade with one another and reduce their overall compliance costs.

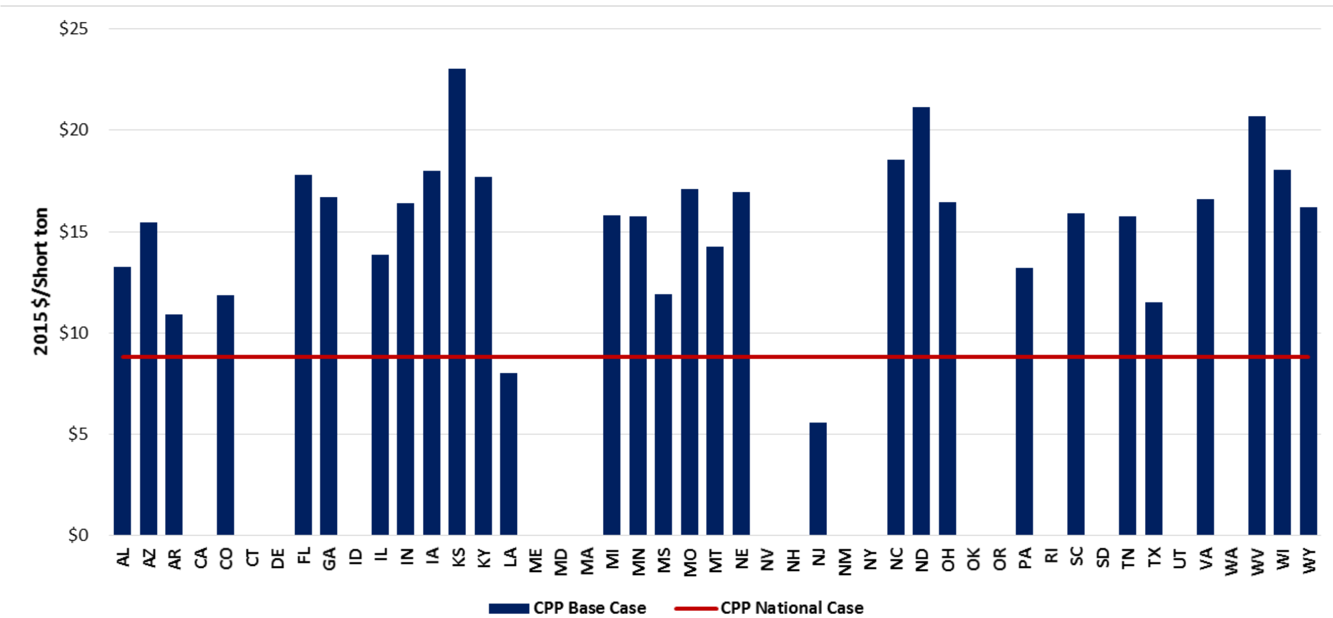

Figure 5-1: 2030 CO_2 Allowance Prices – AURORAxmp Model

Capacity Effects of National Trading Case (GW)

Coal

As is shown, national interstate trading should reduce coal-fired unit retirements by approximately 10 GW in 2025 and 4 GW less in 2030 versus the CPP Base Case. This is highlighted in Figure 5-2.

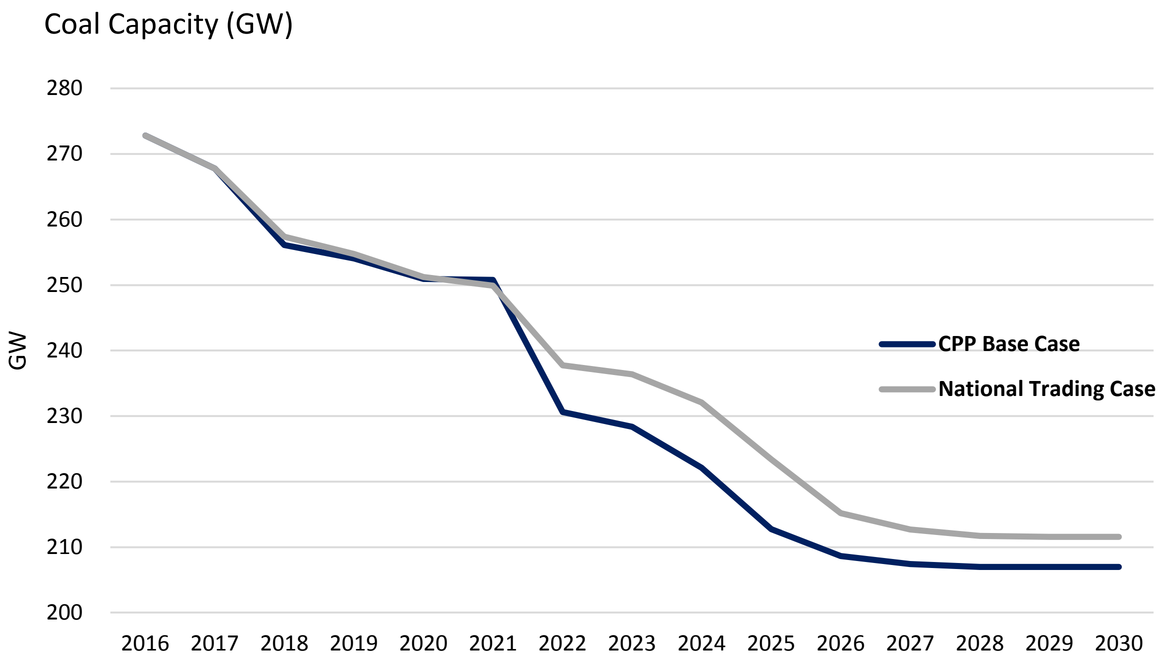

Figure 5-2: Coal Capacity – AURORAxmp Model

Natural Gas

The National Trading Case has a modest effect on the overall level of natural gas combined-cycle capacity when compared to the CPP Base Case. As is shown in Figure 5-3, given the fewer coal unit retirements, less new natural gas combined-cycle capacity is needed. In addition, national trading will support far less oil/gas steam unit capacity (6,344 MW by 2030), which also results in a small drop in system capacity.

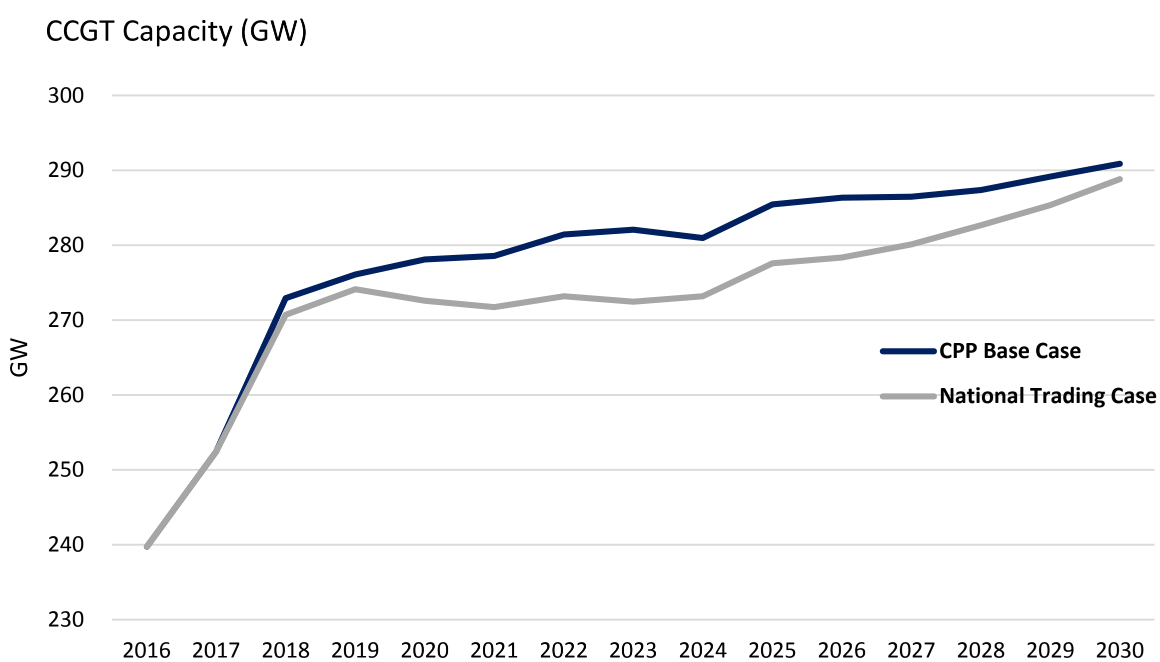

Figure 5-3: CCGT Capacity –AURORAxmp Model

Nuclear

The National Trading Case has no effect on the overall level of nuclear capacity when compared to the CPP Base Case.

Renewable

As shown in Figures 5-4 and 5-5, national trading has only a small effect on the overall needed renewable capacity needs. However, there are differences in where this capacity is placed. In a National Trading Case, the value of the renewable set-aside rises in states that had low marginal compliance costs (in the CPP Base Case). These states can now trade their surplus credits at a higher price to high marginal cost states.

