Edison Electric Institute

Potential Impacts of Environmental Regulation on the U.S. Generation Fleet

Final Report

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EXECUTIVE SUMMARY

Introduction

This report represents a collaborative effort by the Edison Electric Institute (EEI) and its members to model a variety of prospective EPA rules for air quality, coal combustion residuals, cooling water intakes, and greenhouse gases. Understanding the combined effect that pending regulations for air quality, coal combustion residuals, cooling water intake structures, and greenhouse gases will have on the electric industry is a crucial issue for EEI and its members.

EEI utilized ICF International (ICF) and its proprietary Integrated Planning Model (IPM®) for this work. ICF provided modeling guidance to EEI, helping to identify specific data needs, modeling inputs and run structures, and ran the IPM® model. However, EEI had final responsibility for the selection and approval of all input assumptions and for determining the parameters of the modeling runs that were completed for this study. IPM® is a multi-region model that endogenously determines capacity expansion plans, unit dispatch and compliance decisions, as well as power, coal and allowance price forecasts, all of which are based on power market fundamentals. IPM® is the same platform used by Environmental Protection Agency's (EPA's) Clean Air Markets Division for analyzing air policy scenarios. Chapter 2 contains additional information on the structure and operation of IPM®.

This report summarizes the potential impacts for unit retirements, capacity additions, pollution control installations, and capital expenditures – all direct outputs from IPM®. Areas not analyzed in this report include: potential impacts to retail or wholesale electricity prices; potential impacts to local economies or potential job losses associated with plant closures; and potential local or regional impacts to grid reliability from unit retrofits and retirements. While these are all important potential impacts, assessing them is best done by individual companies and/or local Regional Transmission Organizations (RTOs), which are better suited to analyze local impacts using more refined modeling inputs than are possible when utilizing average cost factors employed by EEI for the national-scale modeling discussed in this report.

The modeling inputs are based on national-level average values selected by EEI and may not be reflective of the specific costs, constraints or operational experience of individual companies, all of which will vary based on company-specific circumstances. Thus, while the report address potential national- and regional-scale outcomes, the impacts to individual companies may vary significantly. EEI recognizes that a variety of outcomes are possible depending upon which policy, market and technology variables apply, and our member companies may have different views as to which of these variables are most likely to apply in the future.

In selecting assumptions, EEI made every effort to utilize the same input assumptions utilized by EPA. Where EEI believed a set of assumptions utilized by EPA was not reflective of current utility costs or operational experience, EEI chose alternate assumptions. For those areas for which EPA has not yet published modeling assumptions, assumptions were developed by EEI. All assumptions utilized in the modeling have been documented for full transparency and are included in Appendix A.

Scenarios Modeled

In addition to a Reference Case, EEI modeled seven combinations of alternate regulatory scenarios to test the response of the electricity generation system to a variety of potential regulatory outcomes and two natural gas price sensitivities. For example, for the alternate regulatory policies, EEI set parameters for two air policy cases. In the Base Air Case, EEI assumed promulgation of the Transport Rule consistent with the preferred option proposed by EPA in that rulemaking, but eventually requiring selective catalytic reduction (SCR) on units in the region by 2018. EEI also assumed promulgation of a hazardous air pollutants (HAPs) Maximum Achievable Control Technology (MACT) rule that was sufficiently stringent to trigger the need for scrubbers, activated carbon injection (ACI) and a baghouse/fabric filter on all coal units across the United States. In the Alternate Air Case, EEI modeled a version of the Transport Rule that provided continued trading flexibility for NO_X, although at a lower cap level, and allowed HAPs MACT compliance to be met on units less than 200 megawatts (MW) through the use of dry sorbent injection (DSI).

In a similar fashion, EEI created both base and alternate regulatory scenarios for water, coal ash and carbon dioxide (CO_2) by applying different regulatory requirements that bracket a range of possible regulatory outcomes.

A high-level summary of the 10 modeling runs is shown below:

Run	Scenario	Description
1	Reference Case	CAIR + State Regulations
2	Scenario 1	Base Air Case + Ash (Subtitle D) + Water
3	Scenario 1 + Alt Air	<u>Alt Air Case</u> + Ash (Subtitle D) + Water
4	Scenario 1 + Alt Water	Air Base Case + Ash (Subtitle D) + <u>Alt Water</u>
5	Scenario 2	Air Base Case + Ash (Subtitle D) + Water + <u>CO_2</u>
6	Scenario 2 + Alt CO2	Air Base Case + Ash (Subtitle D) + Water + <u>Alt CO_2</u>
7	Scenario 2 + Alt Air	<u>Alt Air Case</u> + Ash (Subtitle D) + Water + CO_2
8	Scenario 2 + Alt Ash	Air Base Case + <u>Alt Ash (Subtitle C)</u> + Water + CO_2
9	Scenario 2 + $1.50 gas	Air Base Case + Ash (Subtitle D) + Water + CO_2 + <u>$1.50 gas</u>
10	Scenario 2 + $3.00 gas	Air Base Case + Ash (Subtitle D) + Water + CO_2 + <u>$3.00 gas</u>

Additional information on the scenarios described above can be found in Chapter 1 and Appendix B.

National-Level Results Summary

An overview of the high-level results of the EEI modeling analysis conducted by ICF is shown in the four tables that follow. The tables summarize the Retirements of coal capacity due to the modeled regulations; the New Builds that are built to replace the retired capacity, as well as to meet load growth; the Retrofits that need to be installed on those coal plants that invest in environmental controls and continue to run; and the Capital Expenditures (capex) associated with both the new builds and the retrofits. The results presented below are at the national level and are for the coal units only. In addition to the national-level results contained in the tables that follow, Chapter 3 and Appendix C contain data for each of the categories on a regional level. Chapter 3 also provides a complete analysis of the results from each of the summary tables and discusses the key drivers that have led to a particular outcome.

National Coal Retirements (GW)

Run	Scenario	Planned Coal Retirements	Unplanned Coal Retirements		Total Coal Retirements		Incremental Coal Retirements	
		2015	2015	2020	2015	2020	2015	2020
1	Reference Case	6	16	19	22	25	0	0
2	Scenario 1	6	50	50	56	56	34	31
3	Scenario 1 + Alt Air	6	41	41	46	46	24	21
4	Scenario 1 + Alt Water	6	49	50	55	55	33	30
5	Scenario 2	6	73	90	79	95	57	71
6	Scenario 2 + Alt CO2	6	66	73	71	79	50	54
7	Scenario 2 + Alt Air	6	64	77	70	82	48	58
8	Scenario 2 + Alt Ash	6	75	96	81	101	59	76
9	Scenario 2 + $1.50 Gas	6	47	56	52	61	31	37
10	Scenario 2 + $3.00 Gas	6	33	36	38	41	17	17

Note that Total and Incremental numbers may not sum due to rounding.

Where:

- Planned Coal Retirements – represents those retirements announced by companies that are considered "firm" enough to be hardwired into the model. The planned coal retirements are consistent throughout all scenarios at 6 gigawatts (GW). It should be noted that these retirements represent those units that have announced firm retirements based on regulatory filings, press releases and EEI member company feedback. Due to the timing of this analysis, there have been subsequent announcements that are not captured in this list.
- Unplanned Coal Retirements – represents those retirements that are economic based on the modeling and the retirement logic as described Chapters 2 and 3. The cumulative retirements are shown for two representative years, 2015 and 2020.
- Total Coal Retirements – sums the planned and unplanned coal retirements. The total number presents the total amount of coal capacity forecast under each scenario to be retired from the existing coal fleet.
- Incremental Coal Retirements – represents those retirements that are incremental to the retirements seen in the Reference Case. The incremental retirements present a picture of the direct impact of the Scenarios on coal retirements.

National Capacity Additions (GW)

Run	Scenario	Planned Additions	Unplanned Additions		Total Additions		Incremental Additions	
		2015	2015	2020	2015	2020	2015	2020
1	Reference Case	35	30	48	66	89	0	0
2	Scenario 1	35	48	91	84	132	18	43
3	Scenario 1 + Alt Air	35	37	79	73	120	7	31
4	Scenario 1 + Alt Water	35	45	83	80	124	14	35
5	Scenario 2	35	77	125	112	165	46	76
6	Scenario 2 + Alt CO2	35	61	94	96	135	30	46
7	Scenario 2 + Alt Air	35	65	110	100	151	35	62
8	Scenario 2 + Alt Ash	35	77	129	113	170	47	81
9	Scenario 2 + $1.50 Gas	35	64	106	99	147	33	58

Note that Total and Incremental numbers may not sum due to rounding. The builds are a national-level aggregation across all capacity types, including natural gas, renewables, and nuclear.

Where:

The detailed results by capacity type are presented in charts in Appendix C of this document. The summary table above is constructed in a similar manner to the national-level retirement table presented in the previous section with the following categories:

- Planned Additions – represents those additions that have been announced by companies and are considered "firm" enough to be hardwired into the model. The planned additions are consistent throughout all scenarios at 35 GW. It should be noted that the builds represent those units that either are "under construction" or meet two of the three following criteria:
    - Fully permitted
    - Signed a purchased power agreement (PPA)
    - Financed

  Given the fact that the three criteria can be difficult to find publicly, the most common reason for inclusion is "under construction" status. Due to the timing of this analysis, there may have been subsequent announcements that are not captured in this list.
- Unplanned Additions – represents those builds that are economic based on the modeling and the build logic as described in Chapters 2 and 3. The cumulative builds are shown for two representative years, 2015 and 2020.
- Total Builds – sums the planned and unplanned builds. The total number presents the total amount of capacity forecast to be built by 2015 and 2020 to meet load in light of the retirements occurring in that scenario.
- Incremental Builds – represents those builds that are incremental to the builds seen in the Reference Case. The incremental builds present a picture of the impact of the Scenarios on builds.

National Pollution Control Installations (GW)

Run	Scenario	Planned Retrofits	Unplanned Coal Retrofits		Total Coal Retrofits		Incremental Coal Retrofits	
		2015	2015	2020	2015	2020	2015	2020
1	Reference Case	81	26	47	107	127	0	0
2	Scenario 1	81	286	611	367	691	260	564
3	Scenario 1 + Alt Air	81	306	565	386	646	280	518
4	Scenario 1 + Alt Water	81	289	532	369	613	263	486
5	Scenario 2	81	244	504	325	584	218	457
6	Scenario 2 + Alt CO2	81	259	542	339	622	233	495
7	Scenario 2 + Alt Air	81	264	479	345	560	238	432
8	Scenario 2 + Alt Ash	81	241	588	322	669	215	542
9	Scenario 2 + $1.50 Gas	81	287	611	368	691	261	564
10	Scenario 2 + $3.00 Gas	81	312	677	392	757	286	630

Note that Total and Incremental numbers may not sum due to rounding.

Where:

The results in the table above represent GW of cumulative retrofit installations. For example, a 1-GW unit that required both a scrubber and an SCR would appear in the table above as 2 GW of retrofits.

- Planned Coal Retrofits – represents those retrofits announced by companies and are considered "firm" enough to be hardwired into the model. The planned coal retrofits are consistent throughout all scenarios at 81 GW. It should be noted that these retrofits represent controls on units that have announced firm retrofits based on regulatory filings, press releases and EEI member company feedback. Due to the timing of this analysis, there have been subsequent announcements that are not captured in this list.
- Unplanned Coal Retrofits – represents those retrofits that are economic based on the modeling and the retrofit logic as described in Chapters 2 and 3. The cumulative retrofits are shown for two representative years, 2015 and 2020.
- Total Coal Retrofits – sums the planned and unplanned coal retrofits. The total number presents the total amount of environmental retrofit installations installed on the coal fleet through 2015 and 2020.
- Incremental Coal Retrofits – represents those retrofits that are incremental to the retrofits seen in the Reference Case. The incremental retrofits present a picture of the impact of the Scenarios on coal retrofits.

Cumulative CAPEX for Retrofits and New Builds (Billion 2008$)

Run	Scenario	Retrofits		New Builds		Total		Incremental Total	
		2015	2020	2015	2020	2015	2020	2015	2020
1	Reference Case	36	43	146	211	182	254	0	0
2	Scenario 1	96	170	171	258	267	429	85	175
3	Scenario 1 + Alt Air	107	150	158	245	264	395	83	141
4	Scenario 1 + Alt Water	97	159	167	250	264	409	82	155
5	Scenario 2	85	148	210	313	295	461	113	206
6	Scenario 2 + Alt CO2	88	151	188	267	276	418	94	164
7	Scenario 2 + Alt Air	92	133	195	296	287	429	105	175
8	Scenario 2 + Alt Ash	84	182	212	319	296	501	114	247
9	Scenario 2 + $1.50 Gas	97	177	202	308	299	485	117	231
10	Scenario 2 + $3.00 Gas	104	196	206	329	310	525	129	270

Note that Total and Incremental numbers may not sum due to rounding. All expenditures are in real 2008 billion of $.

Where:

- Coal unit retrofits – represents cumulative overnight capital costs plus allowance for funds used during construction (AFUDC)/interest capitalized during construction (IDC) through 2015 and 2020.
- New capacity builds – represents cumulative overnight capital costs plus AFUDC/IDC through 2015 and 2020.
- Total Capex – sums the capital expenditure on coal unit retrofits and new capacity builds.
- Incremental Total Capex – represents the increase in capex for builds and retrofits relative to the Reference Case.

Chapter 1: INTRODUCTION

This modeling effort was undertaken for the education of the Edison Electric Institute (EEI) and its member companies as to the possible effects of a variety of prospective EPA rules under a variety of potential future scenarios.

It represents a collaborative effort to synthesize alternative approaches suggested by EEI's membership for the selection of the modeling inputs (such as expected natural gas prices and the costs for new technology, etc.); scenarios about the potential regulations themselves (*i.e.*, what regulations will apply, and the timing and stringency of those regulations); and sensitivities (*i.e.*, variations in gas prices, technology choices and regulatory requirements) for the analysis.

The modeling inputs are based on national-level average values and may not be reflective of the specific costs, constraints or operational experience of individual EEI member companies, all of which will vary based on company-specific circumstances. Thus, while the report address potential national and regional-scale outcomes, the impacts to individual companies may vary significantly.

EEI recognizes that a variety of outcomes are possible depending upon which policy, market and technology variables apply, and our member companies may have different views as to which of these variables are most likely to apply in the future.

1.1 Purpose of the Study

At the time this study was launched, there was recognition by EEI member companies that the interaction among rules for air quality, cooling water intakes, coal ash handling, and greenhouse gases (GHGs) created a complex analytical challenge, and that looking at the impacts of the rules simultaneously provided for a different result than when the rules were analyzed in isolation. While work was being performed by individual companies to determine the impact to company generation fleets from the multiple rulemakings, there was not a comprehensive national-level study that looked at the impacts to the entire U.S. electricity generation fleet as a whole.

EEI members recognized that such a study would be beneficial to help understand the potential magnitude of impacts to the industry at the national and regional levels.

1.2 How the Study Was Managed

This work was guided by technical and policy experts from 31 EEI member companies. These companies, informally known as the Generation Fleet Modeling Work Group (Work Group), represented a broad cross-section of EEI's membership – utilizing diverse fuel mixes and with wide geographic representation.

While this level of participation created some degree of complexity, that complexity is also a testament to the strength of the final outcome – one that represents a wide range of views and a set of modeling runs that brackets the most likely set of possible outcomes.

ICF International (ICF) provided modeling guidance to the Work Group, helping to identify specific data needs, modeling inputs and run structures, and then conducted the analysis using the Integrated Planning Model (IPM®). However, the Work Group had final responsibility for the selection and approval of all input assumptions, and for determining the parameters of each of the 10 modeling runs that were completed for this study.

1.3 Limitations of the Study

The results reported in Chapter 3 are direct outputs from the IPM® model. No attempt has been made in this report to analyze aspects beyond these direct model outputs. Areas not analyzed in this report include: potential impacts to retail or wholesale electricity prices; potential impacts to local economies or potential job losses associated with plant closures; and potential local or regional impacts to grid reliability from unit retrofits and retirements. While these are all important aspects of the proposed rules, assessing these types of potential impacts is best done by individual companies and/or local Regional Transmission Organizations (RTOs), which are better suited to analyze local impacts using more refined modeling inputs than are possible when utilizing average cost factors employed by EEI for the national-scale modeling discussed in this report.

1.4 Assumptions Used in the Modeling

In selecting assumptions, the Work Group made every effort to utilize the same input assumptions utilized by EPA's Clean Air Markets Division as documented in its IPM® Base Case v.4.10. Where the Work Group believed a set of assumptions utilized by EPA was not reflective of current utility costs or operational experience, the Work Group chose alternate assumptions. For those areas for which EPA has not yet published modeling assumptions, such as cooling tower costs and coal ash handling conversion, assumptions were developed by the Work Group. Table 1.1 provides a high-level summary showing the source of major assumptions utilized in the modeling.

All assumptions utilized in the modeling effort have been documented for full transparency. Appendix A contains complete documentation of the assumptions utilized by EEI in its modeling effort.

Table 1.1: Source of Major Assumptions in Reference Case

Assumption	Source
Electric Demand – National Annual Avg.	EPA/AEO 2010*
Electric Demand – Regional	EPA/AEO 2010
Electric Demand Elasticity for CO_2 Scenarios	EPA CO_2 Analyses
Natural Gas Supply Curves (Henry Hub)	EPA IPM® 4.10
Coal Price Supply Curves and Coal Transportation Costs	EPA IPM® 4.10
Biomass Supply Curves	AEO2009
New Build Cost and Performance	EPA IPM® 4.10
Air Retrofit Cost and Performance	EPA IPM® 4.10/EVA
Water Retrofit Cost and Performance	EPRI
Ash Retrofit Cost and Performance	EOP/EPRI
Technology Limits	EPA/NEI
Financing Assumptions – New Builds	EPA IPM® 4.10
Financing Assumptions – Retrofits	EPA IPM® 4.10/EEI

* U.S. Energy Administration, Annual Energy Outlook 2010

1.5 Scenario and Sensitivity Run Descriptions

In addition to a Reference Case, EEI modeled seven combinations of alternate regulatory scenarios to test the response of the electricity generation system to a variety of potential regulatory outcomes and two natural gas price sensitivities.

For example, for the alternate regulatory policies, EEI set parameters for two air policy cases. In the Base Air Case, EEI assumed promulgation of a Transport Rule consistent with the preferred option proposed by EPA in that rulemaking, but eventually requiring selective catalytic reduction (SCR) on units in the region by 2018. EEI also assumed promulgation of a hazardous air pollutants (HAPs) Maximum Achievable Control Technology (MACT) rule that was sufficiently stringent to trigger the need for scrubbers, activated carbon injection (ACI) and a baghouse/fabric filter on all coal units across the United States. In the Alternate Air Case, EEI modeled a version of the Transport Rule that provided continued trading, although at a lower cap level, and allowed HAPs MACT compliance to be met on units less than 200-megawatt (MW) through the use of dry sorbent injection (DSI).

In a similar fashion, EEI created both base and alternate regulatory scenarios for water, ash and carbon dioxide (CO_2) by applying different regulatory requirements that bracket the range of possible regulatory outcomes.

A summary of the 10 modeling runs and a brief description of the underlying policy cases and assumptions employed in each run are shown in Table 1.2. Appendix B contains full supporting detail and documentation for each of the underlying policy cases.