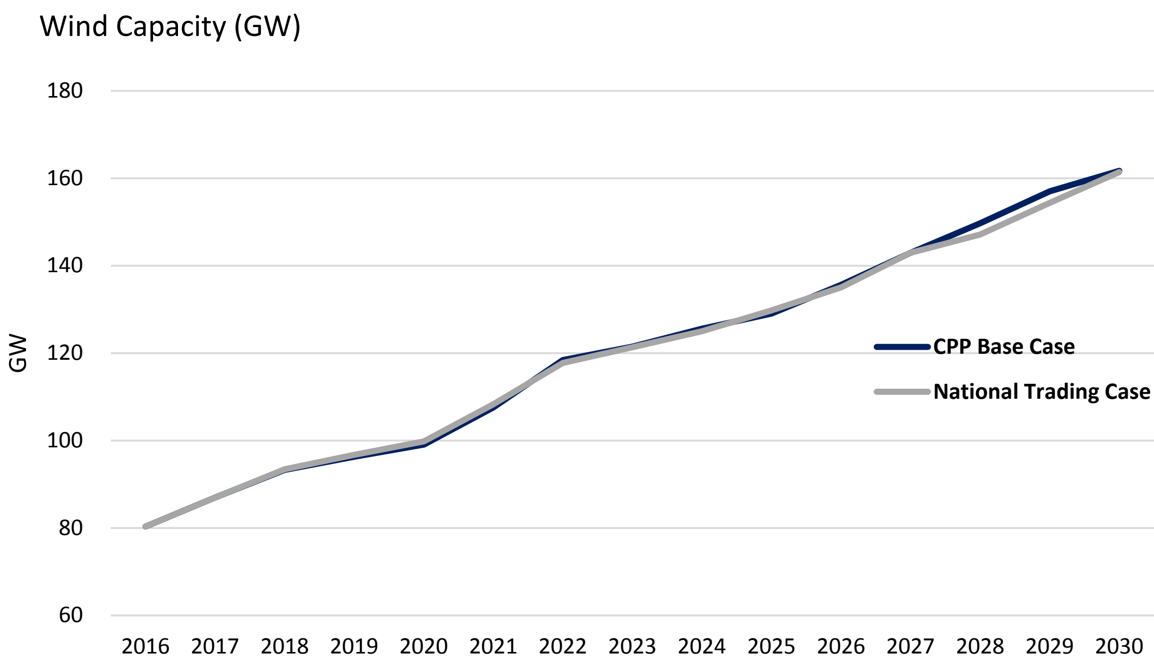

Figure 5-4: Wind Capacity (GW) – AURORAxmp Model

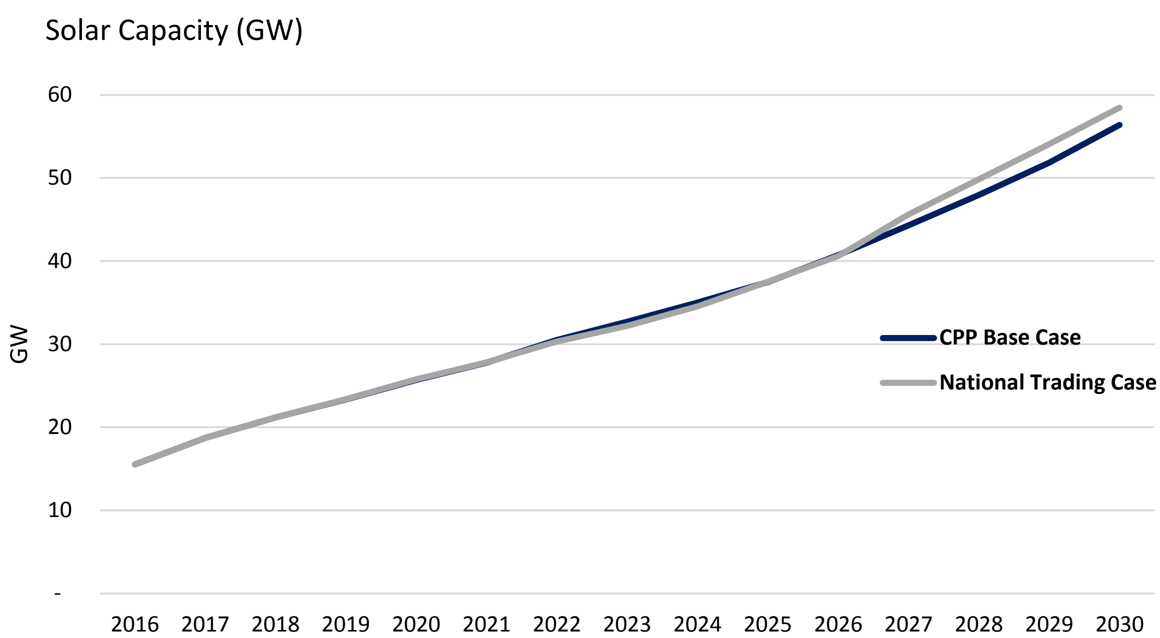

Figure 5-5: Solar Capacity (GW) –AURORAxmp Model

Summary
A trading market that becomes fully optimized and maximizes the trading of allowances to its fullest extent provides an opportunity to achieve compliance while retiring less coal and building less natural-gas-fired resources as compared to the CPP Base Case. The overall resource mix in the optimized National Trading Case versus the CPP Base Case is demonstrated in Figure 5-6.

Both MISO-Central and PJM can benefit greatly from national trading as the surplus allowances allow them to increase their 2030 regional generation by 14 and 21 TWh versus the CPP Base Case. Most of these increases are from existing coal-fired units.

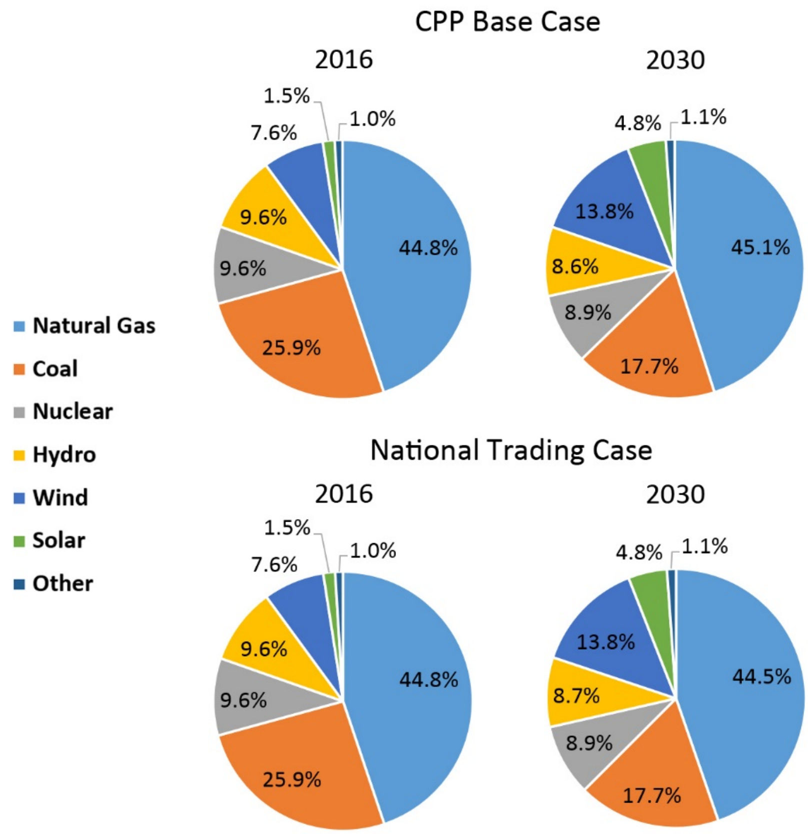

Figure 5-6: Percent Capacity Mix – AURORAxmp Model

Generation Effects of National Trading Case (GWh)
By expanding trading, several states with allowance surplus are able to trade them to states with high marginal costs and realize additional revenues not possible in the CPP Base Case. Overall, affected unit emissions are 70–100 million tons/year higher in the National Trading Case. Also importantly, the power flows do change between these 2 cases as trading between high and low marginal cost states increases. The changes in 2030 regional imports and exports from nearby areas as a result of expanded interstate trading are shown in Figure 5-7. While the aggregate generation changes are more modest since coal still needs to be displaced to meet the CPP requirements, the power flow changes in MISO, PJM and WECC show the importance of trading to regional power flows.

	Imports				Exports			
	Base CPP	Natl Trading		% Change	Base CPP	Natl Trading		% Change
Total	72,330	70,187	(2,143)	-3.0%	24,369	25,281	912	3.7%
MISO	149,632	144,375	(5,256)	-3.5%	135,835	129,041	(6,794)	-5.0%
MISO-North	*31,773*	*29,099*	*(2,674)*	*-8.4%*	*72,353*	*66,553*	*(5,799)*	*-8.0%*
MISO-Central	*105,670*	*86,872*	*(18,798)*	*-17.8%*	*113,509*	*109,103*	*(4,406)*	*-3.9%*
MISO-South	*66,898*	*77,999*	*11,101*	*16.6%*	*4,682*	*2,980*	*(1,702)*	*-36.4%*
PJM	74,676	50,883	(23,793)	-31.9%	42,347	40,276	(2,071)	-4.9%
SERC	90,771	90,744	(27)	0.0%	68,704	69,790	1,086	1.6%
SERC-North	*74,230*	*81,236*	*7,005*	*9.4%*	*64,188*	*67,783*	*3,595*	*5.6%*
SERC-East	*18,706*	*11,028*	*(7,678)*	*-41.0%*	*1,744*	*3,797*	*2,053*	*117.7%*
SERC-SouthEast	*18,582*	*20,849*	*2,267*	*12.2%*	*23,520*	*20,578*	*(2,941)*	*-12.5%*
SPP	10,809	10,302	(507)	-4.7%	64,865	66,008	1,143	1.8%
ERCOT	2,084	2,665	581	27.9%	3,260	2,564	(696)	-21.4%
FRCC	20,739	18,757	(1,982)	-9.6%	82	46	(36)	-43.7%
NYISO	16,135	18,129	1,994	12.4%	16,475	11,494	(4,980)	-30.2%
ISONE	19,754	22,052	2,298	11.6%	3,345	2,532	(813)	-24.3%
WECC	10,179	16,444	6,265	61.5%	12,090	7,877	(4,213)	-34.8%
WECC-CAMX	*66,216*	*76,818*	*10,602*	*16.0%*	*775*	*759*	*(16)*	*-2.1%*
WECC-NWPP	*23,978*	*30,073*	*6,095*	*25.4%*	*48,353*	*47,209*	*(1,144)*	*-2.4%*
WECC-AZNMSNV	*5,470*	*4,872*	*(598)*	*-10.9%*	*31,078*	*39,976*	*8,898*	*28.6%*
WEC-RMPA	*1,591*	*2,607*	*1,016*	*63.9%*	*18,960*	*17,860*	*(1,100)*	*-5.8%*

Figure 5-7: Regional Imports and Exports, AURORAxmp Model

Coal

Coal use is most affected by broad interstate trading. By allowing expanded interstate trading, states with growing allowance surpluses will be able to sell their allowances (70–100 million tons/year) to the high cost states and support some 100–130 TWh of increased coal generation. These increases are concentrated in the coal-heavy areas of PJM, SERC, and MISO.

Natural Gas

Likewise, the surplus allowances will back out some high marginal cost switching from coal to natural gas combined-cycle generation, especially in MISO (24.5 TWh), PJM (21.5 TWh) and SERC (14.5 TWh). Overall, 80-100 TWh less energy from gas-fired combined-cycle generation capacity is required.

Nuclear

Nuclear demonstrates no effect in the National Trading Case versus the CPP Base Case. Nuclear capital costs remain too high and wholesale power prices too low to support any additional nuclear construction.

Renewables

The National Trading Case demonstrates only small changes in wind and solar generation as most surplus allowances are consumed to back out coal to gas generation shifting. However, there are two areas that generate slightly more wind by 2030 versus the CPP Base Case (ERCOT 11.9 TWh, PJM 1.4 TWh). These renewable increases offset some renewable generation losses in MISO (14.5 TWh) and SPP (2.1 TWh). Figure 5-8 shows the difference in generation (GWhs) as a result of national trading versus the CPP between major regions.