Table 1.2: Summary of Scenario Descriptions

Run	Scenario	Description
1	Reference Case	**CAIR + State Regulations** All "on the books" state and federal regulations, including CAIR, WRAP and all state-based mercury regulation. Also includes all mandatory state-based RPS requirements.
2	Scenario 1	**Base Air Case + Ash (Subtitle D) + Water** • MACT compliance for all HAPs requires all coal units to be controlled with a scrubber (wet or dry), activated carbon injection (ACI) and a baghouse/fabric filter. Oil gas steam units that burn oil only have to install an electrostatic precipitator (ESP). Oil gas steam units that are dual fuel capable are assumed to switch to gas to comply. Compliance is required by 2015 to satisfy the HAPs MACT Consent Decree timeline. • No additional controls are required for SO_2-specific compliance. • Eastern NO_X compliance is modeled on EPA's preferred option for the proposed Transport Rule with trading allowed up to the variability limits through 2017. Starting in 2018 all units required to install SCRs to be deemed "well controlled" to meet future NO_X requirements. • Western NO_X compliance modeled to assume that for BART compliance that SCRs are installed on all units where the cost to control NO_X is $5,000/ton removed or less starting in 2018. Prior to 2018, only announced and committed SCRs as a result of completed BART determinations are required. • All units with wet fly ash disposal and/or wet bottom ash disposal are required to convert to dry handling, and install a landfill and wastewater treatment facility. Assume the final rule promulgation occurs in 2012. Under Subtitle D, plants will have 5 years (2017) to stop using active ponds and 7 years (2019) to close all ponds. • All fossil and nuclear facilities that have at least one once-through cooling unit are required to install cooling towers. Fossil units are allowed 10 years to achieve compliance. Nuclear units are allowed at least 15 years or to their current license expiration. To emulate this timeline, EEI has assumed compliance no later than 2022 for fossil units and no later than 2027 for nuclear units.
3	Scenario 1 + Alt Air	**<u>Alt Air Case</u> + Ash (Subtitle D) + Water** MACT compliance is similar to Base Air Case, but the requirement for a scrubber is relaxed to allow units 200 MW or less to install dry sorbent injection (DSI) technology if it is deemed to be the more economical solution. Eastern NO_X is adjusted to allow trading to continue, but cap is adjusted to approximate levels proposed under Sen. Carper's legislation. All other requirements are unchanged.

Table 1.2: Summary of Scenario Descriptions (continued)

Run	Scenario	Description
4	Scenario 1 + Alt Water	**Air Base Case + Ash (Subtitle D) + Alt Water** All fossil and nuclear facilities that have once-through cooling with a design intake flow rate of 125 million gallons per day or greater and withdraw water from sensitive water bodies (oceans, estuaries and tidal rivers) are required to install cooling towers. Fossil units are allowed 10 years to achieve compliance. Nuclear units are allowed at least 15 years or to their current license expiration. To emulate this timeline, EEI has assumed compliance no later than 2022 for fossil units and no later than 2027 for nuclear units. All other requirements are the same as Scenario 1.
5	Scenario 2	**Air Base Case + Ash (Subtitle D) + Water + CO_2** Same as Scenario 1 with a $25 CO_2 price added starting in 2017.
6	Scenario 2 + Alt CO2	**Air Base Case + Ash (Subtitle D) + Water + Alt CO_2** Scenario 2 with the CO_2 price starting at $10 (instead of $25) in 2017.
7	Scenario 2 + Alt Air	**Alt Air Case + Ash (Subtitle D) + Water + CO_2** Scenario 2 with Alternate Air policy (see Run #3 for description of Alt. Air policy).
8	Scenario 2 + Alt Ash	**Air Base Case + Alt Ash (Subtitle C) + Water + CO_2** Scenario 2 with Ash treated as hazardous under Subtitle C.
9	Scenario 2 + $1.50 gas	**Air Base Case + Ash (Subtitle D) + Water + CO_2 + $1.50 gas** Same as Scenario 2 with natural gas $1.50/mmBtu higher than in Scenario 2.
10	Scenario 2 + $3.00 gas	**Air Base Case + Ash (Subtitle D) + Water + CO_2 + $3.00 gas** Same as Scenario 2 with natural gas $3.00/mmBtu higher than in Scenario 2.

Chapter 2: MODELING PLATFORM

2.1 The Integrated Planning Model (IPM®)

IPM® is ICF's proprietary engineering/economic capacity expansion and production-costing model of the power sector supported by an extensive database of every boiler and generator in the nation. It is a multi-region model that endogenously determines capacity expansion plans, unit dispatch and compliance decisions, as well as power, coal and allowance price forecasts, all of which are based on power market fundamentals. IPM® explicitly models fuel markets, power plant costs and performance characteristics, environmental constraints (air, ash and water), and other power market fundamentals. The figure below illustrates the key inputs and outputs of IPM®.

ICF's Integrated Planning Model (IPM®)

2.2 IPM® Optimization Process

The North American version of IPM® is divided into a number of regions, depending on the focus of the analysis being performed, including Canadian provinces. Each of the regions must meet its assumed load and peak demand requirements through a combination of:

1. **Use of existing generation resources** – IPM® is based on an extensive database of every boiler and generator in the nation. Each unit is characterized by capacity type, capacity contribution to reserve, heat rate, operating characteristics, fixed and variable operating costs, fuel choices, and emission rates.
2. **Addition of new generation resources** – One of the distinguishing strengths of IPM® is that it endogenously determines optimal market entry for new generating capacity. The IPM dataset, compiled through a stakeholder process with EEI members, contains cost and performance assumptions for a wide variety of new generation capacity technologies, including fossil, nuclear and renewables.
3. **Use of transmission resources** – IPM® uses a zonal transportation approach to transmission, with regions connected by transmission links that are defined by capacity by season and hour type and by the cost to move power across the link. The total transfer capability (TTC) of each link is derived from load flow studies and other sources. Regional boundaries are typically determined in such a way as to represent real world bottlenecks in the transmission system.

IPM® uses a dynamic linear programming structure to determine the optimal combination of these options for each region by season and load segment. When determining how to generate electricity to meet a certain level of demand at minimum cost, available power stations need to be ranked according to their generation-specific operating costs and subject to each station's operational constraints. The cost components include fuel, emissions allowance if relevant, and operating and maintenance (O&M) costs. The fuel cost takes into account the fuel price, based on IPM's fuel market structure, and the technology-specific thermal efficiency (heat rate). IPM® sums these fuel costs and any adder for generation-specific operating and maintenance costs to define the hourly cost of generating a single unit of energy from each power station. Once these have been defined, the model dispatches as many resources as required. Notwithstanding other constraints, as detailed below, the lowest cost resources are dispatched first.

The transmission network can have a major impact on the order in which power stations will be dispatched in a region and its neighboring regions. IPM® captures transmission capabilities, constraints and bottlenecks in the transmission network. In some cases, lower cost generation resources may be available in a neighboring region. Subject to network constraints, these units may dispatch before units within the region. Similarly, more expensive electricity from a power station that has unhindered access to consumers in a region may be requested instead of cheaper power at the wrong side of a bottleneck.

Demand for electricity varies by time of day and across the days of the week in the manner defined by the load profile. In any single hour, the market clears at the point where supply meets the demand. This indicates which group of power stations will be dispatched to meet the required demand. The hourly cost of generation of the most expensive power station dispatched is identified as the marginal electricity, or market clearing, price for that region. IPM® will determine the market clearing price for load segments by season and year. Results of the optimization also include generation levels for different power stations, the amount of fuel consumed, and emission levels.

As demand for energy increases over time, or as existing resources retire due to constraints (discussed below), new power stations must be built. IPM® determines the optimal expansion plan by region based on the cost and performance of the options provided by the user and applicable constraints. IPM® may also add new capacity to meet reserve margin requirements. The model ensures that adequate reserve margin is maintained in each region or jointly across regions by delaying the retirement of existing power stations (if allowed within a regulatory construct) and/or choosing to build new technologies to make up any shortfall from existing capacity. IPM® determines the capacity price to meet reserve margin requirements in each region. That price is a premium that reflects the difference between annual fixed costs (including fixed operation and maintenance plus repayment on capital investments) and the expected profit stream (or margin) made from the sale of electricity. The latter requires the IPM® to make an informed decision about future dispatch and remuneration to all options, highlighting the interdependency of electricity dispatch and capacity expansion decisions.

2.3 IPM® Representation of Constraints

The dispatch, expansion and pricing projections are determined subject to several types of constraints, including environmental controls, generation standards (e.g., renewable portfolio standards), and fuel resources.

IPM® incorporates constraints on emissions of NO_X, SO_2, mercury, CO_2 and other pollutants into its optimization process. Constraints are specified on the basis of target emission rates, cap-and-trade programs covering multiple units, emission tariffs, or command-and-control policies, and applied to individual generating units or groups of units. Units subject to constraints have a variety of compliance options:

1. **Reduce Running Regime –** In order to comply with polices that allow for a reduction in absolute emissions such as an emissions cap rather than emission rates, a unit can limit its operational hours to more lucrative load segments to reduce exposure to allowance prices or to comply with unit-level tonnage limits.
2. **Fuel Switch –** Coal-fired units can choose from a variety of coals of different sulfur and mercury contents to minimize emissions and allowance cost impacts. The demand for these lower content coals result in premiums for those coals over coals with higher pollutant contents, although that premium may shrink if, for example, control becomes the dominant compliance option and higher content coals can be burned by controlled units. Oil units are generally offered fuels with different sulfur contents as well. The system may also fuel switch, from new coal builds to new gas builds, for example, to address CO_2 emissions requirements.
3. **Retrofit –** A variety of retrofit technologies are available to reduce emissions, including wet and dry scrubber options, activated carbon injection, and fabric filters. IPM® determines the optimal control plan based on the cost of control and going-forward dispatch and revenues of the affected units. Under a command-and-control regime, IPM® will weigh the value of retrofitting a unit against the cost of retiring that unit and replacing its generation and capacity in the system. Under a cap-and-trade program, the retrofit decision will be assessed relative to alternative costs of compliance across the system.

4. **Purchase Allowances –** By solving for an allowance price under cap-and-trade programs, IPM® is implicitly assuming that some units are sellers of allowances and others are buyers.
5. **Retire –** An existing power station that cannot recover its fixed costs of operation on an ongoing basis will be retired. IPM® will assess this closure option against the possibility that it may be less expensive to extend the life of the unit through control investments than to build a replacement power plant. Based on the relative economics of control, operation without control, if allowed under the specific environmental program, and capacity expansion, IPM® can assess which combination of retirement and new build options will result in the lowest possible generation and capital expenditure profile over time.

Units can comply with some programs using any combination of the first four options. For cap and trade programs, IPM® solves for allowance prices. Allowance prices reflect the cost of controlling the marginal unit affected by the program. Allowance prices in cap and trade markets are determined on the basis of the marginal cost of control for the affected group of units. The impacts of allowance banking, surrender ratios, and compliance decisions are also treated endogenously in IPM®.

Generation requirements that define a particular set of generation source types can also constrain IPM's decision-making. IPM® will account for renewable portfolio standards, for example, by adding sufficient qualifying renewable generation to meet the standards for a specific state or region. The generation characteristics of the selected generators, such as wind units, may also drive additional expansion requirements to meet reserve margin and generation needs. IPM® will project renewable energy credit prices that reflect the premiums over other sources of revenue necessary to develop the qualifying generation.

Dispatch decisions are also constrained by fuel resources. IPM® optimizes coal production, transportation, and consumption for coal units in the system based on supply curves that define resource cost and availability for several coal supply basins in the US and internationally. IPM® has coal types distinguished by rank and by sulfur and mercury content. There are multiple coal supply curves for each supply basin corresponding to the major coal quality types in that region. Each step on the coal supply curves includes both a production capacity and a coal resource limit. Each coal power plant in IPM® is assigned to a coal demand regions in IPM®. The coal demand regions are distinguished by location, mode of delivery, and captive versus non-captive status.

IPM® also contains supply curves and other natural gas market assumptions to reflect the cost and availability of natural gas. The supply curve accounts for the demand for gas in response to system dispatch decisions to generate projected commodity prices. IPM® applies price differentials based on seasonal gas demand and transportation costs from Henry Hub to determine the delivered price to every gas-fired generator in IPM®.

2.4 Additional IPM® Documentation

Additional documentation regarding the structure of IPM®, is available on the US EPA's website at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter2.pdf.

Chapter 3: RESULTS SUMMARY

An overview of the high-level results of the EEI modeling analysis conducted by ICF is described in this chapter, including the Retirements of coal capacity due to the modeled regulations, the New Builds that are built to replace the retired capacity as well as to meet load growth, the Retrofits that need to be installed on those coal plants that invest in the environmental controls and continue to run, and the Capital Expenditures associated with both the new builds and the retrofits. The results presented in this chapter are at the summary level and are for the coal units only. More detail can be found in Appendix C at the end of this document.

3.1 Retirements

The impending regulations, including HAPs MACT, 316(b) and ash will cause a number of coal plants to retire. While the overall number of the plant retirements observed in the analysis differs from scenario to scenario depending on the underlying policy, technology, and market variables, the fundamental logic that determines whether a plant retires remains the same. The retirement logic is driven by a comparison of the capital expenditures necessary to bring a certain plant into compliance as compared to the going forward revenues that plant can earn. Each unit's current control status is taken into account, as are the fuels available to it. Each unit is dispatched on an economic basis into the zone in which it operates, with each zone having its own electricity/capacity price based on the generation and load in that zone as well as the generation and load in surrounding regions, limited by the transmission transfer capability into and out of each zone. [1] Unlike market-based cap-and-trade mechanisms, the HAPs, ash and water regulations are command-and-control regulations that require units to make a binary decision of either meeting the requirements of the rules, or shutting down. The suite of technologies assumed to be required to meet the regulations is described in the scenario descriptions.

3.1.1 National-level retirements

The summary coal retirement results of the 10 scenarios analyzed are shown in Table 3.1 below, which contains data for:

- Planned Coal Retirements – those retirements announced by companies that are considered "firm" enough to be hardwired into the model. The planned coal retirements are consistent throughout all scenarios at 6 GW. It should be noted that these retirements represent those units that have announced firm retirements based on regulatory filings, press releases and EEI member company feedback. Due to the timing of this analysis, there have been subsequent announcements that are not captured in this list.
- Unplanned Coal Retirements – those retirements that are economic based on the modeling and the retirement logic as described above. The cumulative retirements are shown for two representative years, 2015 and 2020.

[1] A more detailed description of the IPM model is found in Chapter 2.

- Total Coal Retirements – sums the planned and unplanned coal retirements. The total number presents the total amount of coal capacity forecast under each scenario to be retired from the existing coal fleet.
- Incremental Coal Retirements – represents those retirements that are incremental to the retirements seen in the Reference Case. The incremental retirements present a picture of the direct impact of the Scenarios on coal retirements.

In addition to coal unit compliance, the analysis included HAPs MACT compliance requirements for oil/gas steam units and 316(b) compliance requirements for both oil/gas steam and nuclear units. Those results are included in Appendix C, while the data discussed below are for coal units only.

Table 3.1: National Coal Retirements (GW)

Run	Scenario	Planned Coal Retirements	Unplanned Coal Retirements		Total Coal Retirements		Incremental Coal Retirements	
		2015	2015	2020	2015	2020	2015	2020
1	Reference Case	6	16	19	22	25	0	0
2	Scenario 1	6	50	50	56	56	34	31
3	Scenario 1 + Alt Air	6	41	41	46	46	24	21
4	Scenario 1 + Alt Water	6	49	50	55	55	33	30
5	Scenario 2	6	73	90	79	95	57	71
6	Scenario 2 + Alt CO2	6	66	73	71	79	50	54
7	Scenario 2 + Alt Air	6	64	77	70	82	48	58
8	Scenario 2 + Alt Ash	6	75	96	81	101	59	76
9	Scenario 2 + $1.50 Gas	6	47	56	52	61	31	37
10	Scenario 2 + $3.00 Gas	6	33	36	38	41	17	17

Note that Total and Incremental numbers may not sum due to rounding.

As can be seen from Table 3.1, there are 6 GW of planned coal retirements in the Reference Case and that are hardwired throughout all the Scenarios. In the Reference Case, there are 16 GW of Unplanned or Economic Coal retirements forecast to occur between 2011 and 2015, growing to 19 GW in 2020. When added to the Planned Retirements, these sum to 22 GW and 25 GW in 2015 and 2020, respectively. These retirements are mostly due to state-level mercury policies and a generally low natural gas price forecast that make it uneconomic to continue to operate these typically smaller and older units. These retirements are forecast to occur absent any new air, ash and water regulations.

In the Policy Scenarios (Runs 2-10 in Table 3.1), there are between 33 and 75 GW of Unplanned Coal Retirements forecast by 2015 growing to between 36 and 96 GW of Unplanned Coal Retirements by 2020. When taken from a starting universe of approximately 311 GW of existing coal capacity, these unplanned retirements represent between 11 percent and 24 percent of the coal fleet in 2015 and between 12 percent and 31 percent of the fleet in 2020. When viewed from the perspective of the impact of the Policy Scenarios on Incremental Coal Retirements that are over and above the Reference Case, this number falls to between 5 percent and 19 percent of the fleet in 2015 and between 5 percent and 24 percent of the fleet in 2020.

It is worth noting that the number of retirements remains flat between 2015 and 2020 in all of the Scenario 1 runs, while it rises during that time in all of the Scenario 2 runs. This is due to the exclusion of a CO_2 policy in the Scenario 1 runs, so that any unit that is going to retire does so when faced with the initial decision to retrofit or retire. As HAPs MACT regulations are assumed to require controls in 2015, this represents the first hurdle that the coal units must overcome, while looking ahead to any additional expenditures that may be required of them from additional air, water and ash regulations. Plants that choose to invest in pollution control retrofits to comply with HAPs MACT do so with the "knowledge" that they can also invest in the air, ash and water requirements in 2018 and 2020, respectively, and continue to earn a positive return. (Note that while the policy developed by EEI members required fossil units to comply with 316(b) water requirements in 2022, it is represented as 2020 within the modeling construct.)

In the Scenario 2 runs, where a carbon price is included starting in 2017, the continued upward pressure of carbon on the coal plants' profitability results in a greater number of retirements, both initially and over time. Many of the plants that retire in 2020 for example in the Scenario 2 (CO_2) analyses may already be relatively well controlled for HAPs MACT, needing only some incremental investment (such as an ACI), but then retire after 2015 when faced with additional air, water and ash requirements, combined with thinning margins due to CO_2. The details regarding the specific scenarios are discussed below.

In Scenario 1, which contains the Base Air, Ash and Water regulatory scenario, but no CO_2, there are 50 GW of unplanned coal retirements in 2015, remaining flat through 2020. When added to the planned coal retirements, this sums to 56 GW of cumulative coal retirements in both years. When compared to the retirements occurring in the Reference Case, the Incremental Coal retirements due to Scenario 1 are forecast to be 34 GW in 2015 and 31 GW in 2020. The gap closes slightly as unplanned coal retirements rise between 2015 and 2020 in the Reference Case.

The Alternative Scenarios, Scenario 1 + Alt Air (Run 3) and Scenario 1 + Alt Water (Run 4), result in less retirements due to less stringent technology requirements for complying with the air and water regulations. In Run 3 (Scenario 1 + Alt Air), there are 41 GW of unplanned coal retirements in 2015 and 2020, as compared to the 50 GW of retirements observed in Scenario 1. In Run 4 (Scenario 1 + Alt Water), the results are largely similar to Scenario 1 with 49 and 50 GW of unplanned coal retirements by 2015 and 2020. It should be pointed out however, that the Alt Water scenario results in significantly less cooling tower retrofits to comply with regulations and also has less of an impact on the system in terms of derates. This is detailed further in the Retrofits section below.