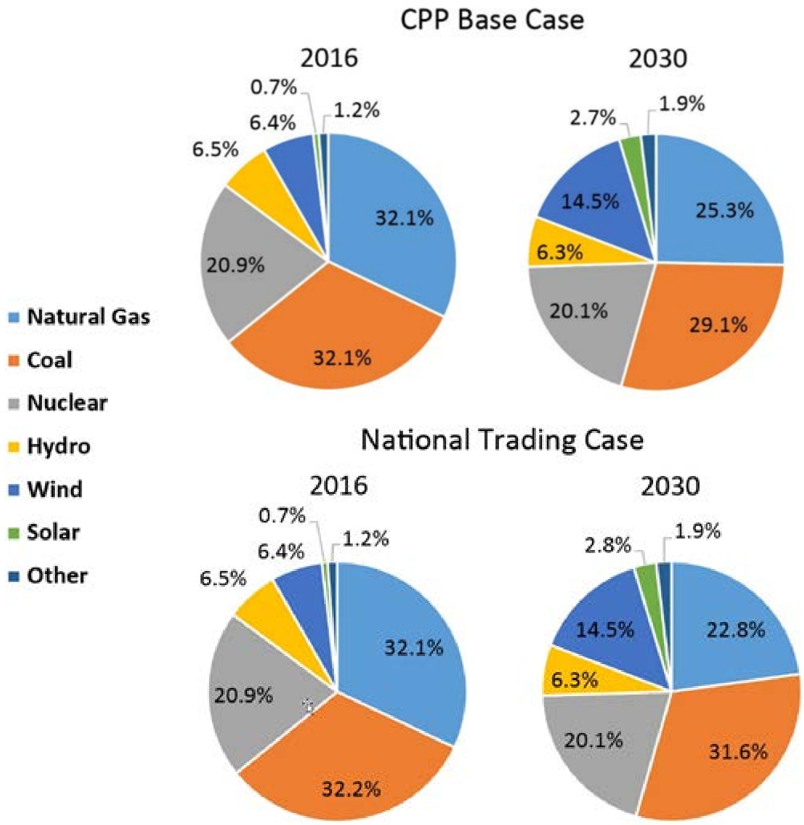

Figure 5-8: Percent Generation Mix, AURORAxmp Model

Reliability Issues

National trading provides an opportunity for more coal generation versus the CPP Base Cases, demonstrating less need for natural gas combined-cycle and renewable generation. To what extent trading develops on a national scale and its timing will dictate whether trading can be relied on to help meet CPP compliance. Past national emission trading programs such as Title IV and Cross State Air Pollution Rule (CSAPR) have been more limited.[17] The National Trading Case assumes full optimized trading so it is more likely that actual CPP trading will fall somewhere in between the CPP Base Case and the CPP National Trading Case. From a reliability stand point, it will be important that states plan accordingly for trading and properly account for what can adequately be relied on from a trading stand point to meet their emissions reduction goals.

[17] https://www.epa.gov/clean-air-act-overview/title-iv-noise-pollution; https://www3.epa.gov/crossstaterule/

Chapter 6: High Renewable Penetration Case

Capacity (GW)

Given the critical need to provide ERSs to support grid reliability, a sensitivity case was developed to identify the potential reliability issues associated with more renewable generation expansion. Given that wind and solar PV competiveness are most heavily tied to their initial capital costs and output performance, a high renewable technology improvement case was selected that used NREL developed high penetration projections and high performance projections.[18] This low-cost renewable case assumes that renewables will have both lower technological development costs as well as lower O&M costs and increased performance. [19]

Overall, both models build between 140 and 164 GW of renewable capacity by 2030 from 2016 levels, 70 percent of which is wind capacity. Compared to the CPP Base Case, the models build an additional 26 to 28 GW by 2030 in the High Renewable Penetration Case. These incremental builds will occur in Regions with considerable renewable generation because of their higher quality wind resources and, to a lesser extent, higher solar radiation. About 60 percent of this additional renewable energy capacity is located in the MISO-North and MISO-Central regions. Other significant amounts of additional renewable energy builds are projected to occur in SPP (12 percent), ERCOT (14 percent), and WECC-California (7 percent). The incremental expansion is heavily slanted towards the end of the forecast period as the mass limitations shrink. The increases are still modest since the industry reached its projected planning/permitting/construction limits throughout the concentrated areas in the CPP Base Case. Figures 6-1 and 6-2 show the levels of renewable builds in the High Renewable Penetration Case versus the CPP Base Case.

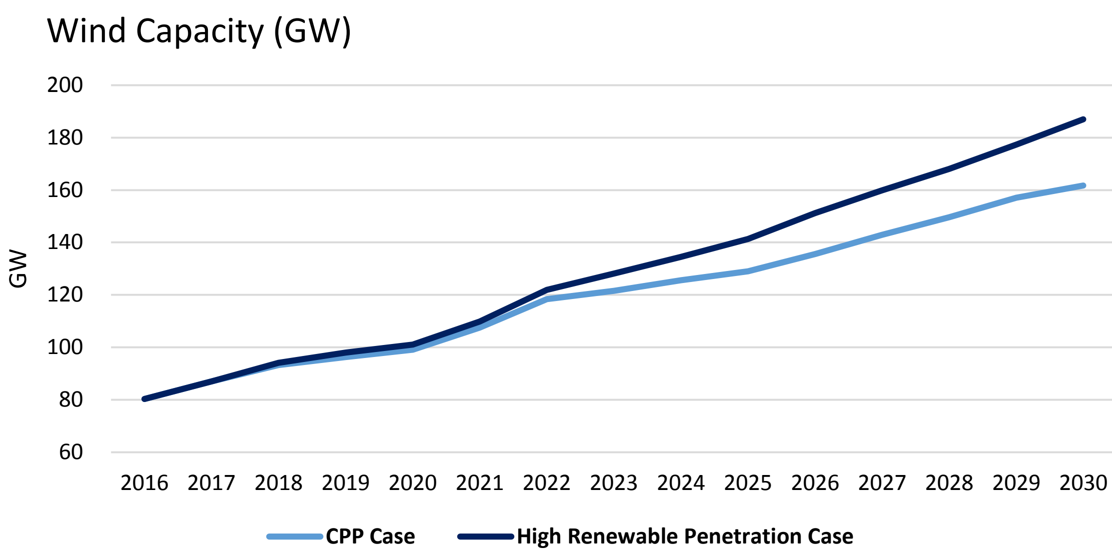

Figure 6-1: Wind Capacity (GW), AURORAxmp Model

[18] http://www.nrel.gov/docs/fy16osti/64720.pdf

[19] A full description of the cost assumptions for the High Renewable Penetration case is included in the appendix

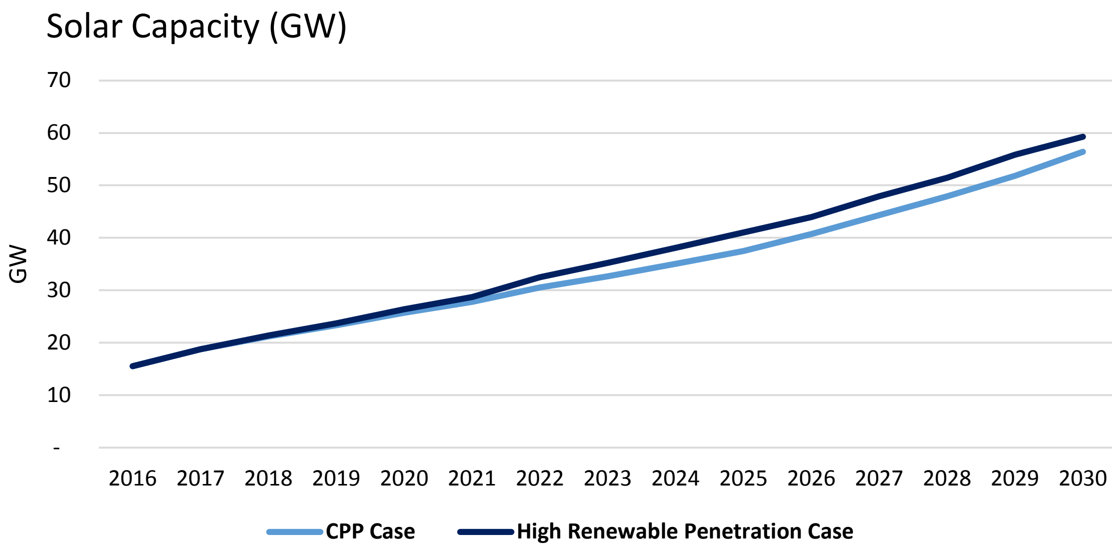

Figure 6-2: Solar Capacity (GW), AURORAxmp Model

Coal

The High Renewable Penetration Case has little noticeable effect on coal unit retirements. This is directly attributable to the regions in which the renewable expansion is concentrated and projected rising natural gas prices placing more CCGT capacity on the margin.

Natural Gas

Due to the higher renewable capacity in the MISO, ERCOT, and WECC-California markets, slightly less new CCGT capacity is being built to meet reserve margin targets. Overall, in the High Renewable Penetration Case, the models build 2-7 GW less new CCGT capacity by 2030, totaling 283 GW of CCGT capacity in the market.

Nuclear

Nuclear generating capacity shows no change in the models in the low-cost renewables case versus the CPP Base Case.

Summary

While the investment tax credit and production tax credit, in combination with lower capital costs and higher performance rates, provide significant stimulus to develop renewable resources prior to the CPP taking effect in 2022, most of the additional renewable capacity under this case is being built in the second half of the 2020s. As a result, areas such as MISO-North and MISO-Central will experience renewable build-outs that come close to the maximum build-out potential based on historical build levels. This large increase in renewables will result in potential reliability challenges in terms of making sure that these resources can provide the requisite ERSs such as frequency response, voltage support, and ramping capability. Less CCGT capacity in areas with accelerated renewable capacity build-outs also means less load-following and backup capacity available, adding to potential reliability issues. Figure 6-3 shows the overall resource mix in the High Renewable Penetration Case.