The Scenario 2 Policy runs all include a CO_2 price in the forecast. How one thinks about CO_2 in planning future investments around coal units is of central importance to the economics of those investment decisions. The presence of a CO_2 price disadvantages coal relative to other, lower- or non-CO_2 emitting generating sources such as gas, nuclear and renewables. As gas-fired generation is often on the margin and sets, to one degree or another, the regional price into which units dispatch, having a CO_2 price reduces the margin that coal plants can realize in the market and therefore makes it harder for them to economically justify a large capital investment in environmental controls. On the whole, the Scenario 2 runs (excluding scenario runs 9 and 10, the high gas price sensitivities) all have higher retirements than the Scenario 1 runs, that exclude CO_2.

In Scenario 2 (Run 5), unplanned coal retirements are forecast to be 73 GW in 2015, growing to 90 GW in 2020. This is an increase of 23 GW in retirements in 2015 as compared to Scenario 1, and an increase of 40 GW in 2020. In Scenario 2 + Alt CO_2 (Run 6), when a lower CO_2 starting price of $10/ton is used, unplanned coal retirements are forecast to be 66 and 73 GW in 2015 and 2020, respectively, with the results falling, as expected, between the Scenario 1 no CO_2 policy and Scenario 2 CO_2 policy. The lower CO_2 price puts less pressure on coal margins and makes it more cost effective for additional units to retrofit rather than retire.

In Scenario 2 + Alt Air (Run 7), results are very similar to the Scenario 2 + Alt CO_2 run with 64 and 77 GW of unplanned coal retirements in 2015 and 2020, respectively. Allowing units 200 MW and smaller to retrofit with DSI/trona instead of an FGD, together with not requiring an SCR on units in the East, results in 9 GW less retirements of coal units, relative to Scenario 2. By 2020, the Alt Air Scenario results in 13 GW less coal retirements relative to Scenario 2.

Scenario 2 + Alt Ash (Run 8) represents the most stringent scenario analyzed in this study. As described in the Scenario Descriptions (see Appendix B), the Alt Ash scenario represents a Subtitle C treatment of the ash, requiring additional handling and disposal costs and impacting more units (i.e., even those that do not have wet-dry ash handling conversion issues). As this run has the most stringent requirements, we see the most retirements with 75 and 96 GW of unplanned coal retirements in 2015 and 2020, respectively.

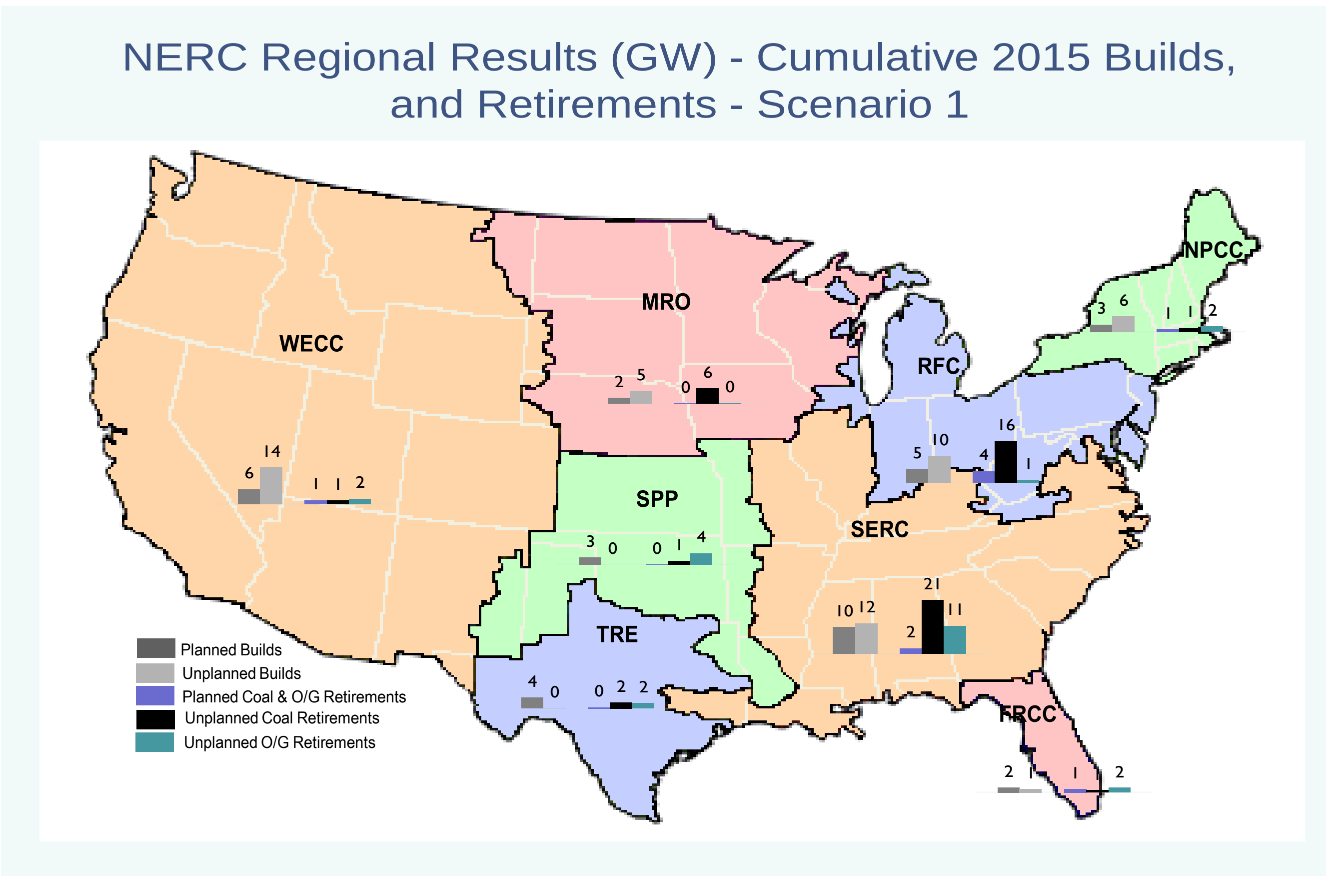
Another factor that plays a key role in determining the relative competitiveness of coal units and their ability to absorb capital expenditures and continue to run, or conversely retire, is the expectation for future natural gas prices. The higher the gas price, the more profitable a coal plant is and the greater its ability to recover any capital expenditures necessary to comply with the regulations. The natural gas prices in this analysis are responsive to the amount of coal capacity retired and the amount of gas generation called upon to fill the gap. The Reference Case gas price averages approximately $5.00/mmBtu in real 2008$ at Henry Hub over the 2015–2035 timeframe. In Scenario 1, with over 30 GW of incremental coal retirements relative to the Reference Case, gas prices are forecast to average $6.20/mmBtu over that same period. In Scenario 2, with incremental coal retirements of 57 and 71 GW above Reference Case levels in 2015 and 2020, respectively, forecast gas prices rise to almost $7.50/mmBtu over the 2015-2035 timeframe of the analysis. All else being equal, the higher natural gas prices serve as a feedback function, dampening the level of coal retirements.

The High Gas price scenarios – Scenario 2 +$1.50 gas (Run 9) and Scenario 2 + $3.00 gas (Run 10), see the least amount of coal retirements relative to the other Scenario 2 runs. With higher gas prices leading to higher power prices and therefore higher margins, coal units are more profitable and therefore better able to incur the capital expenditures associated with the environmental retrofits assumed to be necessary to comply with the specified air, ash and water regulations. In Scenario 2, gas prices average $7.50/mmBtu (real 2008$ at Henry Hub) over the 2015–2035 analysis period. In Scenario 2 + $1.50 gas, unplanned coal retirements are forecast to be 47 and 56 GW in 2015 and 2020, respectively. In Scenario 2 + $3.00 gas, with gas prices averaging $10.50/mmBtu, unplanned coal retirements fall to 33 and 36 GW over that same timeframe – or 17 GW more retirements than are seen in the Reference Case.

3.1.2 Regional-level retirements

The forecasted coal unit retirements are concentrated mostly in the SERC and RFC regions, where much of the existing coal capacity resides. The MRO region is also impacted. In Scenario 1, unplanned coal retirements in SERC are forecast to be 21 GW by 2015 and remain flat through 2020. In Scenario 2, these unplanned retirements increase to 31 and 38 GW in 2015 and 2020, respectively. In RFC, the Scenario 1 unplanned retirements forecast are to 16 GW in 2015, remaining flat through 2020, while in Scenario 2 the unplanned retirements increase to 21 and 24 GW over that same time period. An example of the 2015 results from Scenario 1 is presented below in Figure 3.1. A more complete set of maps for Scenarios 1 and 2, and data for all the Scenarios and sensitivities for 2015 and 2020, are included in Appendix C.

Figure 3.1 NERC Regional Results from Scenario 1



3.2 New Builds

New capacity will need to be built to both replace retired coal and oil/gas steam capacity, as well as to provide for anticipated load growth – both peak and energy. In the IPM® modeling framework used for this analysis, new capacity is brought online endogenously within the model in order to serve load and meet peak plus reserve margin requirements. The model selects among multiple new build options, as determined by EEI, including gas-fired combustion turbines (CT's), combined cycle (CC's), renewables (wind, solar, biomass, geothermal – as regionally applicable), nuclear, and coal with and without CCS. These new generation resources are built on a least-cost basis, taking into account capital, fixed operating and maintenance (FOM), variable operating and maintenance (VOM), fuel and emissions costs. The assumptions used for specifying the cost and performance characteristics of the new generation options that the model can choose from are included in Appendix A.

3.2.1 National-level builds

The summary build results for the 10 scenarios analyzed are presented in Table 3.2 below. The builds are a national-level aggregation across all capacity types, including gas, renewables, and nuclear. The detailed results by capacity type are presented in charts in Appendix C of this document. The table is constructed in a similar manner to the national-level retirement table presented in the previous section with the following categories:

- Planned Additions – those additions that have been announced by companies and are considered "firm" enough to be hardwired into the model. The planned additions are consistent throughout all scenarios at 35 GW. It should be noted that the builds represent those units that are under construction or meet two of the three following criteria:
    - Fully permitted
    - Signed a purchased power agreement (PPA)
    - Financed

  Given the fact that the three criteria can be difficult to find publicly the most common reason for inclusion is under construction status. Due to the timing of this analysis, there may have been subsequent announcements that are not captured in this list.
- Unplanned Additions – those builds that are economic based on the modeling and the build logic as described above. The cumulative builds are shown for two representative years, 2015 and 2020.
- Total Builds – sums the planned and unplanned builds. The total number presents the total amount of capacity forecast to be built by 2015 and 2020 to meet load in light of the retirements occurring in that scenario.
- Incremental Builds – represents those builds that are incremental to the builds seen in the Reference Case. The incremental builds present a picture of the impact of the Scenarios on builds.

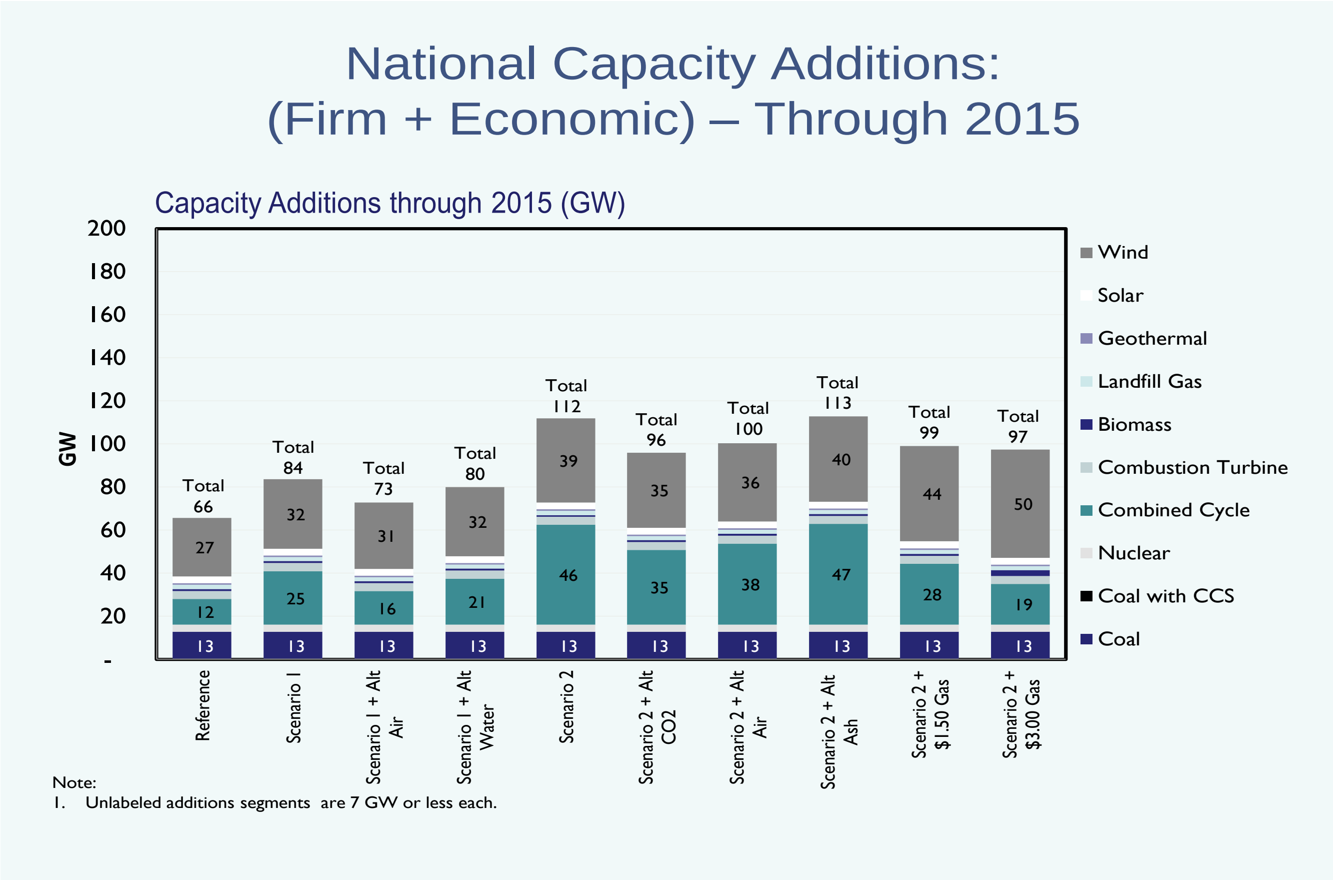
Table 3.2: National Capacity Additions (GW)

Run	Scenario	Planned Additions	Unplanned Additions		Total Additions		Incremental Additions	
		2015	2015	2020	2015	2020	2015	2020
1	Reference Case	35	30	48	66	89	0	0
2	Scenario 1	35	48	91	84	132	18	43
3	Scenario 1 + Alt Air	35	37	79	73	120	7	31
4	Scenario 1 + Alt Water	35	45	83	80	124	14	35
5	Scenario 2	35	77	125	112	165	46	76
6	Scenario 2 + Alt CO2	35	61	94	96	135	30	46
7	Scenario 2 + Alt Air	35	65	110	100	151	35	62
8	Scenario 2 + Alt Ash	35	77	129	113	170	47	81
9	Scenario 2 + $1.50 Gas	35	64	106	99	147	33	58
10	Scenario 2 + $3.00 Gas	35	62	103	97	144	32	54

Note that Total and Incremental numbers may not sum due to rounding.

In the Reference Case there are 30 GW of unplanned capacity additions by 2015, rising to 48 GW by 2020 that are forecast to be needed to serve system load above the 35 GW of Planned Additions. When added to the 35 GW of Planned Additions, these sum to the 66 GW and 89 GW of total capacity additions by 2015 and 2020 respectively. A portion of these additions is due to the 22–25 GW of coal retirements seen in the Reference Case, while the rest is due to load growth over time. As shown in Figure 3.2 below, of the 66 GW of total capacity added in the Reference Case by 2015, approximately 13 GW are "firm" coal that is already under construction, 12 GW are gas combined cycle units, 27 GW are wind, and the rest are made up of small amounts of gas combustion turbines, nuclear uprates and other renewables. By 2020, the total has grown to 89 GW with gas combined cycle units, firm nuclear and renewables making up most of the difference. Detailed national-level charts with the capacity addition mix by capacity type can be found in Appendix C of this document, along with regional-level planned and unplanned capacity additions.

Figure 3.2: National Capacity Additions per Scenario Through 2015



In the Policy Scenarios, unplanned additions are correlated to the coal retirements discussed in the prior section. As more coal is retired, more capacity has to be built to replace it. Overall, the capacity additions in Scenario 1 (without CO_2) and in the Air and Water sensitivities around it are lower than in Scenario 2 with CO_2 and the sensitivities around it, as less coal is retired in Scenario 1 and more coal is retired in Scenario 2.

In Scenario 1 and the Scenario 1 sensitivities (Runs 2-4), there are between 37 and 48 GW of unplanned capacity additions in 2015 and between 79 and 91 GW of unplanned capacity additions by 2020. The sensitivities to Scenario 1 that incorporate less stringent interpretations of the air and water regulations result in less coal retirements, as well as less derates of existing capacity, and therefore lesser need for new capacity additions.

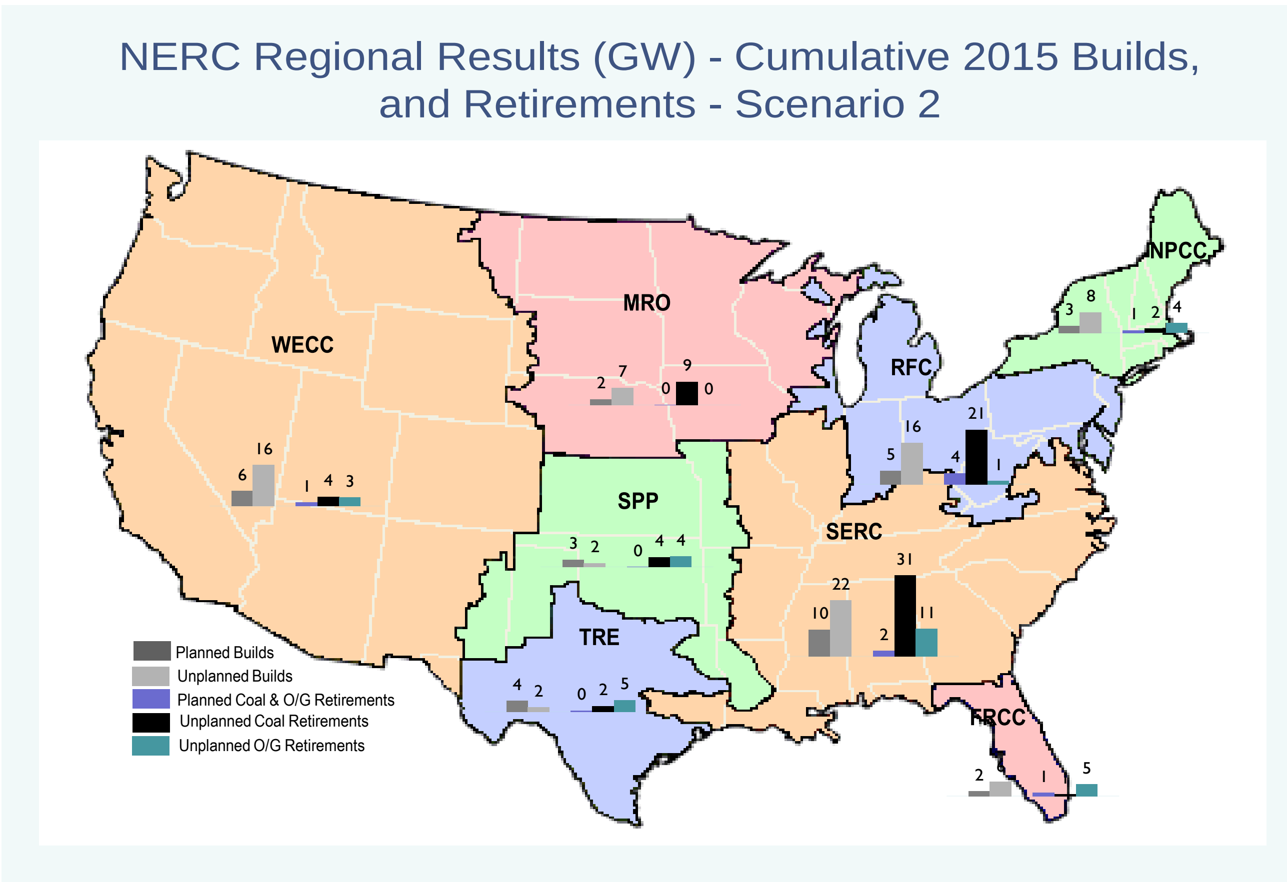
In Scenario 2, the forecast shows 77 and 125 GW of unplanned capacity additions in 2015 and 2020, respectively, as the system needs to compensate for retired capacity. In the Scenario 2 Alt CO_2 (starting at $10/ton instead of $25) and the Alt Air regulations (Runs 6 and 7), there are less capacity additions in response to the lower coal retirements, with the Alt CO_2 scenario resulting in fewer new builds relative to the Alt Air.