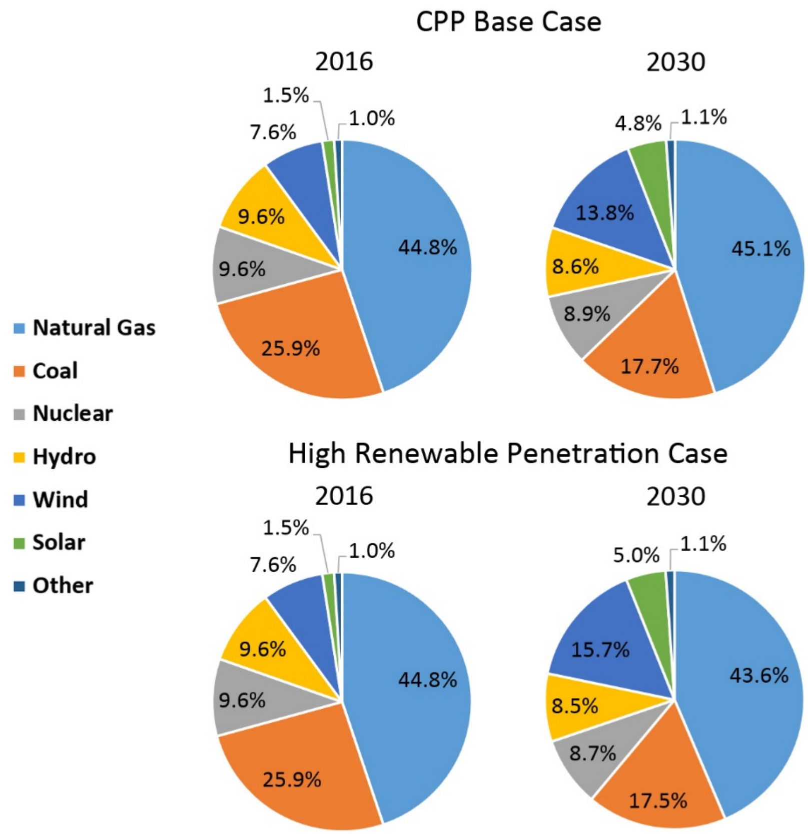

Figure 6-3: Percent Capacity Mix, AURORAxmp Model

Generation (GWhs)

Corresponding to the additional renewable energy capacity in the High Renewable Penetration Case, renewable generation also increases significantly. By 2030, generation from renewable energy sources will increase by almost 20 percent over the CPP Base Case. As is true for the capacity build-out, most of the generation increases are concentrated in MISO-North and Central, SPP, ERCOT, and WECC Regions. More than 50 percent of the renewable energy generation increase is located in just two Regions: MISO-North and MISO-Central. While MISO-North's renewable energy generation increases by more than 50 percent, MISO-Central's renewable energy generation more than doubles compared to the CPP Base Case, making it the Region with the highest absolute increase in renewable energy generation.

Higher renewable generation in a Region's dispatch stack lowers overall wholesale power prices due to its low variable and nonexistent fuel cost. Lower wholesale power prices in MISO-North and Central result in reduced power imports from Canada by almost 10 percent and increased power exports of more than 30 percent to Canada when comparing to the CPP Base Case. Figure 6-4 shows imports and exports from Canada and other Regions in the CPP Base Case versus the High Renewable Penetration Case.

		CPP Case	High Renewable Penetration Case
Into	From	2030	2030
CAN	ISONE	43	61
CAN	MISO	1,512	2,692
CAN	MRO	24	57
CAN	NYISO	462	224
CAN	WECC	638	517
ERCOT	SPP	238	148
FRCC	SERC	2,367	2,731
ISONE	CAN	1,660	1,675
ISONE	NYISO	595	705
MEX	WECC	102	108
MISO	CAN	4,433	3,208
MISO	MRO	1,434	1,696
MISO	PJM	3,051	2,969
MISO	SERC	5,230	5,559
MISO	SPP	2,932	3,587
MRO	CAN	39	18
MRO	MISO	1,215	1,796
MRO	SPP	6	6
MRO	WECC	369	274
NYISO	CAN	1,160	1,309
NYISO	ISONE	338	279
NYISO	PJM	344	435
PJM	MISO	7,566	10,265
PJM	NYISO	824	497
PJM	SERC	135	102
SERC	FRCC	9	3
SERC	MISO	4,802	6,644
SERC	PJM	1,439	1,615
SERC	SPP	4,112	4,765
SPP	ERCOT	372	496
SPP	MISO	412	418
SPP	MRO	70	108
SPP	SERC	110	70
SPP	WECC	270	188
WECC	CAN	603	898
WECC	MEX	363	338
WECC	MRO	80	210
WECC	SPP	117	238

Figure 6-4: Imports and Exports, AURORAxmp Model

Coal

Due to most of the remaining coal capacity in the High Renewable Penetration Case operating as baseload generation and ahead of most CCGT capacity, increased renewable generation has only a limited effect on overall coal generation. Compared to the CPP Base Case, national coal generation only declines by about 1 percent by 2030.

Natural Gas

Natural gas generation experiences the largest decline in the High Renewable Penetration Case. In most regions under the CPP, CCGT generation is operated as a load-following resource and oftentimes the marginal resource. Higher renewable penetration results in overall lower power prices (on-peak and off-peak), making it less economical for some CCGT plants to operate. By 2030, national CCGT generation is more than 115 TWh below CPP Base Case levels. While the additional renewable generation was concentrated in just a few regions, reduction in CCGT generation is more widespread, significantly affecting the regional power flows. For example, PJM's renewable energy generation under the High Renewable Penetration Case in 2030 only increases by 2 TWh, whereas its CCGT generation decreases by almost 25 TWh. Most of the lost CCGT generation is being offset by importing lower-cost renewable generation from the MISO-North and Central Regions.

Nuclear

The High Renewable Penetration Cases showed no significant difference in nuclear generation over the CPP Base Case.

Figure 6-5 shows the annual generation (GWhs) in major power pools in the High Renewable Penetration Case versus the CPP Base Case.

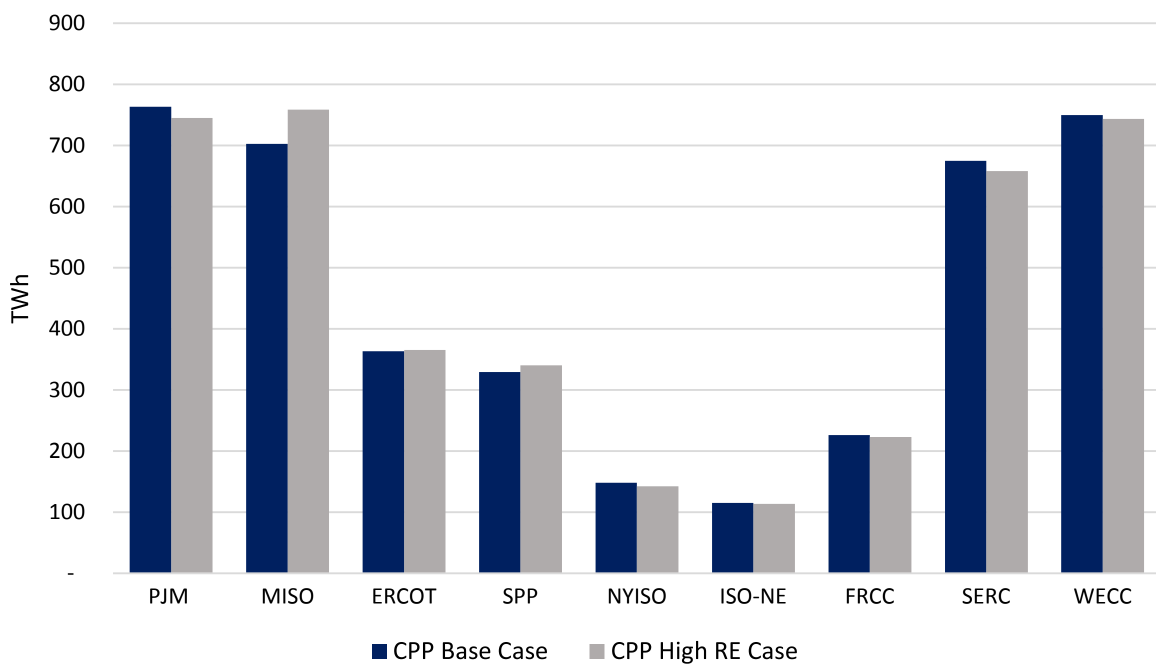

Figure 6-5: Generation in Major Power Pools in 2030, AURORAxmp Model

Reliability Implications

In the High Renewable Penetration Case lower technology costs, lower O&M costs and higher performance were assumed. These assumptions can be further reviewed in the CPP Phase II assumptions in the Appendix. While one would expect a large increase in renewable generating capacity and energy as a result of lower renewable costs, the modeling showed that the majority of renewable builds occur as a result of the ITC and PTC. Not until the expiration of the PTC and ITC does the High Renewable Penetration Case begin to build incremental renewables.

The ITC and PTC results in close to maximum build-out capability in many areas prior to their expiration.

The High Renewable Penetration Case does demonstrate that, as performance of renewables increases, renewable generation in GWhs will increase as well. Additionally, lower cost renewables will become a larger factor when the ITC and PTC expire. As a result, system planners should plan for an increase in renewables as a result of the ITC and PTC extensions and also later as a result of the CPP. This increased penetration of renewables at this scale will create the need to plan for the level of ERSs needed to maintain BPS reliability. Additionally, along with the large build-out in renewable generation there will be a need for incremental transmission. System planners must plan accordingly to build the requisite transmission in order to accommodate the large build-out in renewable resources. Figure 6-6 shows the generation mix (GWhs) in the High Renewable Penetration Case.