The Scenario 2 gas price sensitivities both produce similar total capacity addition patterns, with Run 10 (the + $3.00 high gas price scenario) resulting in more wind and, by 2020, nuclear capacity additions, as gas CC builds are reduced relative to the other scenarios.

3.2.2 Regional-level builds

Regional-level builds are directly, but not solely, related to the regional levels of retirements. Faster-growing regions over time need more capacity simply due to increased load growth that is independent of the amount of capacity retired. Figure 3.3 below shows regional-level capacity builds, along with the regional retirements by 2015 for Scenario 2. RFC and SERC see the most capacity builds, largely in response to the relatively large amount of coal retirements in those regions. WECC also sees significant builds, although this is more driven by load growth and state RPS requirements than by retirements.

Figure 3.3: NERC Regional Results from Scenario 2



3.3 Retrofits

The Air, Ash and Water regulations analyzed will result in many coal units needing to install environmental controls. These retrofits include SO_2 scrubbers (FGDs), ACI and Fabric Filters to meet HAPs MACT in the Base Air scenarios, while in the Alt Air Scenarios units 200 MW or less could install DSI instead of the more capital-intensive SO_2 scrubber. The Base Air scenario also required units in the East to install an SCR in 2018 to be considered fully controlled, while in the Alt Air Scenarios, a more stringent NO_X cap in the East was put in place in lieu of the SCR requirement. The Base Water scenario required cooling towers on all once-through thermal units, while the Alt Water scenario required cooling towers only on once-through units located on sensitive water bodies (defined as oceans, tidal rivers and estuaries). The Base Ash scenario required the closure of ash ponds, and the conversion of wet to dry handling under Subtitle D. The Alt Ash requirements required ash handling per Subtitle C, which both increased costs as well as the number of units that the regulations affect.

It should be noted that while there are 311 GW of existing coal capacity at the beginning of the forecast time horizon, the retrofit table contains much higher numbers of GW retrofits. This is due to the fact that a single coal unit can install multiple types of retrofits. If, for example, a 300-MW coal unit installed an FGD and a fabric filter, it appears in the table below as 600 MW of retrofit installation. If that same coal unit also installed an ACI in addition to the FGD and fabric filter, it would be counted as 900 MW. The table therefore captures GW of environmental control retrofits installed, not GW of coal plants. It should also be noted that many of the retrofits result in a capacity or heat rate penalty to the unit due to parasitic load. These penalties are specified in Appendix A, and are taken into account in the analysis, but are not specifically reported in the retrofit or retirement data presented.

Retrofits in response to the Policy scenarios occur at different times, in line with the policy implementation dates assumed in the analysis. HAPs MACT requires compliance by 2015, while ash and fossil water policies assume compliance in the 2018 to 2022 timeframe, with the results appearing in the 2020 retrofit data. In addition to coal unit compliance, the analysis included HAPs MACT compliance requirements for oil/gas steam units and 316(b) compliance for both oil/gas steam and nuclear units. Those results are included in Appendix C, while the data discussed below are for coal units only.

3.3.1 National-level retrofits

The summary coal retrofit results of the 10 scenarios analyzed are shown in Table 3.3 below. The table contains data for:

- Planned Coal Retrofits – those retrofits announced by companies and are considered “firm” enough to be hardwired into the model. The planned coal retrofits are consistent throughout all scenarios at 81 GW. It should be noted that these retrofits represent controls on units that have announced firm retrofits based on regulatory filings, press releases and EEI member company feedback. Due to the timing of this analysis, there have been subsequent announcements that are not captured in this list.
- Unplanned Coal Retrofits – those retrofits that are economic based on the modeling and the retrofit logic as described above. The cumulative retrofits are shown for two representative years, 2015 and 2020.
- Total Coal Retrofits – sums the planned and unplanned coal retrofits. The total number presents the total amount of environmental retrofit installations installed on the coal fleet through 2015 and 2020.
- Incremental Coal Retrofits – represents those retrofits that are incremental to the retrofits seen in the Reference Case. The incremental retrofits present a picture of the impact of the Scenarios on coal retrofits.

Table 3.3: National Pollution Control Installations (GW)

Run	Scenario	Planned Retrofits	Unplanned Coal Retrofits		Total Coal Retrofits		Incremental Coal Retrofits	
		2015	2015	2020	2015	2020	2015	2020
1	Reference Case	81	26	47	107	127	0	0
2	Scenario 1	81	286	611	367	691	260	564
3	Scenario 1 + Alt Air	81	306	565	386	646	280	518
4	Scenario 1 + Alt Water	81	289	532	369	613	263	486
5	Scenario 2	81	244	504	325	584	218	457
6	Scenario 2 + Alt CO2	81	259	542	339	622	233	495
7	Scenario 2 + Alt Air	81	264	479	345	560	238	432
8	Scenario 2 + Alt Ash	81	241	588	322	669	215	542
9	Scenario 2 + $1.50 Gas	81	287	611	368	691	261	564
10	Scenario 2 + $3.00 Gas	81	312	677	392	757	286	630

Note that Total and Incremental numbers may not sum due to rounding.

Beyond the 81 GW of firm retrofit installations, an additional 26 GW of unplanned coal retrofit installations are forecast to be needed in 2015, rising to 47 GW in 2020, to comply with Reference Case requirements. Planned and Unplanned Reference Case retrofits installations on coal units therefore sums to 107 GW and 127 GW by 2015 and 2020, respectively. These retrofits are due primarily to the existing CAIR program as well as in response to state-level mercury and other emissions rules.

In most policy scenarios, the number of retrofits is inversely correlated to the amount of coal retirements in each scenario. The more coal capacity that retires, the less there is to retrofit. Put another way, the more stringent the policy requirements, and especially in light of an assumed future CO_2 policy and generally low gas prices, the less coal units are able to afford the capital expenditures associated with the environmental retrofits.

In Scenario 1 and the Scenario 1 sensitivities, unplanned coal retrofits range from 286 to 306 GW in 2015, increasing to 532 to 611 GW in 2020. Relative to those controls already being installed in the Reference Case, this represents 260–280 GW of incremental retrofits in 2015 and 486–564 GW in 2020. The Scenario 1 + Alt Water scenario is unique in that while it requires many less GW of cooling tower installations – 9 GW vs. 97 GW in Scenario 1 – it leads to only a slight reduction in coal retirements. Instead, its savings are in the form of reduced parasitic load on the system, thereby requiring less new capacity builds.

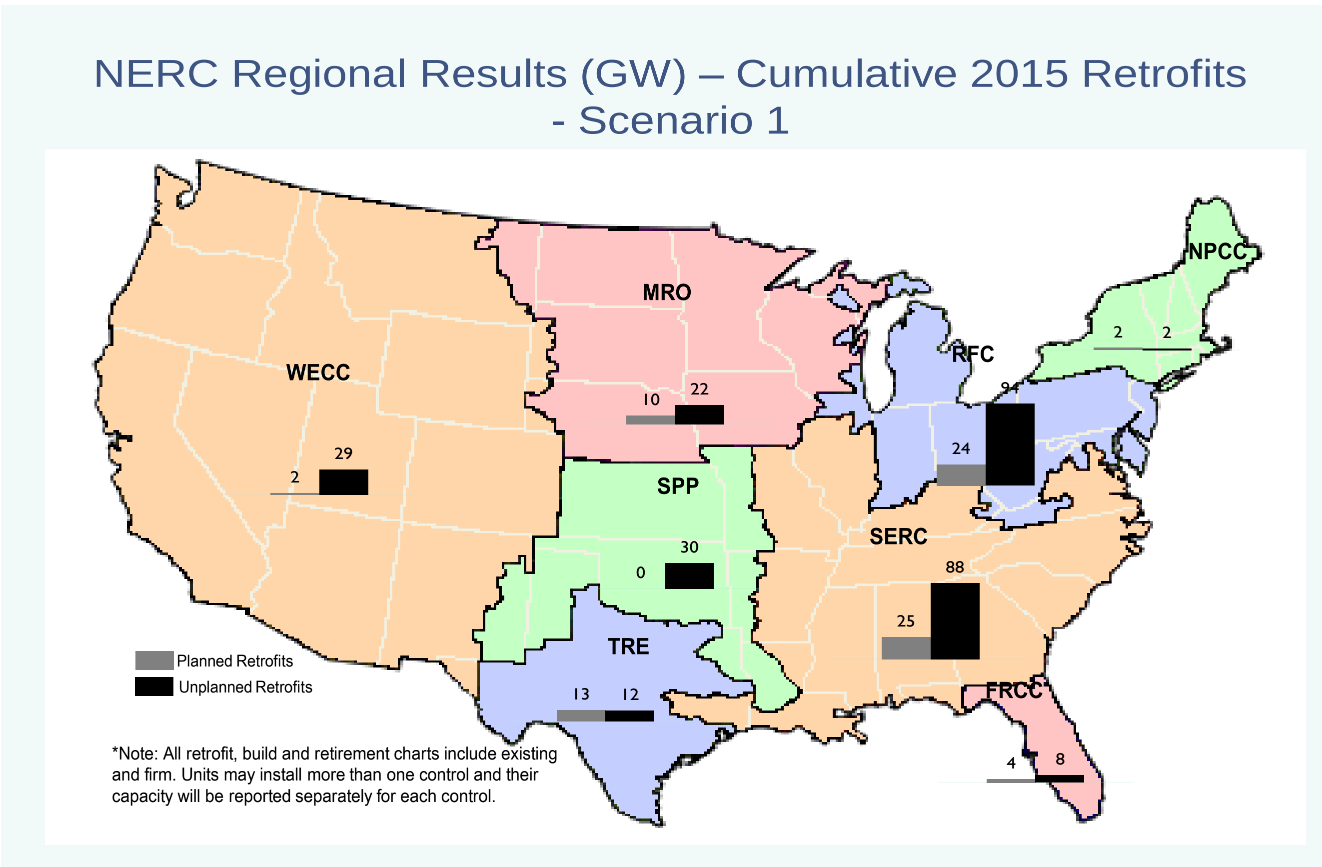
In Scenario 2 and the Scenario 2 Policy and Technology sensitivities (Runs 5–7), retrofits in 2015 are slightly lower than those in Scenario 1 as more units cannot justify the environmental capex in light of the assumed risk of CO_2, and find it economic to retire rather than retrofit. In these scenarios, retrofit installations range between 244 and 264 GW in 2015, and 479 to 542 GW in 2020. The Scenario 2 + Alt Ash, which represents the most stringent scenario analyzed, results in a higher amount of retrofits than the other Scenario 2 sensitivities (with the exception of the gas sensitivities), due to the fact that, despite the higher level of retirements, the Subtitle C ash policy in that scenario results in more units having to modify their ash handling methods.

The Scenario 2 +$3.00 high gas-price sensitivity results in the least amount of retirements and therefore the most retrofits in any of the scenarios. The + $1.50 gas sensitivity produces retrofit results very similar to those in Scenario 1, indicating that the increased gas price and its impact on increasing coal unit margins is effectively "counteracting" the CO_2 price pressure working to reduce those margins.

3.3.2 Regional-level retrofits

The regional-level retrofits are concentrated mostly in SERC and RFC, with additional amounts in SPP, WECC, MRO and ERCOT along with the other regions. A map showing regional retrofits in 2015 is shown in Figure 3.4 below. Detailed regional data summaries of retrofits in 2015 and 2020 are included in Appendix C.

Figure 3.4: 2015 NERC Regional Results from Scenario 1



3.4 Cumulative Capex for Retrofits and Builds

The summary cumulative capital expenditure results for the10 scenarios analyzed are shown in Table 3.4 below. The table contains data for:

- Coal unit retrofits – cumulative overnight capital costs plus allowance for funds used during construction (AFUDC)/interest capitalized during construction (IDC) through 2015 and 2020

- New capacity builds – cumulative overnight capital costs plus AFUDC/IDC through 2015 and 2020
- Total Capex – sums the capital expenditure on coal unit retrofits and new capacity builds
- Incremental Total Capex – represents the increase in capex for builds and retrofits relative to the Reference Case.

All expenditures are presented in real 2008 billion of dollars.

Table 3.4: Cumulative CAPEX for Retrofits and New Builds (Billion 2008$)

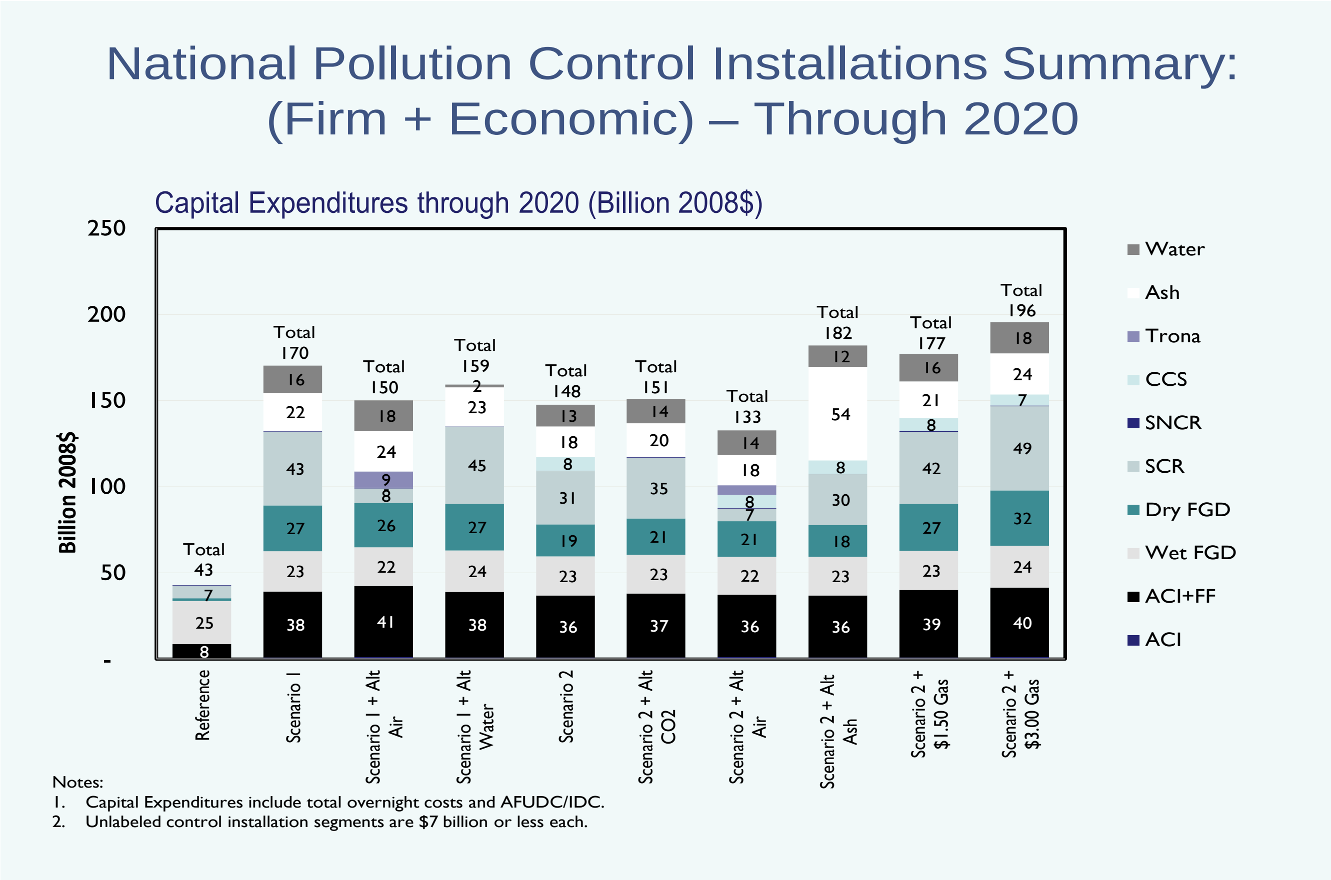
Run	Scenario	Retrofits		New Builds		Total		Incremental Total	
		2015	2020	2015	2020	2015	2020	2015	2020
1	Reference Case	36	43	146	211	182	254	0	0
2	Scenario 1	96	170	171	258	267	429	85	175
3	Scenario 1 + Alt Air	107	150	158	245	264	395	83	141
4	Scenario 1 + Alt Water	97	159	167	250	264	409	82	155
5	Scenario 2	85	148	210	313	295	461	113	206
6	Scenario 2 + Alt CO2	88	151	188	267	276	418	94	164
7	Scenario 2 + Alt Air	92	133	195	296	287	429	105	175
8	Scenario 2 + Alt Ash	84	182	212	319	296	501	114	247
9	Scenario 2 + $1.50 Gas	97	177	202	308	299	485	117	231
10	Scenario 2 + $3.00 Gas	104	196	206	329	310	525	129	270

Note that Total and Incremental numbers may not sum due to rounding.

In the Reference Case, the total capital expenditures on retrofit installations and new builds total $182 billion in 2015, rising to $254 billion 2020. The majority of those expenditures is for new generation capacity, and this is true for the policy scenarios as well, although the expenditure on retrofits relative to new builds rises in the policy scenarios relative to the Reference Case.