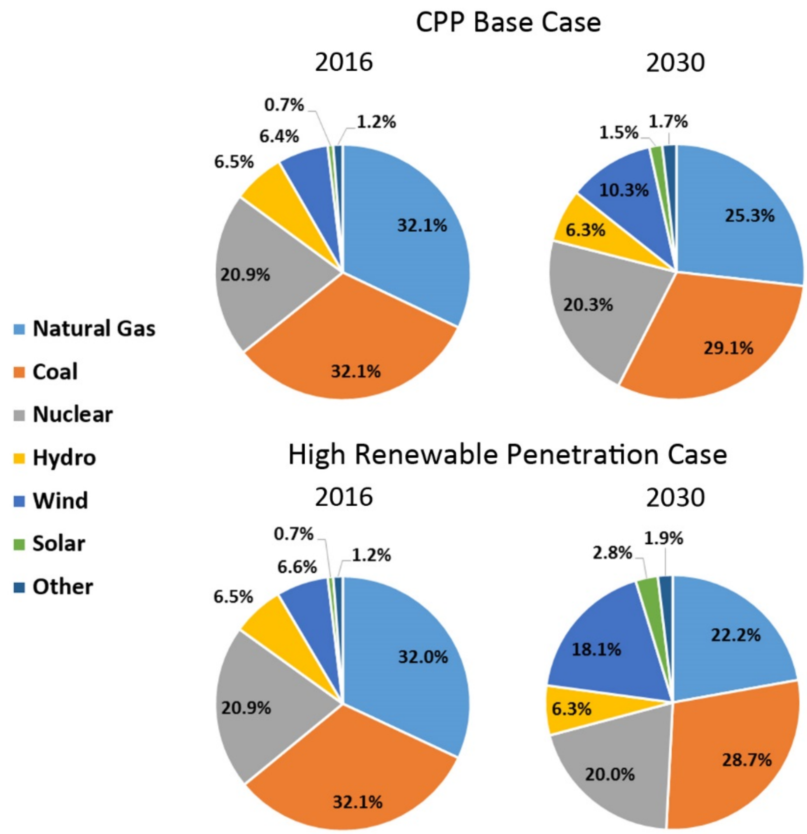

Figure 6-6: Generation Mix (GWhs) High Renewable Penetration Case AURORAxmp

Chapter 7: Accelerated Nuclear Retirements Case

Nuclear power plays an important role in reducing industry CO_2 emissions. Having no carbon emissions and very low variable costs, the nuclear fleet runs at very high capacity factors and displaces fossil fuel generation. While only a few new nuclear units are in the development pipeline, no additional units are planned to be built during the analysis period because of their very high capital cost. As the nuclear units age, industry and state regulators have begun studying how long the existing nuclear units can be kept online. The Accelerated Nuclear Retirements Case assumes that nuclear units may retire at a much earlier rate than is presently forecasted by EIA. In this case, it is assumed that nuclear units will have a 60 year useful life rather than 80 years. It also assumes that any unit not currently relicensed retires at the end of its current license. Additionally, any units that have O&M costs which are two or greater standard deviations above average will retire upon reaching that economic threshold. Additional units were identified that had capacity factor risks and a risk of not clearing its associated capacity market. These assumptions increased nuclear retirements by approximately 31 GWs between 2016 and 2030. These assumptions are more fully described in the appendix.

Capacity (GW)

The model results showed similar trends in both IPM and AURORAxmp. The projected total capacity under the Accelerated Nuclear Retirements Case for AURORAxmp is shown in Figure 7-1. This figure also quantifies the differences between the CPP Base Case and the Accelerated Nuclear Retirements Cases to highlight the sensitivity of CPP compliance strategies to nuclear plant retirements and potential changes in grid reliability impacts. Most of the incremental nuclear retirements are in the latter part of the modeling period. Given these additional nuclear retirements, the industry must shift towards more fossil fuel capacity that will require higher cost carbon reduction measures.

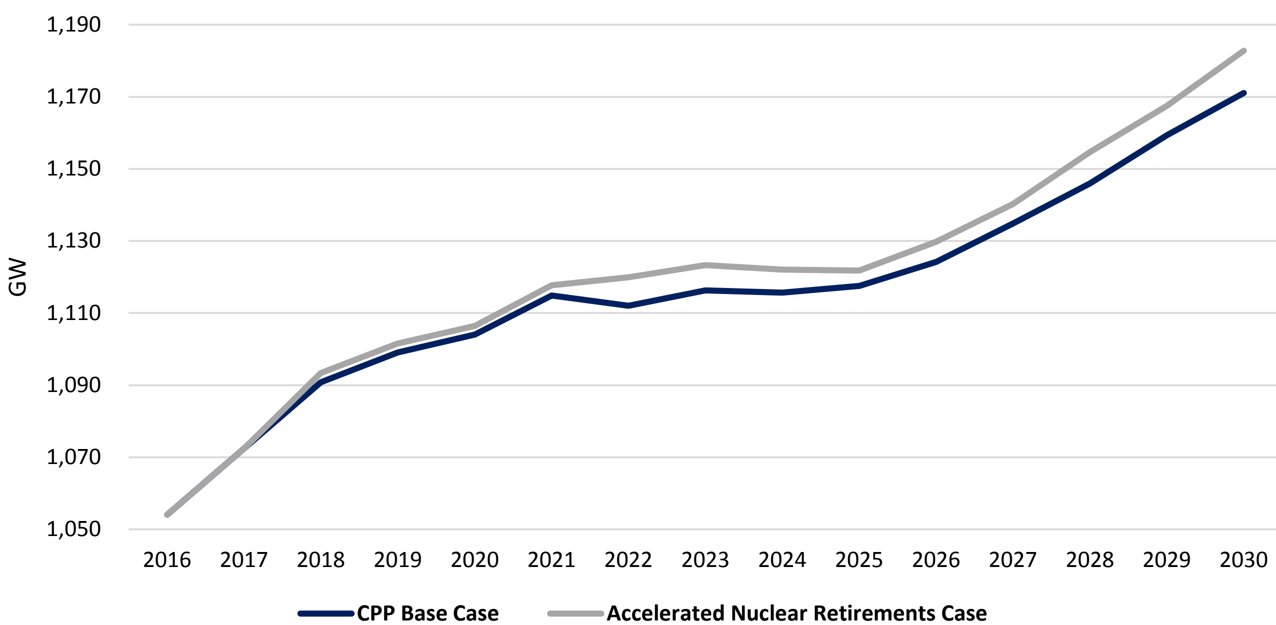

Figure 7-1: Total Projected Capacity, AURORAxmp Model

Coal

As is shown, the 31 GW in higher nuclear retirements will reduce the retirement of 10-11 GW of coal-fired capacity. Nearly 90 percent of the affected coal capacity is in PJM (6.4 GW), SERC North (1.3 GW) and WECC-NWPP (1 GW). Given that this coal-fired capacity does not need to be built, reliability impacts for these areas are less than in the regions where new capacity needs to be built to replace retiring nuclear capacity.

Natural Gas

The nuclear retirements will mostly be replaced with new gas combined-cycle capacity. Four Regions, MISO (9.5 GW), FRCC (4.3 GW), ERCOT (4.2 GW) and NYISO (2.9 GW), account for over 90 percent of this projected NGCC capacity increase. The timing for this new NGCC capacity would appear sufficient if this need is identified shortly. However, given ongoing studies and evaluations, it is uncertain when the industry will know of nuclear plant retirements and whether there will be sufficient time to build the needed new NGCC capacity and any supporting pipeline infrastructure.

Nuclear

Both models used the same assumptions for nuclear retirements and retire 31 GWs of additional nuclear by 2030 with 21 GWs of that occurring by 2025. These retirements during the forecast period are expected to be concentrated in PJM (12.4 GW), MISO (8.9 GW), ERCOT (3.8 GW) and NYISO (3.5 GW). Outside PJM, these retirements will account for 66–76 percent of the existing regional fleets. Given their size, each nuclear retirement may pose a significant reliability risk unless sufficient time is provided to plan, permit, finance, and build the replacement capacity.

Renewables

The Accelerated Nuclear Retirements Case will build additional wind capacity—primarily in MISO, SPP and ERCOT. While wind capacity generally has a much shorter development period than its fossil fuel competitors, it also requires the industry to build additional ERSs to support its growing market share.

Summary

Nuclear generating units provide a zero emitting carbon resource that serves as a very integral component of potential CPP compliance. To the extent that additional nuclear units retire the decrement in resources will need to be made up through natural gas, renewables, and delayed retirement of coal units. The resource mix comparing the CPP Base Case to the Accelerated Nuclear Retirements Case is demonstrated in Figure 7-2.

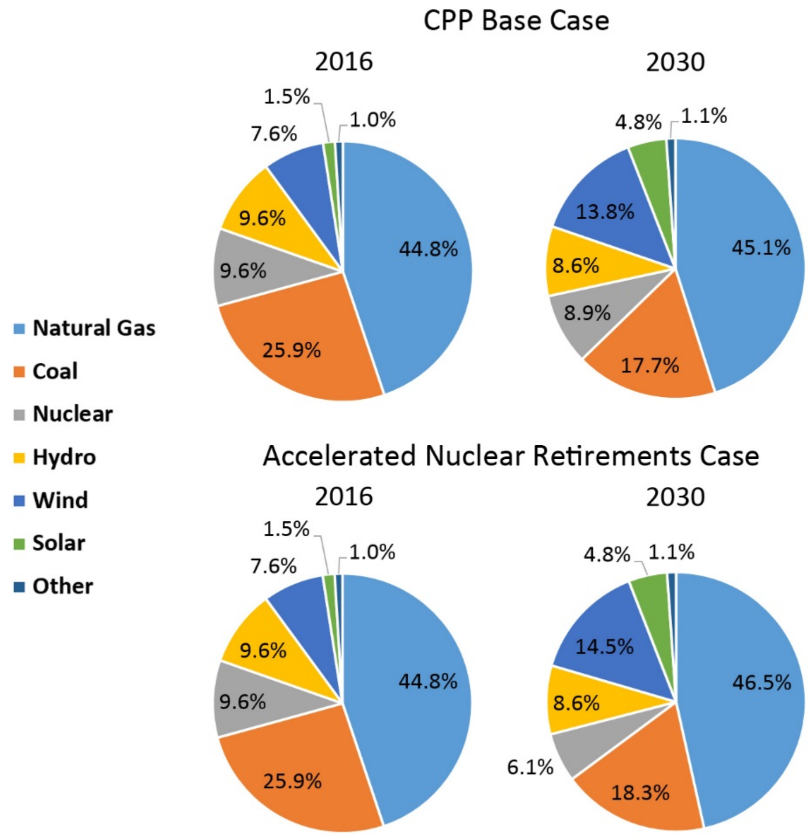

Figure 7-2: Percent Capacity Mix, AURORAxmp Model

Accelerated Nuclear Retirements Generation GWhs

The generation mix (GWhs) changes as a result of accelerated nuclear retirements demonstrate similar trends in both models. The generation mix under the Accelerated Nuclear Retirements Case under the CPP is shown in Figure 7-3. In addition, the figure also shows the difference between the CPP Base Cases to highlight the changes as a result of the higher nuclear retirement assumption. The results between both the IPM and AURORAxmp models show similar trends of generation (GWhs) as a result of the accelerated nuclear retirement case. The slightly lower overall generation numbers (TWh) in the High Renewable Penetration Case are made up through increased imports from Canada.