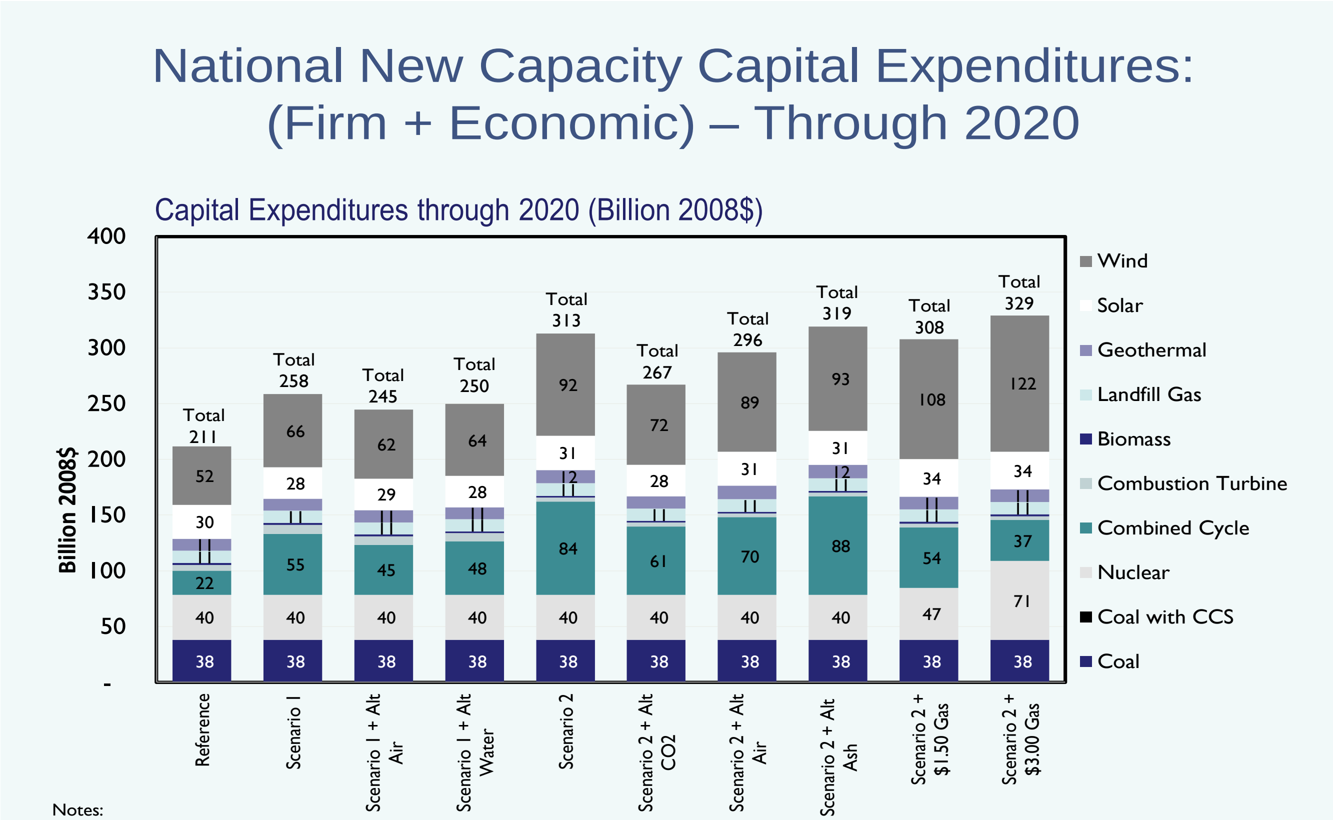
Unsurprisingly, the capital spent on retrofits is directly related to the amount of capacity retrofit, while the capital spent on new builds is directly related to the amount of capacity added, although the change in retrofit mix between Scenarios also has an impact. In all Policy Scenarios, cumulative capex on retrofits ranged from $84–$107 billion in 2015 and from $133–$196 billion in 2020. The detailed data for 2020 are shown in Figure 3.5 below.

Figure 3.5: 2020 National Retrofit Capex through 2020



Cumulative capex on new builds in the Policy Scenarios ranges from $158 billion to $212 billion in 2015 and from $245 billion to $329 billion in 2020. When compared to the Reference Case, incremental total capital expenditures by 2020 on both retrofits and new builds range from $114 to $247 billion in the policy and technology sensitivity scenarios. The highest incremental expenditure reaches $270 billion in the + $3.00 gas scenario, where both retrofit and new build expenditures are the highest due to the large amount of retrofits on existing coal units and high capital expenditures on new nuclear and renewable capacity in light of the very high gas prices. Detailed data for 2020 are shown in Figure 3.6 below. Additional data containing the capital expenditures on retrofits, as well as new capacity, can be found in Appendix C.

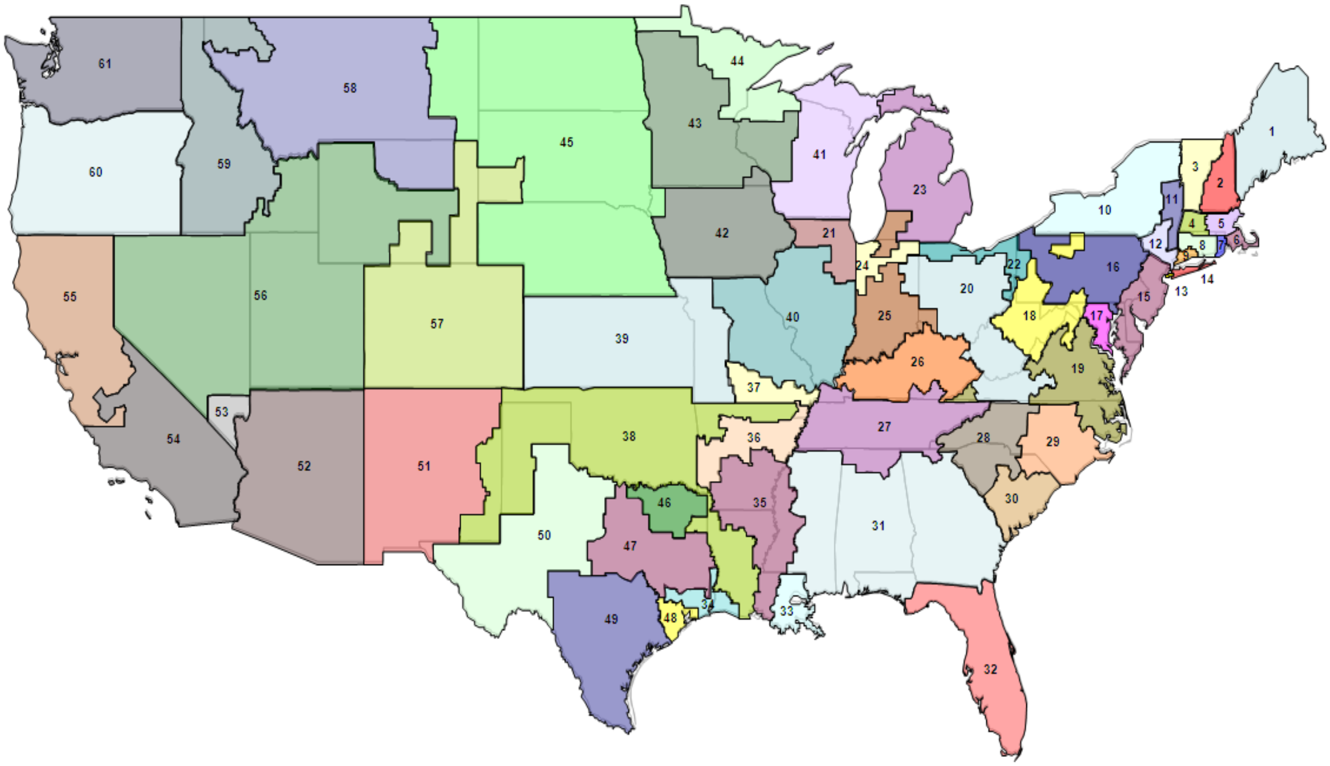
Figure 3.6: 2020 National Capacity Addition Capex through 2020



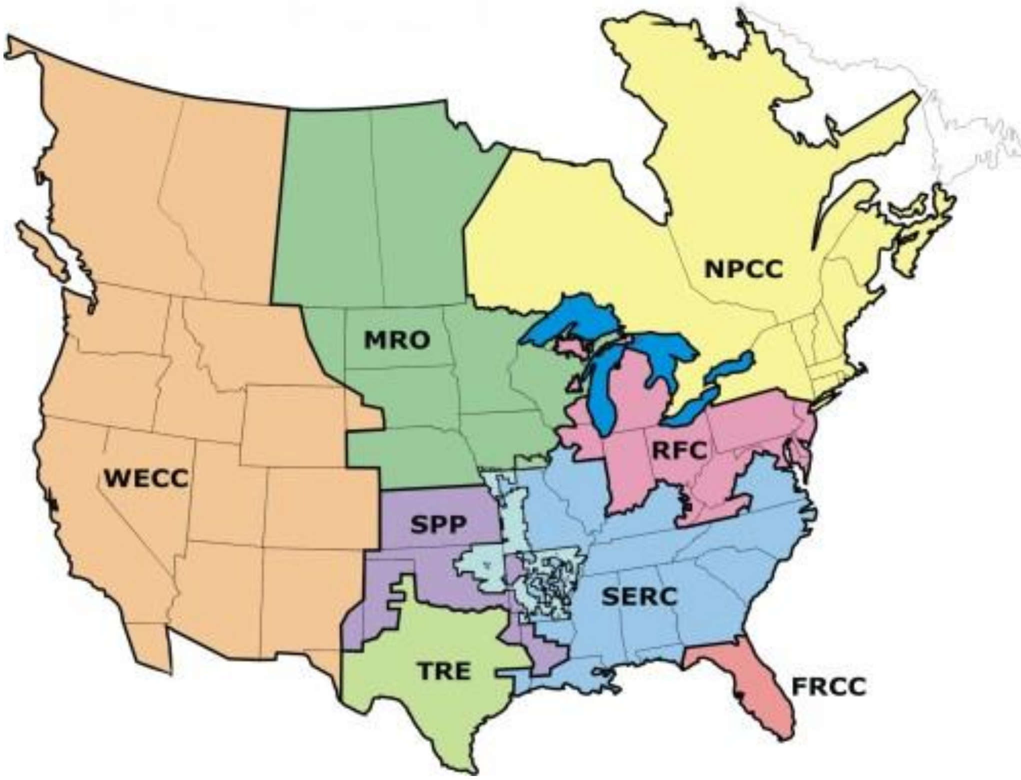
Notes:
1. Capital Expenditures include total overnight costs and AFUDC/IDC.
2. Unlabeled control installation segments are $10 billion or less each.
3. Capital Expenditures for renewable builds are decremented consistent with EPA's treatment of the PTC and ITC.

Appendix A: ASSUMPTIONS

IPM Modeling Regions



NERC Region Map



**FRCC – Florida Reliability Coordinating Council	**SERC** –SERC Reliability Corporation
MRO – Midwest Reliability Organization	**SPP** – Southwest Power Pool, RE
NPCC – Northeast Power Coordinating Council	**TRE** – Texas Regional Entity
RFC – Reliability First Corporation	**WECC** – Western Electricity Coordinating Council
Note: NERC regional results include the US only	

Run Year Structure

Run Year	Mapped Years
2010	2010
2011	2011
2012	2012
2013	2013
2014	2014
2015	2015
2016	2016
2017	2017
2018	2018
2019	2019
2020	2020-2022
2025	2023-2027
2032	2028-2035

Electricity Demand

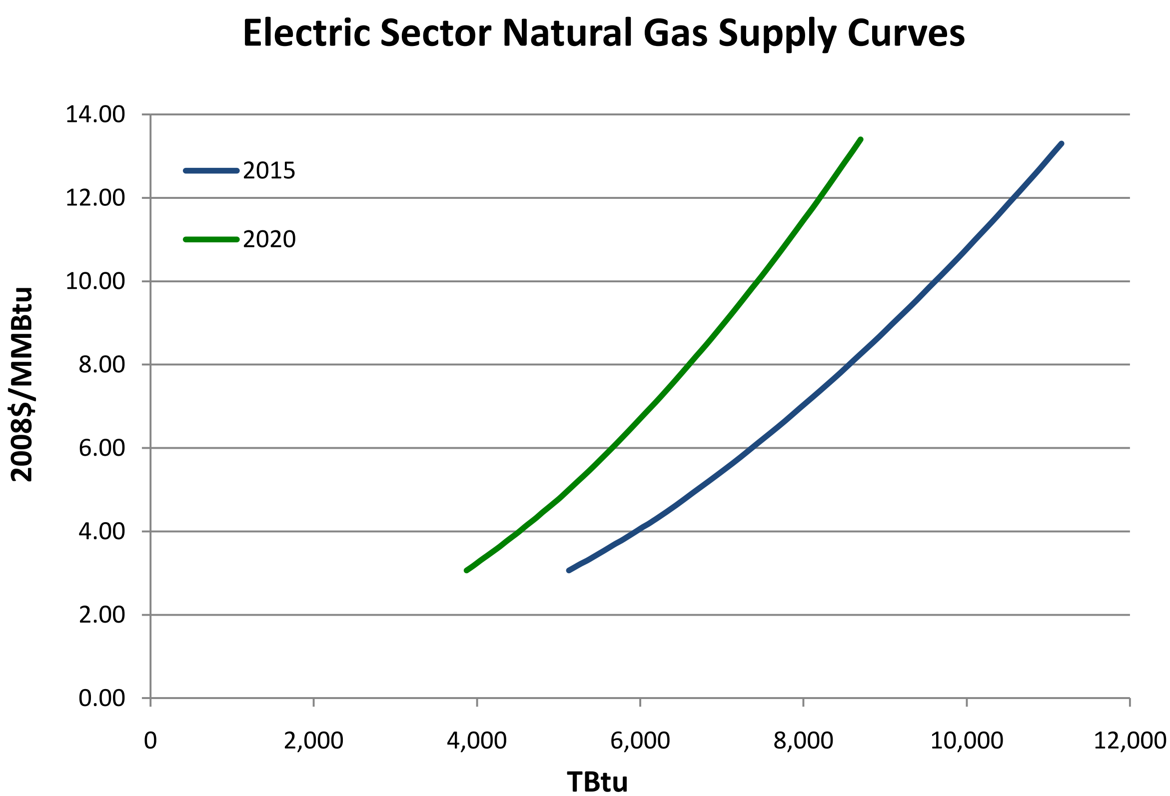
	Net Energy for Load (Billion kWh)		Net Internal Peak Demand (GW)	
	Non-CO2 Cases	CO2 Cases	Non-CO2 Cases	CO2 Cases
2010	3,869	3,869	713	713
2011	3,977	3,977	751	751
2012	4,043	4,043	761	761
2013	4,043	4,043	764	764
2014	4,061	4,061	769	769
2015	4,086	4,086	774	774
2016	4,124	4,124	781	781
2017	4,161	4,148	789	785
2018	4,207	4,159	799	789
2019	4,259	4,168	810	792
2020	4,302	4,198	819	800
2021	4,336	4,220	828	806
2022	4,369	4,232	836	810
2023	4,406	4,242	845	814
2024	4,452	4,269	854	819
2025	4,495	4,296	864	826
2026	4,543	4,330	875	833
2027	4,588	4,356	885	840
2028	4,633	4,374	895	845
2029	4,666	4,384	903	849
2030	4,703	4,379	912	849
2031	4,739	4,377	920	850
2032	4,778	4,377	929	851
2033	4,813	4,385	937	854
2034	4,855	4,395	946	857
2035	4,899	4,407	956	860
Avg Growth Rate	0.95%	0.52%	1.18%	0.75%

Notes:

1. Net Energy for Load and Net Internal Peak Demand are same as EPA v4.10 and AEO 2010 for the non-CO_2 cases. For the CO_2 cases, demand reductions start in 2017, the year the CO_2 policy starts, consistent with the percent reductions in the EPA American Power Act analysis.

Natural Gas Supply and Prices

For this analysis natural gas supply curves were constructed from the EPA v4.10 "proxy" curves provided for 2015 and 2020 found in the EPA v4.10 modeling documentation (*http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/v410/Chapter10.pdf*), and natural gas prices were a model output. Below are the natural gas supply curves for 2015 and 2020 used in this analysis.



Coal Supply and Prices

The EPA v4.10 coal supply curves and transportation costs were used for this analysis and the coal prices were solved for each supply region. For more information on the coal supply curves, see the detailed EPA v4.10 documentation (*http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/v410/Chapter9.pdf*).

The only change to the EPA v4.10 coal assumptions was an increase in the Gulf Lignite Hg content, per EEI member input. Below are the coal Hg contents used in this analysis.

Coal Type by Sulfur Grade	Fuel Code	Hg Emission Factors by Coal Sulfur Grades (lbs/TBtu)		
		Cluster #1	Cluster #2	Cluster #3
Low Sulfur Eastern Bituminous	BA	3.19	4.37	--
Low Sulfur Western Bituminous	BB	1.82	4.86	--
Low Medium Sulfur Bituminous	BD	5.38	8.94	21.67
Medium Sulfur Bituminous	BE	19.53	8.42	--
High Sulfur Bituminous	BG	7.10	20.04	14.31
High Sulfur Bituminous	BH	7.38	13.93	34.71
Low Sulfur Subbituminous	SA	4.24	5.61	--
Low Sulfur Subbituminous	SB	6.44	--	--
Low Medium Sulfur Subbituminous	SD	4.43	--	--
Low Medium Sulfur Lignite	LD	7.51	31.00	--
Medium Sulfur Lignite	LE	13.55	32.80	--
High Sulfur Lignite	LG	43.00	--	--

New Build Cost and Performance

Notes:
1. Overnight capital costs, variable O&M, fixed O&M, and heat rates are from EPA v4.10.
2. Wind and Landfill Gas are modeled in several different cost and resource categories.

Overnight Capital Costs (2008$/kW)					
	2012	2015	2020	2025	2032
SCPC	2,980	2,980	2,980	2,980	2,980
IGCC	3,335	3,335	3,335	3,335	3,335
IGCC with CCS	4,821	4,821	4,821	4,821	4,821
Nuclear	4,720	4,720	4,720	4,720	4,720
Adv. CC	997	997	997	997	997
Adv. CT	713	713	713	713	713
Biomass CFB	4,798	4,798	4,798	4,798	4,798
Biomass IGCC	4,158	4,158	4,158	4,158	4,158
Landfill Gas	2,548	2,739	2,558	2,297	2,062
Solar PV	5,888	6,152	5,464	4,571	3,857
Solar Thermal	4,897	5,029	4,355	3,690	3,110
Wind	1,920	2,066	1,953	1,775	1,614

	Heat Rate (Btu/kWh)	VO&M (2008$/MWh)	FO&M (2008$/kW-yr)	First Year Allowed
SCPC	8,874	3.50	29.52	2016
IGCC	8,424	1.35	48.92	2016
IGCC with CCS	10,149	1.71	61.79	2020
Nuclear	10,400	0.79	94.37	2020
Adv. CC	6,810	2.62	14.71	2015
Adv. CT	10,720	3.67	12.56	2013
Biomass CFB	13,500	11.85	87.02	2013
Biomass IGCC	9,800	9.02	49.33	2019
Landfill Gas	13,648	0.01	116.80	2013
Solar PV	NA	-	11.94	2012
Solar Thermal	NA	-	58.05	2013
Wind	NA	-	30.98	2013

Retrofit Cost and Performance

Retrofit Capital Costs (2008$/kW)								
MW	Wet FGD	Dry FGD w/ FF	SCR	SNCR	Pulse Jet Fabric Filter	ACI	ACI w/ FF	ESP for Oil Units
25	799	697	492	33	497	28	525	153
100	799	697	492	30	438	27	465	143
125	750	655	486	28	418	27	445	136
150	713	622	479	27	398	26	425	130
175	682	595	473	26	379	26	405	125
200	657	573	467	25	359	26	385	121
225	635	554	461	23	339	25	365	118
250	616	538	455	22	320	25	345	115
275	600	523	449	21	300	25	325	112
300	585	510	443	20	292	24	316	109
325	572	499	436	19	285	24	308	107
350	560	489	430	17	277	23	300	105
375	549	479	424	16	269	23	292	103
400	539	470	418	15	262	22	284	101
425	530	462	412	14	254	21	275	100
450	522	455	406	12	246	21	267	98
475	514	448	400	11	239	20	259	97
500	506	442	393	10	231	20	251	95
525	499	435	387	10	225	19	244	94
550	493	430	381	10	219	19	237	93
575	486	424	375	10	213	18	231	92
600	481	419	369	10	207	17	224	91
625	475	402	363	10	200	17	217	90
650	470	402	357	10	194	16	210	89
675	465	402	350	10	188	15	204	88
700	460	402	344	10	182	15	197	87
725	455	402	335	10	182	15	197	86
750	451	402	326	10	182	15	197	85
775	447	402	317	10	182	15	197	85
800	443	402	307	10	182	15	197	84
825	439	402	298	10	182	15	197	83
850	435	402	289	10	182	15	197	82
875	432	402	280	10	182	15	197	82
900	428	402	270	10	182	15	197	197

Note: For non-fluidized bed combustion (FBC) units, EPA offers SNCR to units >= 25 MW or < 200 MW. For FBC units, EPA offers SNCR to units >= 25 MW. The costs shown in the table above are for FBC units. The EEI analysis will assume the same size limitations.
Sources: EPA v4.10 for Wet FGD and Dry FGD; EVA for the rest.

Retrofit Fixed O&M (2008$/kW)							
MW	Wet FGD	Dry FGD w/ FF	SCR	SNCR	Pulse Jet Fabric Filter	ACI	ACI w/ FF
25	23.3	17.2	2.6	0.7	3.7	0.4	3.1
100	23.3	17.2	2.6	0.6	3.3	0.4	3.1
125	19.8	14.7	2.1	0.6	3.1	0.4	3.1
150	17.4	13.1	1.7	0.5	3.0	0.4	3.1
175	15.6	11.8	1.5	0.5	2.8	0.4	3.1
200	14.3	10.9	1.3	0.5	2.7	0.4	3.1
225	13.2	10.1	1.2	0.5	2.5	0.4	3.1
250	12.3	9.5	1.0	0.4	2.4	0.4	3.1
275	11.6	9.0	0.9	0.4	2.2	0.4	3.1
300	11.0	8.5	0.9	0.4	2.2	0.4	3.1
325	10.5	8.2	0.8	0.4	2.1	0.4	3.1
350	10.0	7.8	0.7	0.3	2.1	0.4	3.1
375	9.6	7.6	0.7	0.3	2.0	0.4	3.1
400	9.3	7.3	0.6	0.3	2.0	0.4	3.1
425	8.9	7.1	0.6	0.3	1.9	0.4	3.1
450	8.7	6.9	0.6	0.2	1.8	0.4	3.1
475	8.4	6.7	0.5	0.2	1.8	0.4	3.1
500	8.2	6.5	0.7	0.2	1.7	0.4	3.1
525	8.9	6.3	0.7	0.2	1.7	0.4	3.1
550	8.7	6.2	0.7	0.2	1.6	0.4	3.1
575	8.5	6.1	0.6	0.2	1.6	0.4	3.1
600	8.2	5.9	0.6	0.2	1.5	0.4	3.1
625	8.1	5.7	0.6	0.2	1.5	0.4	3.1
650	7.9	5.6	0.6	0.2	1.5	0.4	3.1
675	7.7	5.6	0.5	0.2	1.4	0.4	3.1
700	7.6	5.5	0.5	0.2	1.4	0.4	3.1
725	7.4	5.5	0.5	0.2	1.4	0.4	3.1
750	7.3	5.4	0.5	0.2	1.4	0.4	3.1
775	7.1	5.4	0.5	0.2	1.4	0.4	3.1
800	7.0	5.3	0.4	0.2	1.4	0.4	3.1
825	6.9	5.3	0.4	0.2	1.4	0.4	3.1
850	6.8	5.3	0.4	0.2	1.4	0.4	3.1
875	6.7	5.2	0.4	0.2	1.4	0.4	3.1
900	6.6	5.2	0.4	0.2	1.4	0.4	3.1

Note: For non-FBC units, EPA offers SNCR to units >= 25 MW or < 200 MW. For FBC units, EPA offers SNCR to units >= 25 MW. The costs shown in the table above are for FBC units. The EEI analysis will assume the same size limitations.
Source: EPA v4.10 for Wet FGD, Dry FGD, and SCR; EVA for the rest.

	Wet FGD	Dry FGD w/ FF	SCR	SNCR	Pulse Jet Fabric Filter	ACI
Variable O&M (2008$/MWh)	1.88	2.42	1.23	1.235	0.025	Bit - 0.84; Sub, Lig - 1.38
Derating/Energy Penalty	1.67%/1.7%	1.32%/1.33%	0.56%/0.56%	0%	0.75%	0.00%
% Removal	SO2 - 95%	SO2 - 90%	NOx - 85%	NOx - 30%	PM - 99.95%	Hg - 90% Bit, Sub; 70% Lig
Emission Rate Floor	0.06 lb SO2/MMBtu	0.09 lb SO2/MMBtu	0.06 lb NOx/MMBtu			
Restrictions		<= 1% Sulfur		Non-FBC Units < 200 MW		
First Year Allowed	2015	2015	2014	2013	2012	2012

Notes:

1. VO&M and performance assumptions from EPA v4.10, EVA, and EEI members.
2. All bituminous and sub-bituminous units must have ACI+FF to achieve 90% Hg removal from input. Lignite units must have scrubber+ACI+FF to achieve 70% removal from input.
3. Cost and performance represents system averages while site-specific cost and performance could vary +/- 25% or more.
4. Capital costs are all-in costs, including financing and owners costs.
5. PJFF costs include additional induced draft (ID) fan and duct work.
6. Scrubber (Wet and Dry) variable O&M includes sludge removal, reagents, and water.
7. SCR variable O&M includes reagents
8. Dry FGD restriction based on discussions on 3/31 with EEI members.
9. The capital costs for ESPs for oil units were estimated using an EEI member's retrofit cost for one plant and were scaled for size using the FGD curve.
10. First Year Allowed assumes construction time only and does not include any time allowance for permitting.

CCS Retrofits for Existing Coal Units		
Applicability (Original MW Size)	**450-750 MW**	**> 750 MW**
Incremental Capital Cost (2008$/kW)	2,014	1,633
Incremental FOM (2008$/kW-yr)	3.06	2.02
Incremental VOM (2008$/kW-yr)	2.40	2.40
Capacity Penalty (%)	25%	25%
Heat Rate Penalty (%)	33%	33%
CO_2 Removal (%)	90%	90%

Source: EPA v4.10

Dry Sorbent Injection	
Capacity (MW)	**Capital Cost (2008$/kW)**
25	42.35
50	41.80
75	41.26
100	40.72
125	40.17
150	39.63
175	39.17
200	38.54
FOM (2008$/kW-yr)	3.19
VOM - Bit (2008$/MWh)	9.20
VOM - Sub, Lig (2008$/MWh)	4.17
SO_2 Removal	70%
HCl Removal	>90%
Capacity Penalty	0.02%
Heat Rate Penalty	0.02%

Source: Informed from United Conveyor Corporation and ADA Environmental Solutions reports.

RCRA Subtitle D Costs			
	Component	**Cost**	**Units**
Capital Costs	Dry Fly Ash Handling	23	MM$/Unit
	Dry Bottom Ash Handling	20	MM$/Unit
	Waste Water Treatment without FGD	80	MM$/Plant
	Waste Water Treatment with FGD	200	MM$/Plant
	Dewatering Facility for FGD solids (17 plants)	35	MM$/Plant
FO&M Costs	Dry handling without FGD	3.0	MM$/Plant/Yr
	Dry handling with FGD	4.5	MM$/Plant/Yr
VO&M Costs	Fly ash, bottom ash, and FGD solids handling	2.00	$/Ton of Ash

RCRA Subtitle C Costs - Incremental to Subtitle D		
Capital Costs ($/Plant)	**1600 MW Plant**	**400 MW Plant**
Bottom Ash Management		
All Plants	1,890,000	1,050,000
Economizer/Fly Ash Management		
Plants with ESP Enclosure (Northern Plants)	8,840,000	3,810,000
Plants without ESP Enclosure (Southern Plants)	14,520,000	6,250,000
FGD By-product/Gypsum Management System		
Plants with Gypsum Containment Building	11,120,000	8,280,000
Plants without Gypsum Containment Building	22,540,000	14,650,000
Plants with Sulfite Producing FGD System	19,390,000	12,130,000
Land Storage/Landfill Upgrades to RCRA Standards		
All Plants	7,390,000	5,623,000
Pond Closure		
Active Pond Closure	9,620,000	9,620,000
Inactive Pond Closure	10,700,000	10,700,000
Wastewater Treatment System		
Plants with FGD	85,700,000	33,600,000
Plants without FGD	24,900,000	10,800,000
Miscellaneous Operational/Administrative Upgrades		
All Plants	5,765,000	2,125,000
Fixed O&M Costs - ($/Plant/yr)	**1600 MW Plant**	**400 MW Plant**
Landfill O&M	322,000	161,000
Miscellaneous O&M	4,573,000	1,524,000

Source: EOP Group and EPRI Studies

Cooling Tower Capital Costs ($/gpm)		
Fossil	319	
Nuclear	459	
Cooling Tower Energy Penalties		
NERC Sub-Region	**% Heat Rate Increase**	**% Capacity Reduction**
ERCOT	0.80%	2.50%
FRCC	0.90%	2.50%
US MRO	1.40%	3.10%
ISO NE	1.30%	3.40%
NY	1.20%	3.20%
RFC	1.60%	3.40%
Entergy	0.90%	2.60%
Gateway	1.20%	3.10%
Southern	0.80%	2.40%
TVA	0.90%	2.60%
VACAR	1.00%	2.80%
SPP North	1.20%	3.20%
SPP South	0.80%	2.30%
AZNMSNV	1.40%	2.70%
CA	0.90%	2.50%
NWPP	1.40%	3.00%
RMPA	0.00%	2.50%
Average	**1.20%**	**2.90%**

Source: EPRI and DOE

New Build Financing Assumptions

Inputs	Renewable Generation Technologies with Loan Guarantees	Renewable Generation Technologies without Loan Guarantees	Coal - Pulverized Coal and IGCC	Coal - IGCC with Carbon Capture	Nuclear	Advanced Combustion Turbine	Advanced Combined Cycle
Book Life (yrs)	20	20	40	40	40	30	30
Debt Life (yrs)	20	20	20	20	20	15	20
MACRS Depreciation Schedule (yrs)	7	7	20	20	15	15	20
After Tax Nominal Equity Rate (%)	10.75%	12.75%	15.75%	12.75%	12.75%	12.75%	12.75%
Equity Ratio (%)	50.0%	50.0%	42.5%	42.5%	42.5%	57.5%	50.0%
Pre-Tax Nominal Debt Rate (%)	5.13%	7.13%	10.13%	7.13%	7.13%	7.63%	7.13%
Debt Ratio (%)	50.0%	50.0%	57.5%	57.5%	57.5%	42.5%	50.0%
Income Tax Rate (%)	39.30%	39.30%	39.30%	39.30%	39.30%	39.30%	39.30%
Other taxes/insurance (%)	1.17%	1.17%	1.17%	1.17%	1.17%	1.17%	1.17%
Inflation (%)	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%
Outputs							
Levelized Real Fixed Capital Charge Rate (%)	10.70%	12.20%	14.20%	11.20%	10.80%	12.90%	12.20%
Real WACC (%)	4.60%	6.10%	7.80%	5.50%	5.50%	6.90%	6.10%

Notes:

1. Renewable Generation Technologies with Loan Guarantee assumptions are consistent with AEO 2010 (new renewables online by 2015 get a 2 percentage point reduction in cost of debt and cost of equity).
2. Coal - Pulverized Coal and IGCC assumptions are consistent with AEO 2010 (new coal without carbon capture gets a 3 percentage point adder to cost of debt and cost of equity).

Source: EPA v4.10

Retrofit Financing Assumptions

Inputs	Utility Retrofit Financing	Merchant Retrofit Financing
Book Life (yrs)	20	20
Debt Life (yrs)	20	20
MACRS Depreciation Schedule (yrs)	20	20
After Tax Nominal Equity Rate (%)	10.30%	17.28%
Equity Ratio (%)	45.0%	55.0%
Pre-Tax Nominal Debt Rate (%)	6.25%	8.94%
Debt Ratio (%)	55.0%	45.0%
Income Tax Rate (%)	39.30%	39.30%
Other taxes/insurance (%)	1.17%	1.17%
Inflation (%)	2.25%	2.25%
Outputs		
Levelized Real Fixed Capital Charge Rate (%)	11.16%	17.50%
Real WACC (%)	4.37%	9.49%

Notes:

1. Regulated Environmental Retrofits Financial Assumptions are from EPA v4.10 with a 20-year book life rather than a 30-year book life
2. Merchant Environmental Retrofits assume EIA's AEO2009 merchant debt/equity ratios and ROE, while the cost of debt is from Bank of America's US High Yield Utility Index.

Source: EPA v4.10 and EEI.

Nuclear Build Limits

- Provided by NEI
- Hard-wired units (5,500 MW)
- Candidate units (4,300 MW) – allowed to be built on or after specified date, but only if deemed economic
- Economic units – including 8 units above, up to 45 units by 2030 on national basis, regional limits based on existing brownfield sites.

Appendix B: CASE DESCRIPTIONS

Case Name	Description
Reference Case (See Run 1)	**"On the books" regulation currently in place:** • Clean Air Interstate Rule (CAIR) for NO_X and SO_2 as promulgated for both Phases I and 2. • State-specific mercury regulation applied for CT, CO, DE, GA, IL, MA, MD, ME, MI, MN, MT,NC, NH, NJ,NM, NY, OR, WA and WI. • BART is included for all BART-affected units not included in the CAIR region for $SO_2$and NO_X. • The Western Regional Air Partnership (WRAP) is modeled. • All existing state regulations for NO_X, SO_2, Hg and CO_2 are included.[1] • All final NSR consent decrees requiring controls and/or allowance retirements are modeled as per EPA IPM 4.10.[1] • State renewable portfolio standards modeled (only covers mandatory programs, not state voluntary targets or goals). [1]

1. For documentation of state air rules, NSR consent decrees and renewable portfolio standards, see Chapter 3 of EPA's Documentation for EPA Base Case v 4.10, Using the Integrated Planning Model, available online at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html.

<table>
<tr><th>Case Name</th><th>Description</th></tr>
<tr><td>Air Base Case – Command and Control</td><td>MACT Compliance
Compliance is required for mercury and all non-mercury HAPS across the entire U.S.
All coal units required to install a scrubber (wet or dry), activated carbon injection (ACI) and a baghouse/fabric filter. Oil/gas steam units that burn oil only have to install an electrostatic precipitator (ESP).
Oil gas steam units that are dual-fuel capable are assumed to switch to gas to comply.
Compliance is required by 2015 to satisfy the timeline set by the Court-approved HAPs MACT Consent Decree.
SO_2 Compliance
No additional SO_2 controls are required beyond the scrubber requirement detailed above.
NO_X Controls for Ozone and Particulate NAAQS Compliance
Eastern U.S.
To be modeled as a cap-and-trade system for NO_X utilizing the preferred option as proposed in EPA's Clean Air Transport Rule through 2017. Unlimited intra-state trading is allowed, while interstate trading is limited to EPA's proposed 3-year variability limits (approximately 6% for most states).
Starting in 2018, all coal units in the Eastern U.S. are required to install SCRs in order to be deemed "well controlled" for NO_X. The requirement for additional NO_X controls is driven by a combination of factors, including an expected tightening of NO_X budgets under the unknown requirements of Transport Rule 2 (TR 2), expected further tightening of the NAAQS for ozone, and state-specific SIP planning requirements that are expected to target uncontrolled NO_X sources. The geographical scope of TR 2, and therefore the requirement for SCRs, is assumed to be identical to TR 1.
Western U.S.
To simulate the economic screening that is part of the Best Available Retrofit Technology (BART) analysis that is the major driver impacting NO_X controls for Western units, it is assumed that SCRs are installed on all units where the cost to control NO_X is $5,000/ton removed or less starting in 2018. Prior to 2018, only announced and committed SCRs as a result of completed BART determinations are required.</td></tr>
</table>

<table>
<tr><th>Case Name</th><th>Description</th></tr>
<tr><td>Alternate Air Case – Market-based Flexibility</td><td>For MACT Compliance (covers mercury and all non-mercury HAPS)
Similar to Air Case 1, but the requirement for a scrubber is relaxed to allow units 200 MW or less to install dry sorbent injection (DSI) technology if it is deemed to be the more economical solution. This scenario still requires a baghouse/fabric filter. A separate requirement for ACI is not required in this scenario since the technical literature already combines the cost of ACI injection with the cost of DSI (hydrated lime injection for HAPs control).
DSI utilizing trona, sodium bicarbonate, or hydrated lime is starting to prove feasible in some installations for controlling non-mercury HAPS. While testing continues, and DSI technology has not proven to be effective control technology for non-mercury HAPs for all boiler and fuel combinations, DSI technology may provide a cost-effective alternative for some small units that would otherwise shutdown if forced to install a scrubber.
SO_2 Compliance
Same as Air Base Case.
NO_X Controls for Ozone and Particulate NAAQS Compliance
Eastern U.S.
Same as Air Base Case through 2017.
Beginning in 2018, it is assumed that unlimited intra-state trading continues, interstate trading continues to be limited to EPA's proposed 3-year variability limits (approximately 6% for most states), and the geographical scope of TR 2 is identical to the geographic scope in TR 1. However, the cap on emissions is reduced to approximate the NO_X caps contemplated by Sen. Carper's proposed legislation. To reconcile the difference between the zones in Carper's proposal and the TR 1 region, the effective NOx emissions rate under Carper's proposal is applied to the TR 1 region.
Western U.S.
Same as Air Base Case.</td></tr>
</table>

Case Name	Description

Ash Base Case – Treatment Under Subtitle D as Nonhazardous	• All units with wet fly ash disposal and/or wet bottom ash disposal are required to convert to dry handling, and install a landfill and wastewater treatment facility.[1] Cost components are as follows:
	
	• **Capital Costs**[2]
	  • Conversion to dry fly ash handling – Average $23 million per unit.
	  • Conversion to dry bottom ash handling – Average $20 million per unit.
	  • Cost to install new wastewater treatment capability as follows:
	    • For units without scrubbers – Average $80 million per facility
	    • For units with scrubbers – Average $200 million per facility
	  • The cost to convert for dry handling of FGD solids is an average of $35 million per facility.
	
	• **O&M Costs**[2]
	  • Variable O&M: Increased operating costs associated with dry handling - $2.00 per ton.
	  • Fixed O&M:
	    • For units without scrubbers -- $3 million annual increase per facility
	    • For units with scrubbers - $4.5 million annual increase per facility
	
	• **Retrofit Timing**
	  • Assume the final rule promulgation occurs in 2012. Under Subtitle D, plants will have 5 years (2017) to stop using active ponds and 7 years (2019) to close all ponds.

1. Costs applied to units with ponds for fly ash and/or bottom ash based on EIA-923 Schedule 8A, 2008.
2. EOP Group for USWAG, “Cost Estimates for the Mandatory Closure of Surface Impoundments Used for the Management of Coal Combustion Byproducts at Coal-Fired Electric Utilities,” November 11, 2009.

Case Name	Description
Alternate Ash Case – Treatment Under Subtitle C as Hazardous[1]	• As proposed, EPA's first approach would be to regulate disposal of coal combustions residuals (CCRs) under RCRA Subtitle C by creating a Special Waste category under a new Subpart S. CCRs destined for disposal would be a listed Special Waste. These CCRs would be regulated under Subtitle C from the point of generation to disposal, and would be subject to the same requirements as those for hazardous waste, including provisions for corrective action and financial responsibility. • Under this scenario the incremental additional costs to meet the added requirements associated with Subtitle C regulation need to be added to the base costs for Subtitle D regulation. See the example below.[2,3] • Under Subtitle C, states are expected to adopt the rules within 2 years, so plants will have until 2019 to stop using ponds and until 2021 to close all ponds.