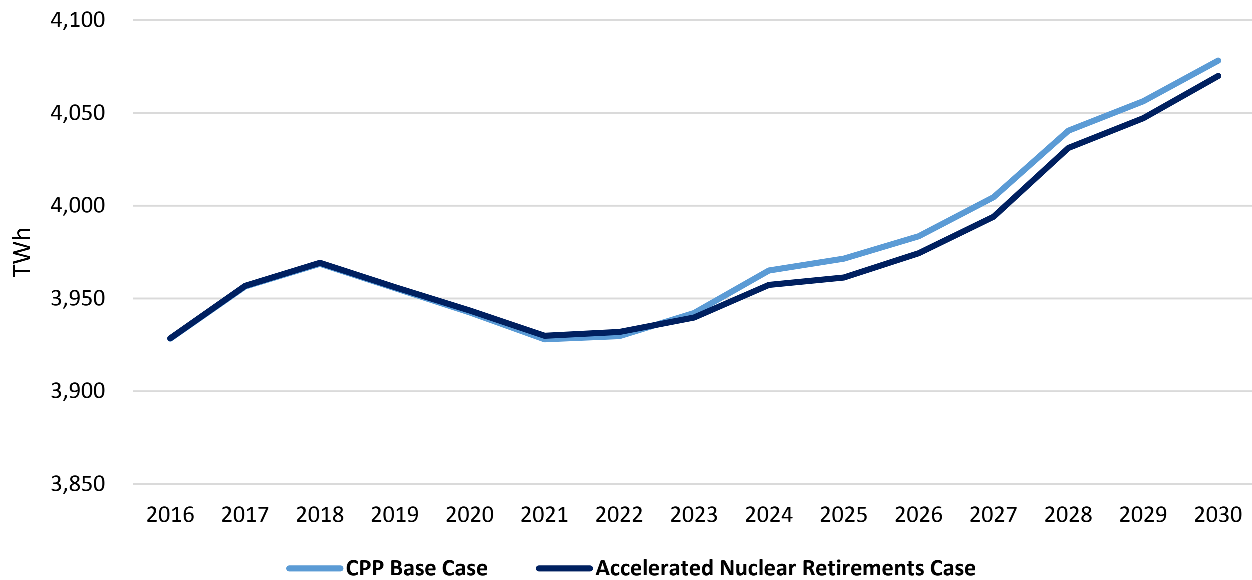

Figure 7-3: Generation under Accelerated Nuclear Retirement Case with Changes from CPP Base Case, AURORAxmp Model

Coal

Although there is more coal-fired capacity online in the high nuclear retirement case, the additional coal capacity runs at a lower capacity factor to meet the mass-based limitations. While the aggregate coal generation shows only a modest change, the differences are more pronounced on a regional basis. MISO-Central sees a large decrease in coal generation (GWhs) from the high nuclear retirement case that is offset by coal generation gains in PJM and SPP. Figure 7-4 shows the change in generation in major areas between the CPP Base Case and the Accelerated Nuclear Retirements Case.

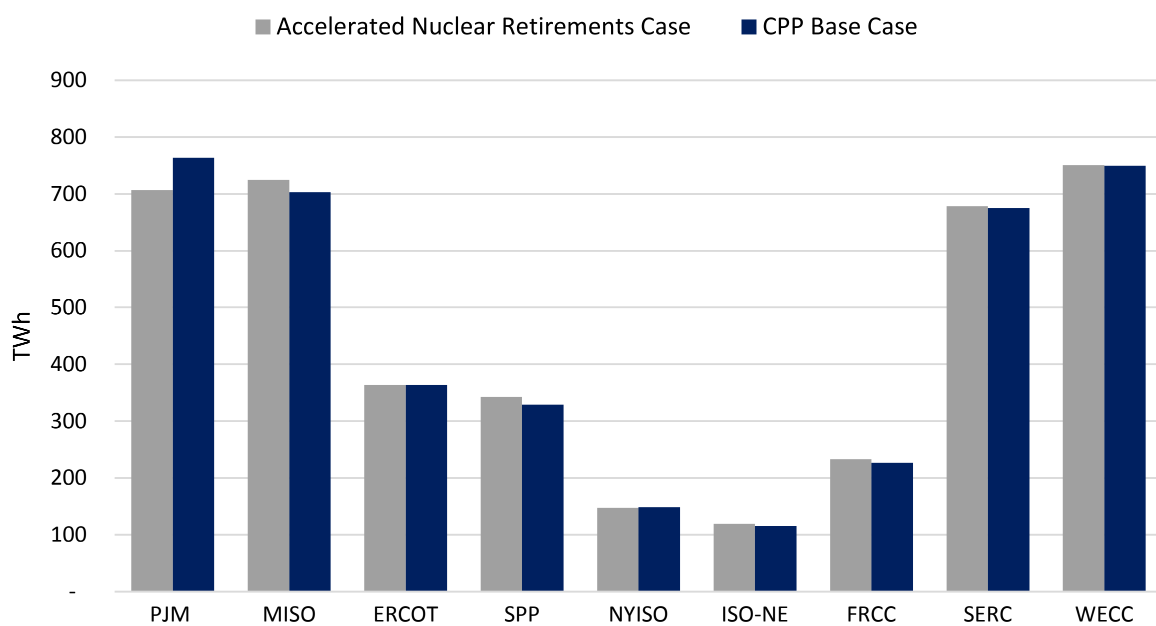

Figure 7-4: Generation CPP Base Case and CPP Accelerated Retirements Case, AURORAxmp Model

Natural Gas

Natural gas increases by 186 TWh by 2030 and accounts for the bulk of the lost nuclear generation. This pickup in NGCC generation to replace lost nuclear generation is most notable in MISO and PJM but is also found in the other areas with large losses in nuclear generation. Since most of this increased generation is from new NGCC capacity (not from existing CPP regulated NGCC units), their emissions do not need to be offset under the CPP.

Nuclear

In the high nuclear retirement cases nuclear generation declines by 172 TWh in 2025 and 249 TWhs in 2030 compared to the CPP Base Case. This decline in generation is a result from the accelerated retirements of nuclear units as input into the assumptions in this case.

Renewables

The greater nuclear retirements have little effect on solar PV (1 TWh increase by 2030) and only a modest effect (47 TWh increase in 2030) for wind. One reason for this limited impact is that wind is not a baseload resource and receives only a fraction of the capacity credit for reserve margin requirements. The wind increase is highly concentrated in MISO and SPP, where wind can more effectively compete.

Figure 7-5 shows the generation (GWhs) in the accelerated nuclear retirement cases versus the CPP Base Case.

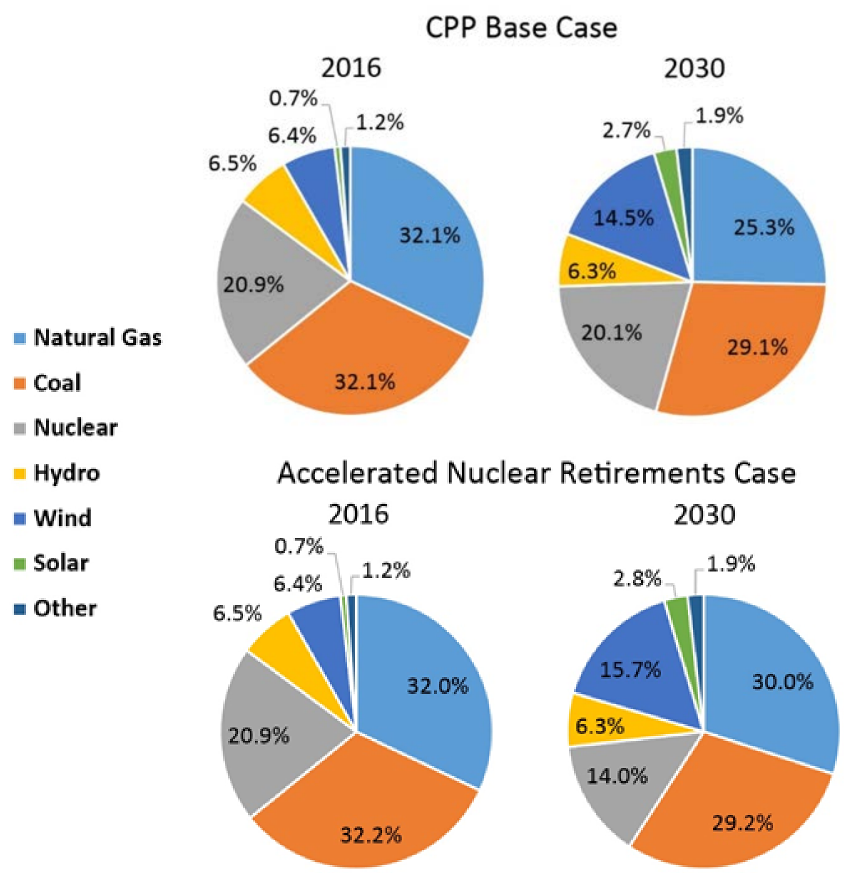

Figure 7-5: Percent Generation Mix, AURORAxmp Model

Reliability Issues

As more nuclear retirements are foreseen in the future due to the potential to become uneconomic other resources will need to fill the void. In the Accelerated Nuclear Retirements Case, various assumptions were incorporated to achieve an additional 31 GWs of nuclear retirements by 2030. Most of the shortfall as a result of nuclear retirements occurs in the later years of the analysis. This shortfall is filled with natural-gas-fired generation and renewables. With the large increase in renewables already projected in the other cases, reliance on additional renewables introduces more uncertainty around accommodating for ERSs. System planners should be aware of the potential that a displacement of nuclear could result in the need for incremental renewable resources as well as natural gas and should be planning accordingly to ensure BPS reliability. Given the large capacity losses when a nuclear unit retires, it will be essential that nuclear unit retirements are known far enough in advance to allow replacement capacity to be planned, permitted, financed, and brought online. With an increase in natural gas prices, nuclear generation becomes more economic, indicating a lower likelihood of this case. Additionally, some states have proposed state regulatory measures that would provide incentives for nuclear generation to remain operational even in the event that they become economically unviable. These potential measures could help states with their CPP compliance as well as provide the BPS with needed inertia for system stability.

Chapter 8: Reliability Risks

The results of the CPP analysis underscore significant changes occurring on the BPS both as a matter of the course of business as well as a direct effect of CPP implementation. The results of the IPM and AURORAxmp models have been delineated in the preceding chapters along with an overview of the key assumptions that went into deriving the aforementioned results. A deviation from the relevant input assumptions can introduce additional BPS risks. Additionally, the outputs themselves pose potential reliability challenges. These reliability challenges are discussed in more detail below.

Essential Reliability Services Risks

The CPP will accelerate wind and on-grid solar development that will escalate the need for ERSs, particularly in MISO and SPP. These critical services will take time and greater investment to develop. If these services are unable to keep up with the renewable growth, grid reliability can become increasingly challenged, particularly given that the renewable market share exceeds 30 percent of all generation in multiple power pools.