1. The modeled costs of Subtitle C (hazardous waste) regulation do not reflect the potential full costs of hazardous waste regulation of CCBs.

   Since the substantive standards for disposal facilities are essentially the same under both the Subtitle D and Subtitle C option (e.g., liners, groundwater monitoring, capping), disposal costs should also be roughly the same. While EPA assumes under the Subtitle C Option that current disposal practices will continue – that existing disposal facilities will be re-permitted as hazardous waste disposal facilities – we do not expect that to be the case. It is unlikely that an adequate number of on-site, utility-operated Subtitle C disposal facilities will exist due to a variety of factors, including, siting restrictions, zoning restrictions, state and or local ordinances, lack of available land, and public opposition to the siting/permitting/operation of hazardous waste disposal facilities. As a result, some utilities will have to rely on commercial Subtitle C disposal facilities; based on interviews with utilities, as much as 12%, or 15–20 million tons of coal combustion byproducts, will have to be sent to such facilities. This volume would exhaust the existing commercial Subtitle C disposal capacity of 34 million tons within two years. We have not estimated the commercial Subtitle C disposal costs, which would vary between disposal facilities based on the hazardous waste disposal market. Even if we were to estimate such costs, they would not be valid after two years, when existing commercial disposal capacity is exhausted.

   Another cost that is not considered in the model is that of corrective action associated with Subtitle C option. Obtaining a Subtitle C disposal permit would trigger facility-wide corrective action, requiring an assessment of *all* CCB disposal units at a power plant, both existing and closed units. We have not included an estimate of corrective action costs because they are essentially unknowable until a site assessment can be conducted.
2. EPRI, "Engineering and Cost Assessment of Listed Special Waste Designation of Coal Combustion Residuals Under Subtitle C of the Resource Conservation and Recovery Act" November 11, 2010.
3. EPRI, "Cost Analysis of Proposed National Regulation of Coal Combustion Residuals from the Electric Generating Industry," November 11, 2010.

Example

Capital costs for a facility with 2 - 800 MW units impacted by the ash rule

Component	Non- or Dry FGD System	Wet FGD System
Subtitle D Costs		
Fly ash conversion	$46 MM	$46MM
Bottom ash conversion	$40 MM	$40 MM
FGD solids	-0-	$35 MM
Wastewater treatment facility	$80 MM	$200 MM
Subtotal if only Subtitle D Treatment	$166 MM	$ 321 MM
Incremental cost for treatment as hazardous under Subtitle C[1]	$70 MM	$70 MM
Total if Subpart C Treatment	**$236 MM**	**$391 MM**

1. Incremental costs vary depending on numerous factors including whether the plant has an existing ESP enclosure, gypsum containment building and utilizes FGD. For a unit consisting of 2 800-MW units, costs can range from $50 – 90 million, or $70 million on average.

Case Name	Description
Base Water Case 316(b)	• All fossil and nuclear facilities that have at least one once-through cooling unit and would have been classified as a Phase II Facility under the remanded Phase II rule are required to install cooling towers. This does not apply to facilities that are completely closed-cycle cooling even if they use more than 50 million gallons per day. However, it does include some facilities that use helper towers to cool the thermal discharge during portions of the year. • EPRI, in a soon to be released technical report, has identified approximately 400 facilities that are impacted by the rule. • EPRI does not disclose costs for individual facilities or units. • EPRI does provide cost estimates for four categories of fossil retrofits (from "easy" to "more difficult") and three categories of nuclear retrofit (from "less difficult" to "intermediate"), and provides a percentage of units that fall into each of the categories. • EEI used this data to calculate a weighted average price for fossil retrofits and a weighted average price for nuclear retrofits. EEI converted those average cost value stated in $/gallon per minute (GPM) to an average value stated in $/kWh to be applied in IPM. See the assumptions section for additional detail. The price assumption does not include the cost for intake screens. • While the final outcome of EPA's rulemaking on 316(b) is not known at this time, based on evaluation of possible outcomes, EEI has chosen to follow the direction of a California policy on cooling water, whereby fossil units were allowed 10 years from the date of promulgation of a final rule to achieve compliance. Nuclear units were allowed at least 15 years or to their current license expiration. To emulate this timeline, EEI has assumed compliance no later than 2022 for fossil units and no later than 2027 for nuclear units. • For this case, EEI has chosen for its modeling that cooling towers will be required in all applications.[1]

1. EPA may ultimately promulgate a rule that allows for flexibility in the definition of Best Technology Available (BTA) that may not require cooling towers for every application. In a December 16, 2010, letter to Congressman Fred Upton, EPA Administrator Lisa Jackson indicated that she does "not favor a one-size-fits-all federal mandate. The proposal that EPA issues next March [for 316(b)] will reflect a common-sense approach that reasonably accommodates site specific circumstances while keeping faith with the need to minimize adverse environmental impact."

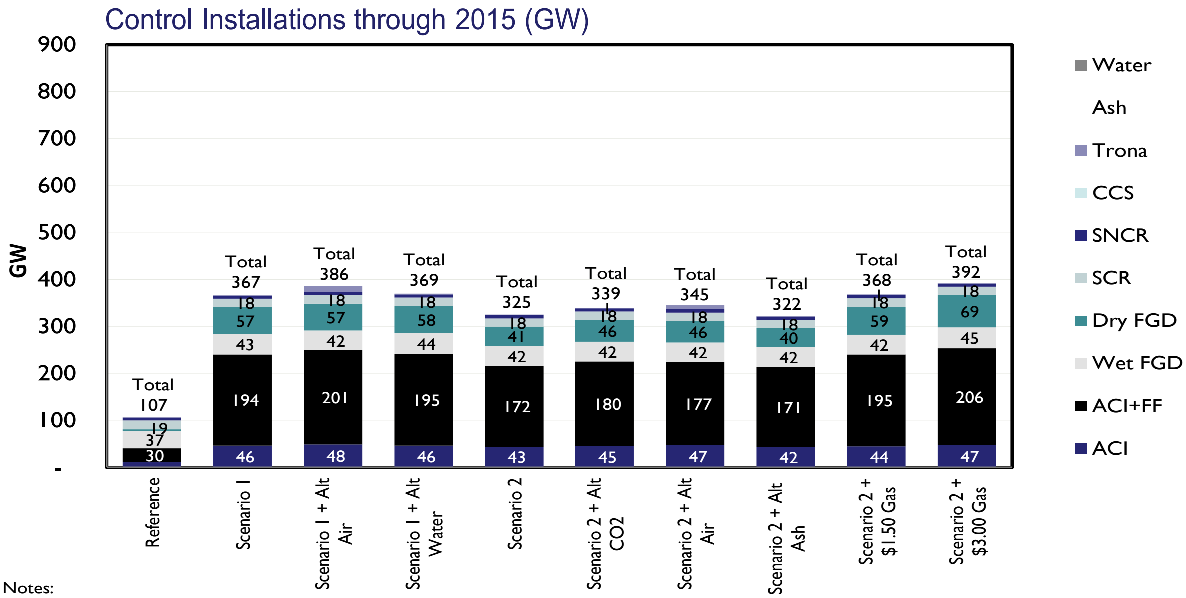
Case Name	Description
Alternate Water Case 316(b)	• In the Alternate Water case, instead of requiring cooling towers at every impacted facility, assumes that only units on sensitive water bodies (oceans, estuaries and tidal rivers) and with design intake flows of 125 million gallons per day and above are impacted by the requirement to install cooling towers. • The Alternate Water case affects 85 GW of generation capacity, which is a total of 92 units. For comparison, the Base Water case affects 314 GWs of generation, which is a total of 400 units. • In addition, while it was noted that under the Alternate Water case units that no longer needed to install cooling towers would likely be impacted by costs to improve their intakes (e.g., improved screens or other modifications), there is not a reliable source of data on these potential costs impacts. Therefore, these costs have not been included in the Alternate Water case. • Compliance deadlines are identical to the deadlines in the Base Water Case.

Case Name	Description
CO_2 Policy	• The exact impact of CO_2 regulation or legislation is uncertain. We do not know if Congress will ultimately pass a cap-and-trade bill, a carbon tax or a performance standard; nor do we know any specifics, such as, if Congress elected a cap-and-trade program, would it allocate allowances at no cost, auction allowances or set an alternate structure. • Yet, regardless of the exact regulatory or legislative outcome, there is consensus that utilities will be faced with a cost for greenhouse gas emissions whether through regulation or legislation. • To respond to this expectation, EEI member companies routinely perform sensitivity analysis as a part of their planning regimes that includes investigating the potential impact of a future carbon constraint. • This policy case serves as a proxy for regulatory action by EPA and/or potential future legislation from Congress. The EEI Generation Fleet Modeling Group estimates that one proxy for a future CO_2 constraint would be a \$25 price on each ton of CO_2 emitted on all facilities starting in 2017. Price escalates at 5% per year (real). It is roughly modeled on the Administration's commitment to achieve a 17% reduction from 2005 levels by 2020, but it is not necessarily intended to meet that level of reduction. • In addition, to meet anticipated CO_2 standards for new facilities, new coal-fired generation is to achieve 90% CO_2 capture through Carbon Capture and Storage (CCS) starting in 2020. • A lower load forecast was used in the CO_2 scenarios to be consistent with EPA's modeling of CO_2 policy under the American Power Act. In the EEI modeling, the load and peak demand forecasts were adjusted downward starting in 2017 with the assumed start of the CO_2 program. The lower peak and demand forecasts are a result of both price elasticity due to customer response to higher electricity prices and the energy efficiency programs mandated under that proposed legislation.

Case Name	Description
Alternate CO_2 Policy	• Same as base CO_2 Policy except the price starts at \$10 per ton in 2017, escalating at 5% (real).

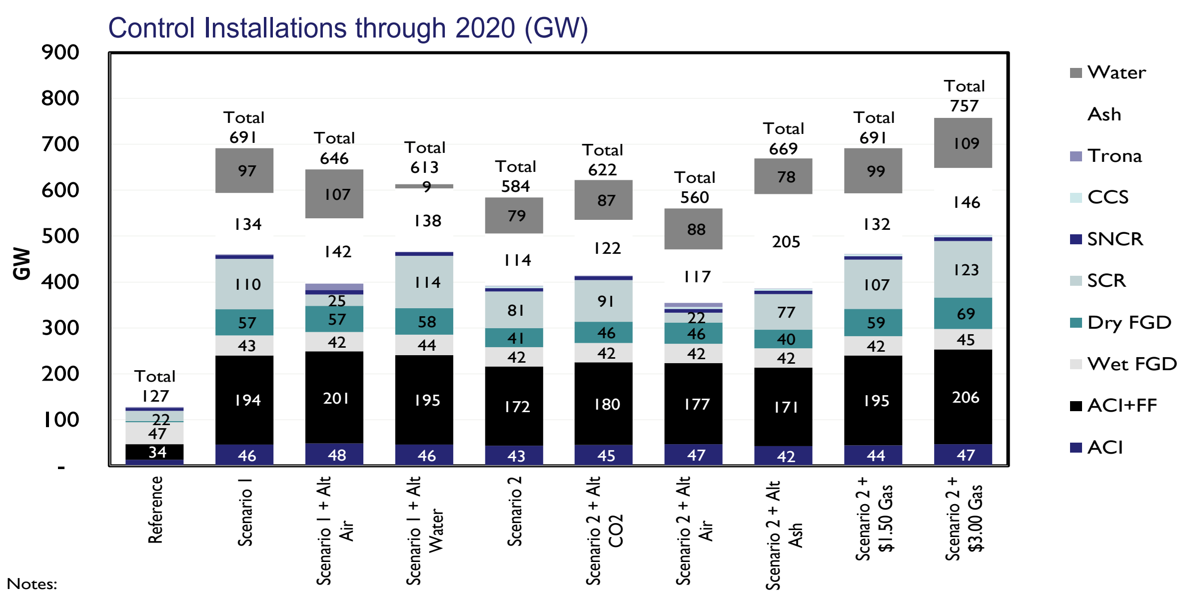
Appendix C: RESULTS DATA AND CHARTS

National Pollution Control Installations Summary: (Firm + Economic) – Through 2015



Notes:
1. Units may install more than one control and their capacity will be reported separately for each control.
2. Unlabeled control installation segments are 7 GW or less each.

National Pollution Control Installations Summary: (Firm + Economic) – Through 2020



Notes:
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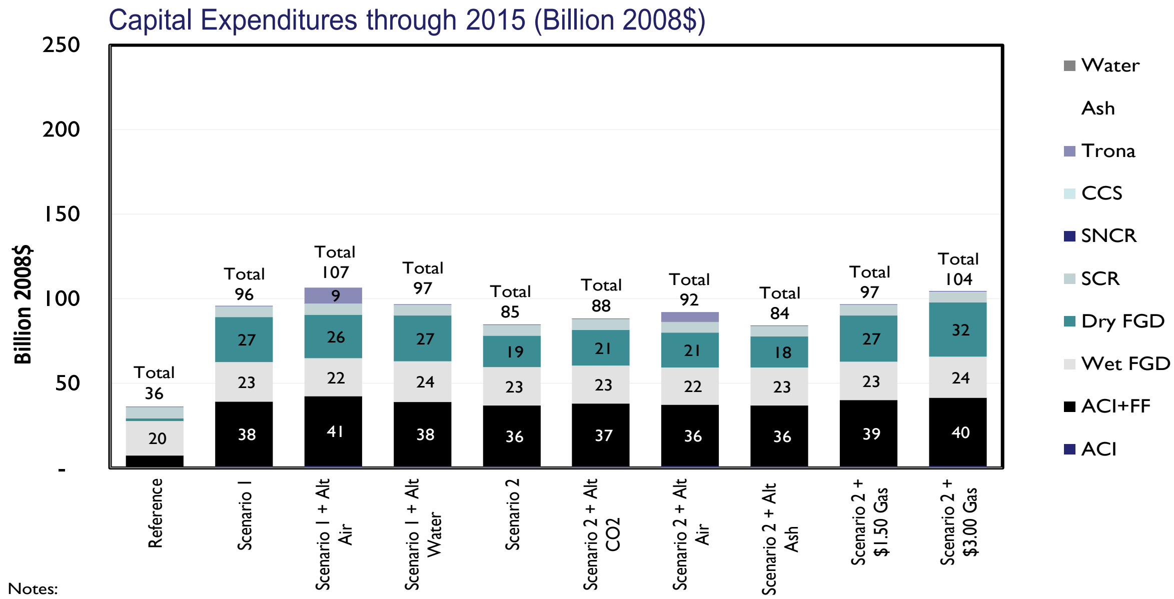
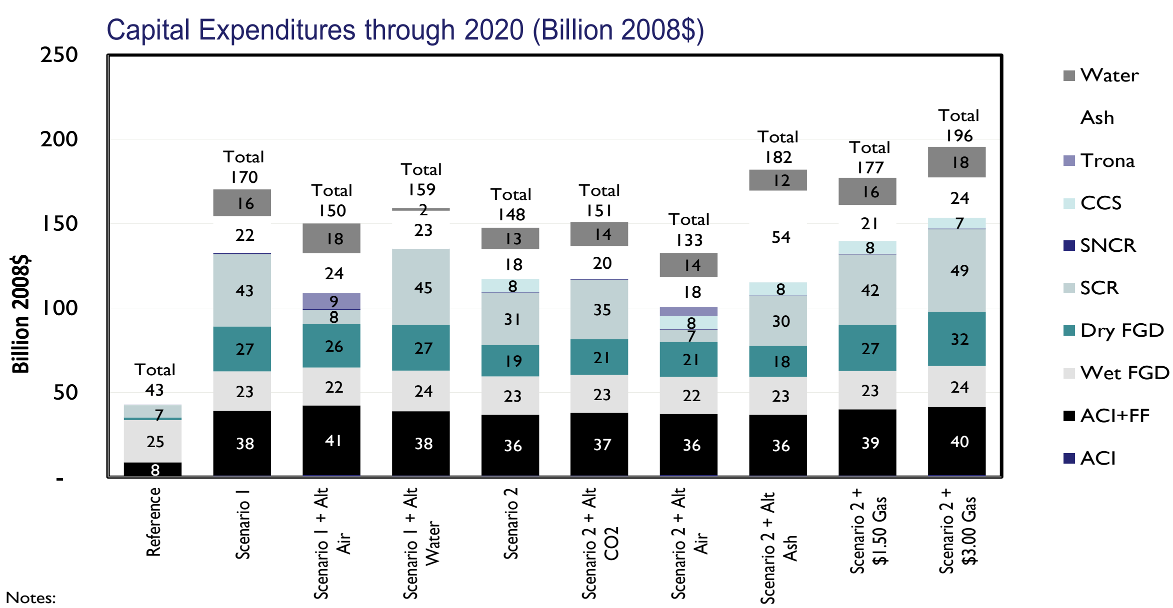
National Pollution Control Installations Summary: (Firm + Economic) – Through 2015



Notes:
1. Capital Expenditures include total overnight costs and AFUDC/IDC.
2. Unlabeled control installation segments are $7 billion or less each.

National Pollution Control Installations Summary: (Firm + Economic) – Through 2020



Notes:
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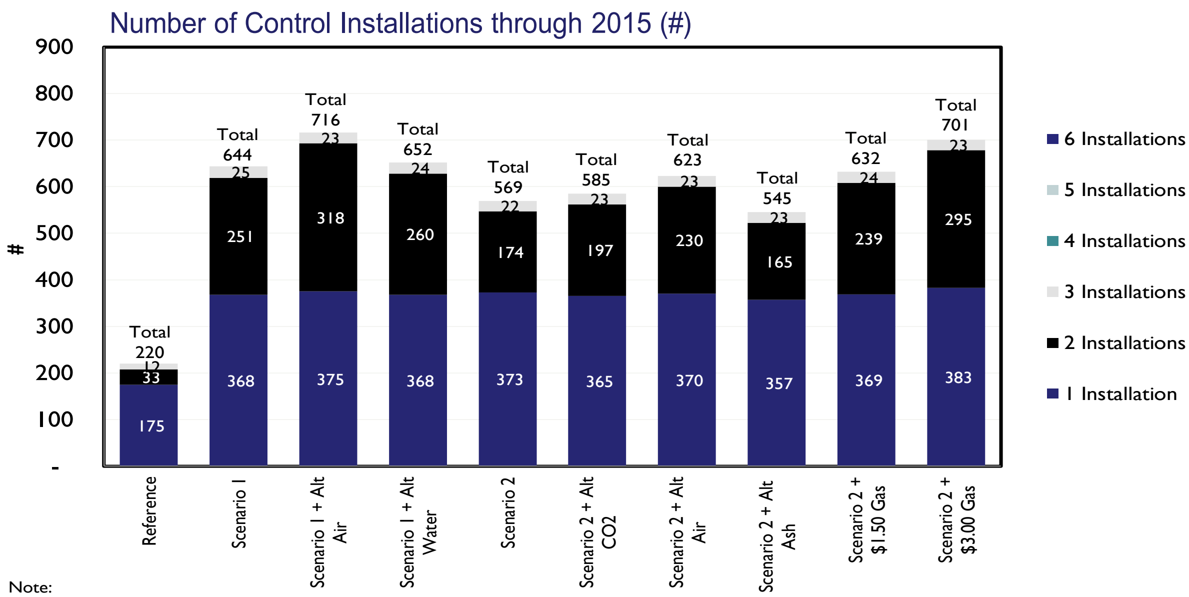
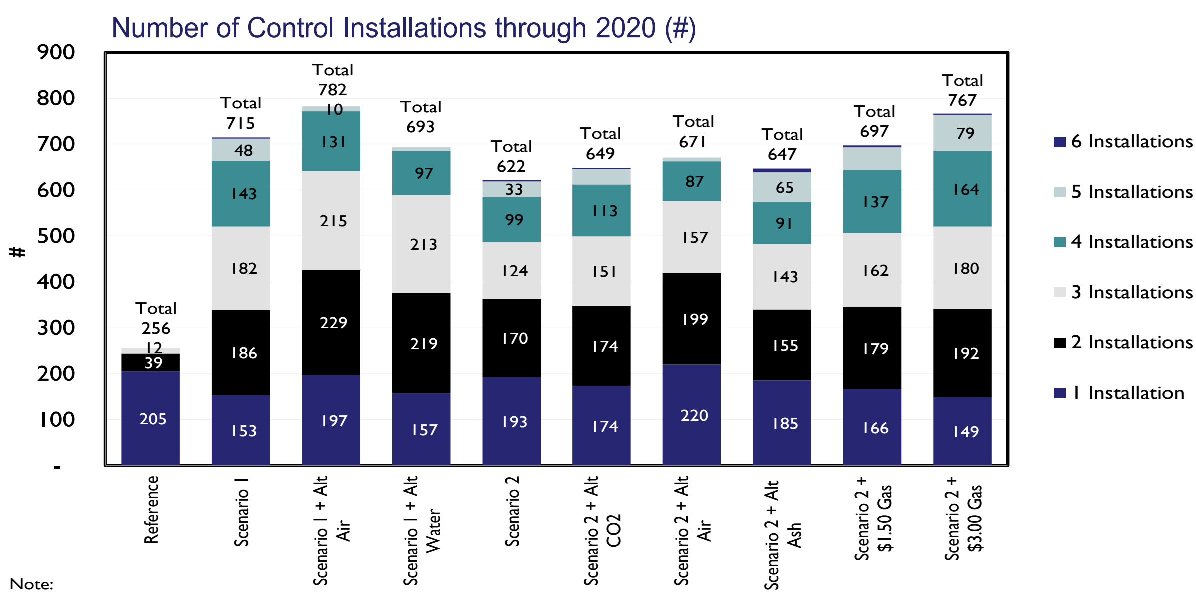
2. Unlabeled control installation segments are $7 billion or less each.