The North American BPS is undergoing a fundamental shift to a resource mix that relies less on conventional generation resources such as coal, nuclear, etc., to more asynchronous, distributed and storage-enabled resources such as wind, solar, and storage. In addition, the modern grid system will change in future to incorporate micrograds, smart networks, and other advancing technologies. NERC formed the Essential Reliability Services Task Force (ERSTF) that studied the implications to planning and operating the BPS in the face of these changing resource mix. Essential Reliability Services (ERSs) include three important building blocks of reliability, namely; frequency support, ramping, and voltage. In order to maintain the reliability of electric grid, resources need to be able to provide frequency support, voltage control, and ramping capability.

The ERSTF evaluated the capabilities of newer resources in terms of providing ERSs to see if they are able to provide them. ERSs will be needed for future as we transition from conventional generation mix to newer resource mix.

Based on the analysis of geographic areas that are experiencing the greatest level of change in their types of resources, a number of measures and industry practices are recommended to identify trends and prepare for the transition in resource mix.

Frequency[20]

The electric grid is designed to operate at a frequency of 60 hertz. Deviations from 60 Hz can have destructive effects on generators, motors, and equipment of all sizes and types. It is critical to maintain and restore frequency after a disturbance such as the loss of generation. An instantaneous (inertial) response from some resources and a fast response from other resources help to slow the rate of frequency drop during the arresting period by providing a fast increase in power output during the rebound period to stabilize the frequency.

Ramping[21]

Adequate ramping capability (the ability to match load and generation at all times) is necessary to maintain system frequency. Changes to the generation mix or the system operator's ability to adjust resource output can impact the ability of the operator to keep the system in balance.

[20] https://vimeopro.com/nerclearning/erstf-1/video/146105419

[21] https://vimeopro.com/nerclearning/erstf-1/video/140180921

Voltage[22]
Voltage must be controlled to protect system reliability and move power where it is needed in both normal operations and following a disturbance. Voltage issues tend to be local in nature, such as in sub-areas of the transmission and distribution systems. Reactive power is needed to keep electricity flowing and maintain necessary voltage levels.

Each reliability building block has an associated video animation to explain the concept of that particular ERS. Please click on each title above to access the corresponding video. Additionally, they are all available here:

The Basics of Essential Reliability Services[23]
NERC determined the ERSTF work to be ground breaking and accommodating to newer technologies to be integrated in the BPS. Thus, there is a further need to evaluate the ERS measures and identify their sufficient levels for various geographic areas. ERSTF will continue its work as Essential Reliability Services Working Group (ERSWG) to further analyze these measures. In addition, the ERSWG in a separate effort will evaluate the impact of distributed energy resources on the BPS.

Replacement Capacity Risk
This report discusses the level of retirements for coal resources as well as the need to replace that capacity with new resources, primarily natural gas and renewables in order to meet electricity demand. Replacement capacity may take years to plan, permit, finance, and build. The assessment produces the results indicating the level of resources that need to be built in order to meet demand; however, system planners must adequately plan for new resources to ensure that they can be built in a timely fashion to accommodate retirements and additional demand growth. Given that it takes up to five years or more to bring new natural gas-fired generation online, the program compliance timelines are already very tight. If the large block of accelerated unit retirements projected by the IPM model occur as early as this year, some reliability margin requirements could be missed if there are an insufficient number of replacement capacity projects planned or projects are delayed. Without replacement capacity, systems may be left with the choice of continuing to operate their higher-emitting coal-fired capacity and exceed state caps or operate systems below their reserve margin requirements.

Program Schedule Risk
In addition to the necessary planning for resource adequacy, uncertainty exists around program scheduling. Timing considerations must be accounted for in regards to program development and receiving all necessary authorizations throughout the regulatory process. That process would include time for public comment as well as receipt of EPA approval and the necessary time to implement appropriate compliance strategies. The 2022 implementation date could be a challenge for states that need to pass authorizing state legislation to develop the needed program framework and enforcement policies required to gain approval of their state implementation programs. In addition, the states need to develop state implementation plans, gain EPA approval, and provide sufficient time for the affected sources to plan, permit, finance, and build replacement capacity, transmission, and any needed upstream infrastructure (e.g., natural gas pipelines). With the CPP being litigated, it is uncertain what the final rule deadlines will be and when all states can complete this process.

Demand Risk
The NERC assessment used existing demand projections from EPRI[24] in the Reference Case. The high case for energy efficiency as developed by EPRI was used for the CPP Base Case and remaining sensitivities. Large changes

[22] https://vimeopro.com/nerclearning/erstf-1/video/132358336

[23] https://vimeopro.com/nerclearning/erstf-1

[24] http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001022196

in electricity demand could have implications on early compliance measures, thereby having an incremental and compounded effect on later-year compliance strategies as well.

Supply Risk

A loss of zero-emission or low emitting capacity in heavy concentrations could have a material effect on compliance capabilities. Large levels of nuclear retirements, natural gas retirements, or impediments to renewable resources could have significant effects on compliance strategies.

Trading Risk

The assessment assumes optimal trading with optimal interstate trading in the National Trading Case and optimal intrastate trading in the remaining CPP cases. In the intrastate cases if companies keep large allowance supplies off the market, this could create issues for coal heavy companies unable to find a market to counterbalance their emissions. Similarly, in the National Trading Case, the models assume full interstate trading to be optimized; however, some states may decide to keep allowances off the market, impeding trading as a compliance strategy.

Transmission Risk/Renewable Risk

The ability to absorb large amounts of variable renewable generation will require additional transmission and ancillary services to support expansion. New transmission projects will need the requisite time for planning, permitting, and construction, which can take many years to complete. Retirements and additions must be balanced to ensure that the requisite transmission can be built to accommodate the large shift in resources projected in the assessment.

Energy Efficiency Risk

The CPP could create a performance risk in terms of forecasted reductions as a result of energy efficiency materializing. CPP compliance is heavily dependent upon enhanced energy efficiency measures to reduce coal-fired generation. In addition, changes in economic growth and adverse weather could have significant impacts on demand. In both cases, the power load and system emissions could be greater than projected. If these conditions were to develop, the power industry would need to pursue increasingly higher cost emission reduction options beyond those projection in these analysis. These additional compliance measures will likely be dominated by building additional natural gas combined-cycle capacity. Renewables would play a much smaller role because much of the renewables that are being built are reaching caps in many areas in regards to maximum build levels in a year (as seen in historical analyses),[25] and as a result, additional decreases in emissions would most likely come from an increase in natural gas builds. It is important for planners to consider this dynamic when developing plans in order to be cognizant of the necessary lead times for natural gas infrastructure.

Figures 8-1 through 8-4 shows the associated resource implications under both the IPM and AURORAxmp models between 2016 and 2030.

[25] Nextera Energy

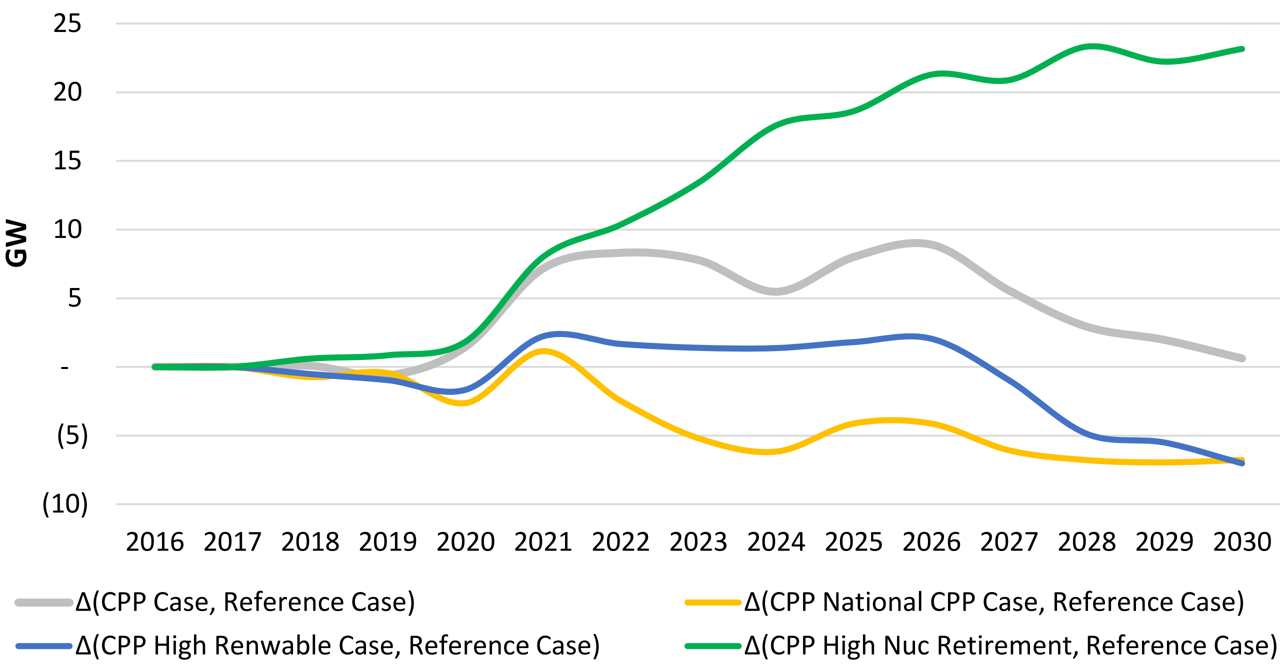

Figure 8-1: Change in Natural Gas Capacity (GWs), AURORAxmp Model

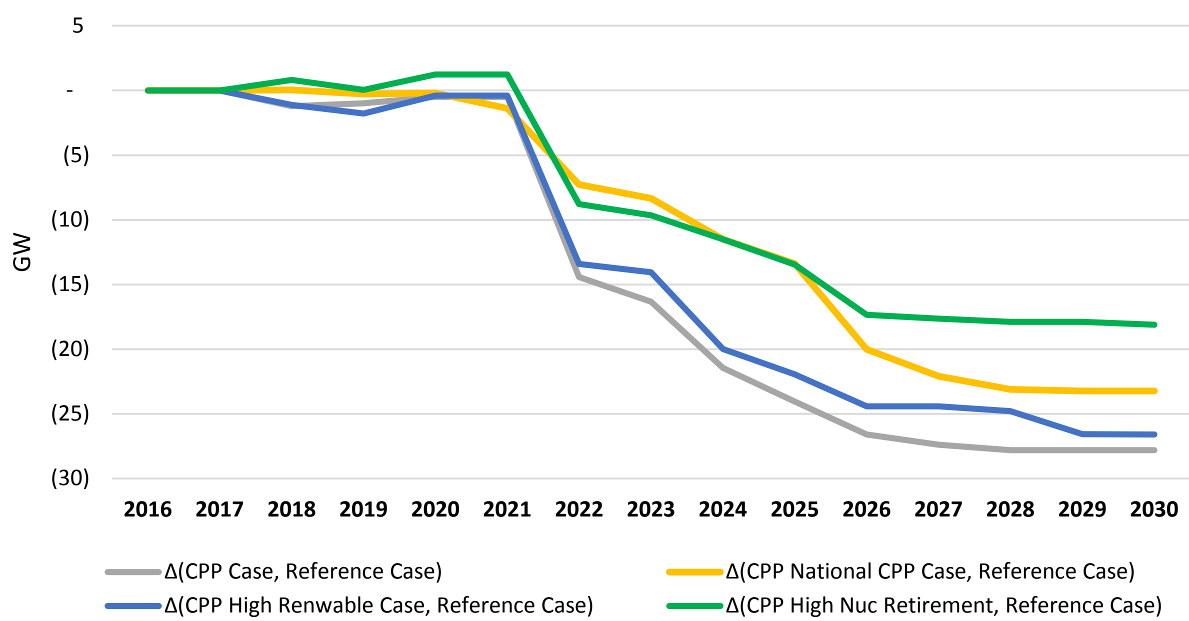

Figure 8-2: Change in Coal Capacity (GWs) , AURORAxmp Model

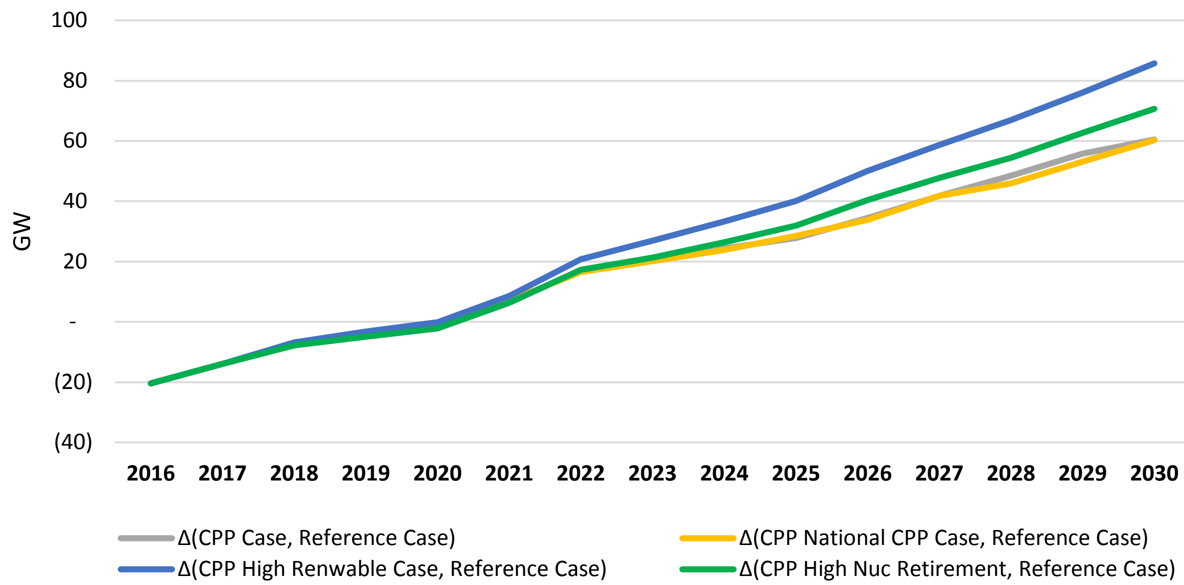

Figure 8-3: Change in Wind Capacity (GWs) , AURORAxmp Model

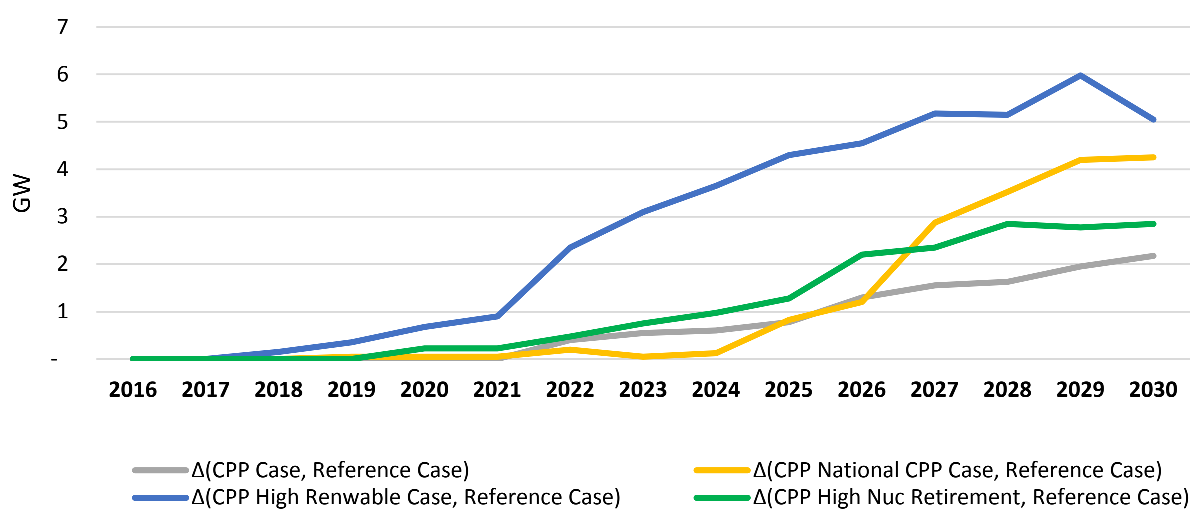

Figure 8-4: Change in Solar Capacity (GWs) , AURORAxmp Model

Chapter 9: Conclusion

This report represents NERC's continuing efforts to report on reliability issues associated with the EPA's CPP final rule. Although an element of uncertainty has been introduced due to the Supreme Court stay of the final rule, many of the resource changes highlighted in this report are occurring regardless of the CPP. If the final rule is upheld, these changes will potentially be accelerated as outlined in this report. It is NERC's intention that this document be used as a platform by industry stakeholders to continue to develop more granular and localized studies to assess reliability impacts. NERC will continue to assess CPP-related reliability issues as resource and transmission modifications are introduced to the BPS. This will be accommodated within NERC's annual Long Term Reliability Assessment (LTRA).

Recommendations

1. ISOs/RTOs, utilities, asset owners/operators, and planning coordinators should continue to conduct detailed system evaluations to identify areas of reliability concern and work in partnership with states, Regions, and policy makers to provide clear guidance in regards to the necessary planning activities that must transpire in order to ensure BPS reliability. System evaluations should use the NERC CPP Phase II study as a basis for more granular and localized studies to plan for compliance and ensure system reliability.
2. The CPP final rule stipulates that state submittals must demonstrate that reliability has been evaluated and ensured. NERC advises planners to review and incorporate recommendations from *Reliability Considerations for Clean Power Plan Development* [26] into their state plans. Particularly state plans should take the following into consideration to ensure reliability:
    - Utility commissions and state environmental offices should ensure that sufficient levels of ERSs are planned and included in resource plans as large levels of asynchronous generation are incorporated into the BPS.
    - Utility commissions and state environmental offices must also take into account timing considerations around the development of new resources and the necessary upstream infrastructure.
    - State plan submittals must retain adequate reserve margin levels.
    - Planners must consider the changing operating characteristics of resources and incorporate those changes into their resource planning processes.
    - State and utility planners must also account for changes to, and the feasibility of, regional imports and exports as a result of interregional changes in power flows to meet their obligations as a result of the CPP.
    - State Planners must adequately assess how much of their required emissions reductions can be met through trading of emissions allowances or emission reduction credits and plan accordingly.
3. NERC should continue to update and expand its assessments of the reliability implications of the CPP and provide independent evaluations to stakeholders, states, regulators, and policy makers. Additionally, NERC should work with the NERC Regions as they leverage the model results in this analysis to conduct their own regional analyses. NERC should incorporate changes in resource and transmission adequacy into its LTRA on an ongoing basis each year as system changes are planned that incorporate CPP impacts. Additionally, NERC should incorporate probabilistic methods into its LTRA to adequately assess risks both probabilistically and deterministically.

[26] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Reliability%20Considerations%20for%20State%20CPP%20Plan%20Development%20Baseline%20Final.pdf

4. The U.S. Environmental Protection Agency (EPA), the U.S. Department of Energy (DOE), and the Federal Energy Regulatory Commission (FERC) entered into a Memorandum of Understanding whereby they agreed that working together the three agencies will make reasonable efforts to: (1) monitor the progress of states as they develop single-state or multi-state plans to meet the requirements of the CPP; (2) monitor the implementation of state plans or, where applicable, a federal plan, to maintain awareness of any potential electric reliability effects; and (3) ensure coordination, as appropriate, to address any issues concerning reliability that may arise. [27] The memorandum further stipulates that the agencies will engage with stakeholders including utility trade associations, organizations of state agencies, ISOs/RTOs, NERC, and additional entities that participate in reliability planning and execution. These agencies should continue to work together in conjunction with the aforementioned stakeholders to ensure that as state plans are being developed that reliability has been ensured throughout the process and that final state plan submittals have addressed and resolved any reliability issues as a result of CPP compliance.
5. NERC should continue its work around sufficiency guidelines for ERS as well as its formulation of a task force to evaluate distributed energy resources on the distribution system that may have an effect on BPS reliability. These efforts should be aligned with FERC efforts on primary frequency response as delineated in FERC's recent Notice of Inquiry in Docket No. R16-6-000[28]; *FERC's NOPR on Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities in RM16-8-000; and FERC's NOPR on Reactive Power Requirements for Non-Synchronous Generation in Docket No. RM16-1-000*[29]

[27] https://www.ferc.gov/media/headlines/2015/CPP-EPA-DOE-FERC.pdf
[28] https://www.ferc.gov/whats-new/comm-meet/2016/021816/E-2.pdf
[29] https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-3.pdf

Appendix

The supporting input assumptions for the IPM and AURORAxmp analysis can be found at http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

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Questions

Please direct all inquiries to NERC staff (assessments@nerc.net). References to the data and/or findings of the assessment are welcome with appropriate attribution of the source to the NERC *Reliability Considerations for Clean Power Plan Development*. However, extensive reproduction of tables and/or charts will require permission from NERC staff.

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