National Pollution Control Installations Summary: (Firm + Economic) – Through 2015



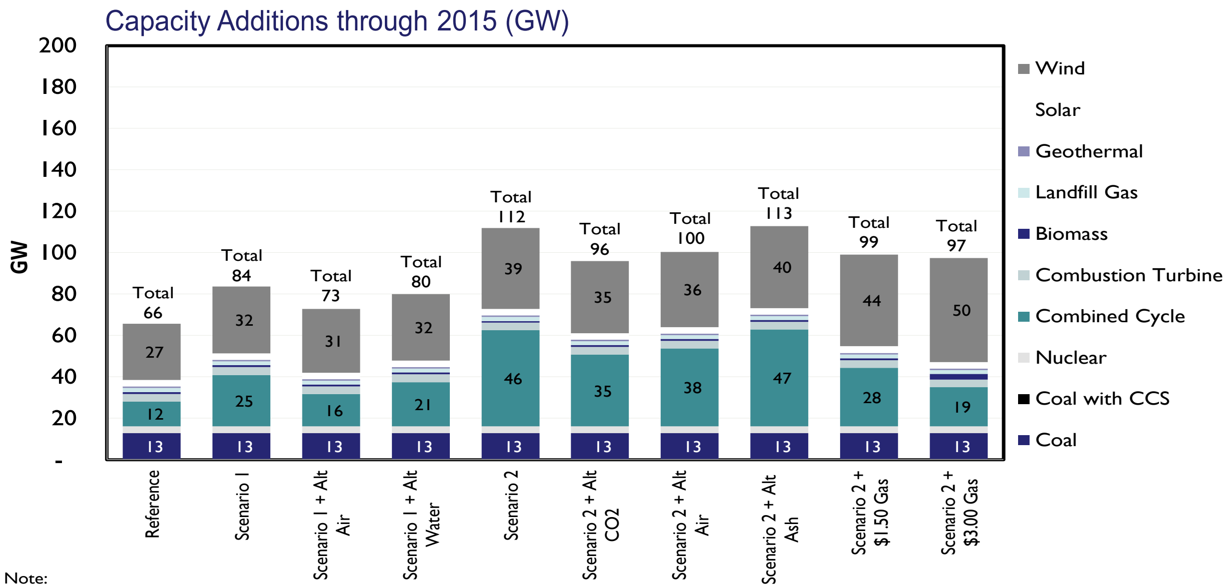
Note:
1. Total number of existing and firm coal units = 1,259
2. Unlabeled control installation segments are 10 units or less each.

National Pollution Control Installations Summary: (Firm + Economic) – Through 2020



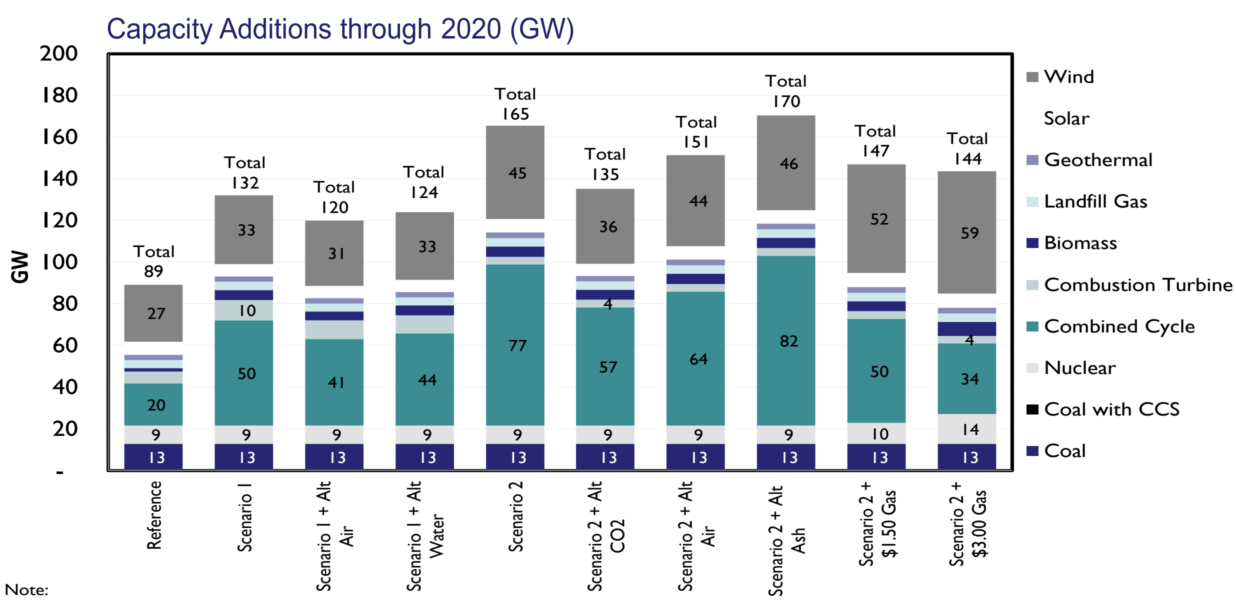
Note:
1. Total number of existing and firm coal units = 1,259
2. Unlabeled control installation segments are 10 units or less each.

National Capacity Additions: (Firm + Economic) – Through 2015



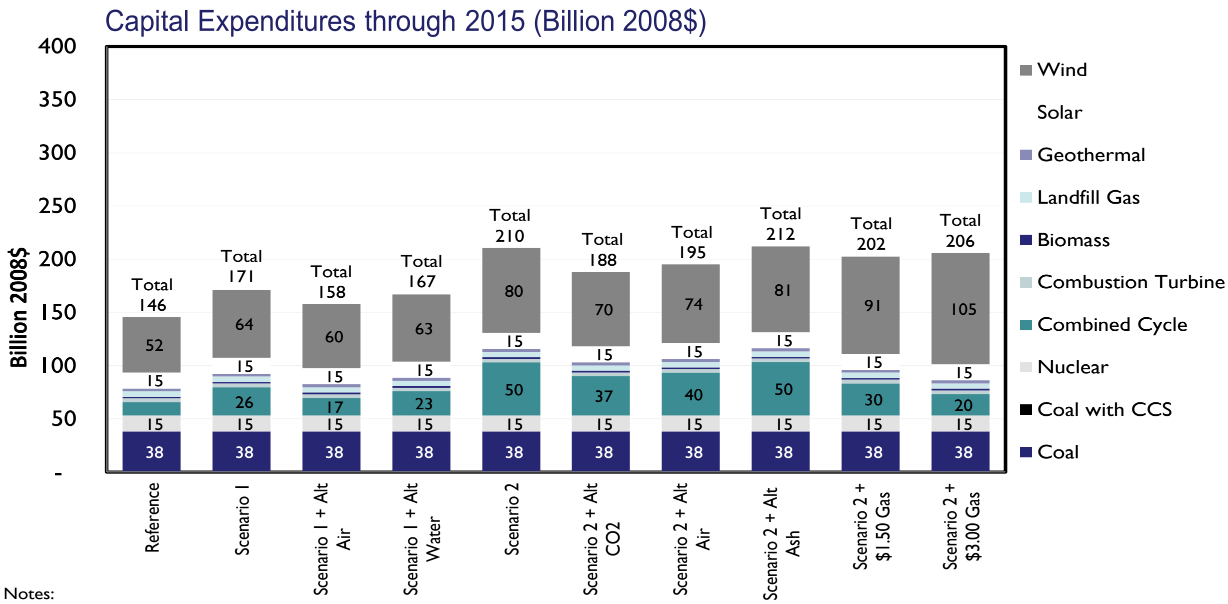
Note:
1. Unlabeled additions segments are 7 GW or less each.

National Capacity Additions: (Firm + Economic) – Through 2020



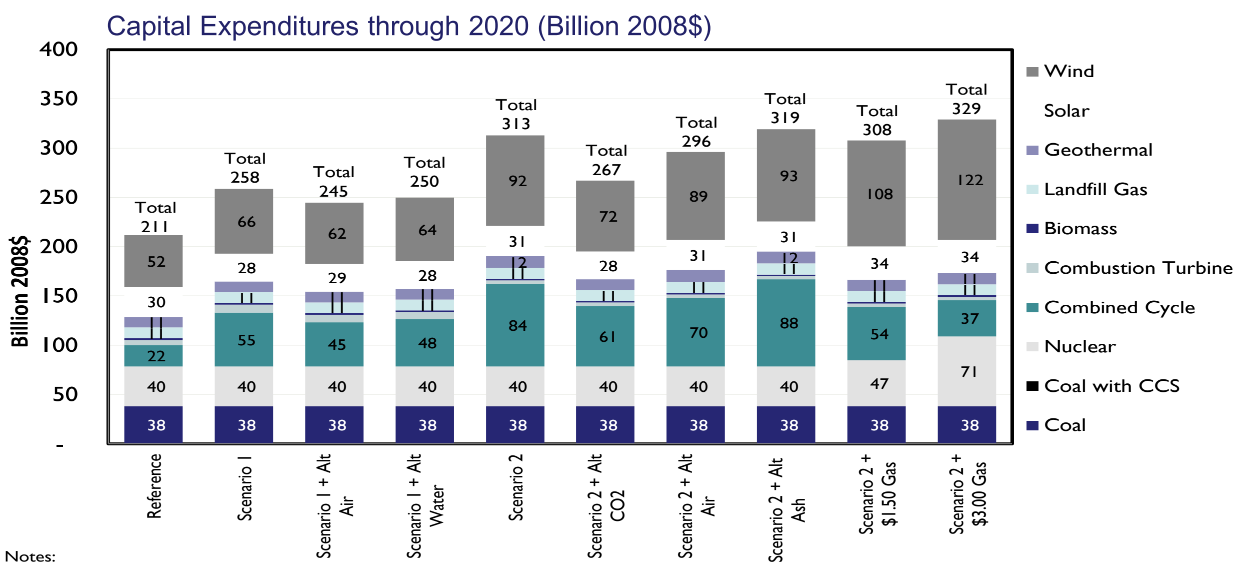
Note:
1. Unlabeled additions segments are 7 GW or less each.

National New Capacity Capital Expenditures: (Firm + Economic) – Through 2015



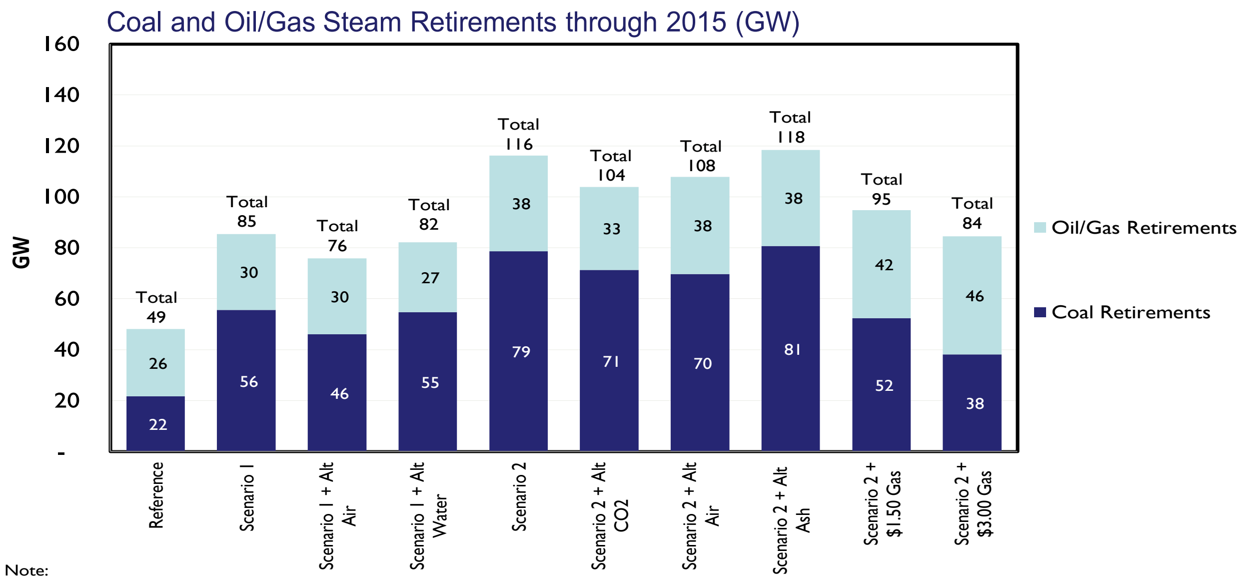
Notes:
1. Capital Expenditures include total overnight costs and AFUDC/IDC.
2. Unlabeled control installation segments are $7 billion or less each.
3. Capital Expenditures for renewable builds are decremented consistent with EPA's treatment of the PTC and ITC.

National New Capacity Capital Expenditures: (Firm + Economic) – Through 2020



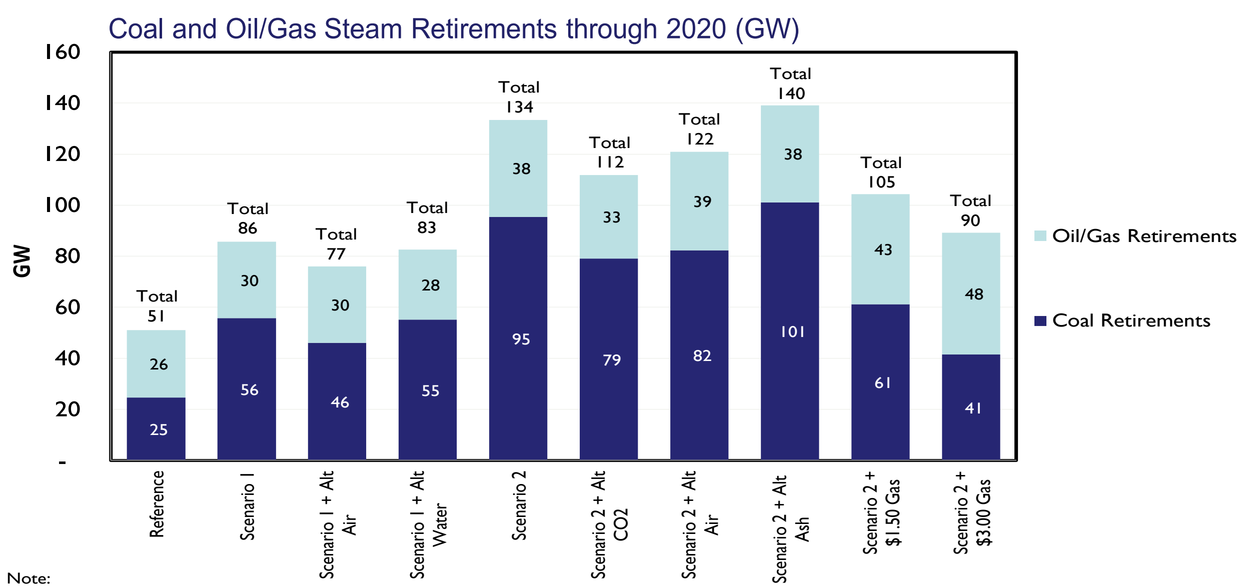
Notes:
1. Capital Expenditures include total overnight costs and AFUDC/IDC.
2. Unlabeled control installation segments are $10 billion or less each.
3. Capital Expenditures for renewable builds are decremented consistent with EPA's treatment of the PTC and ITC.

National Retirements: (Firm + Economic) – Through 2015



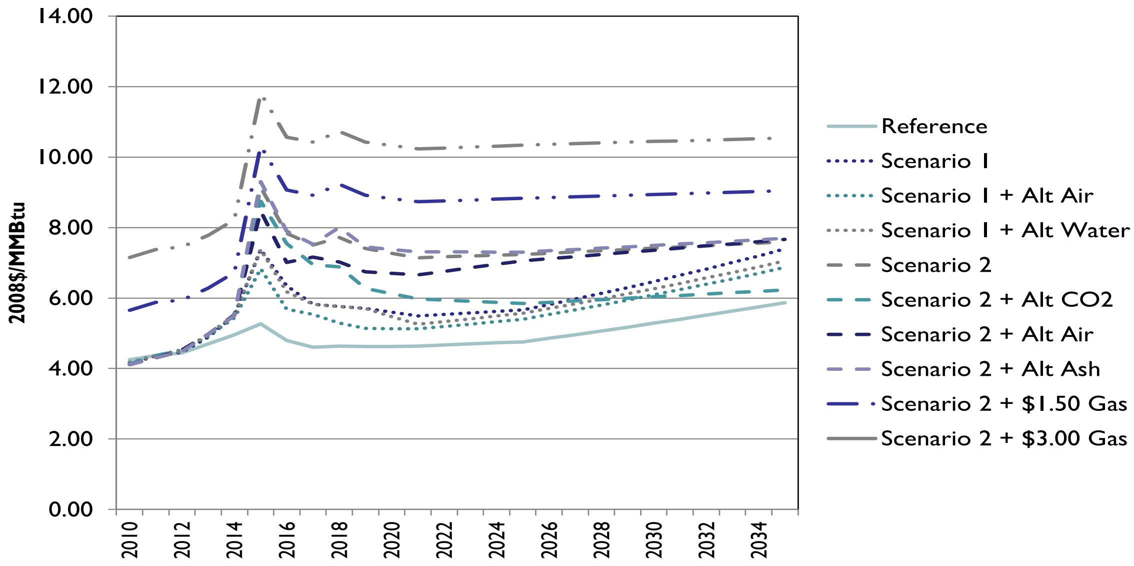
Note:
1. Nuclear retirements are less than 2 GW in all cases through 2015 and are not shown here.

National Retirements: (Firm + Economic) – Through 2020

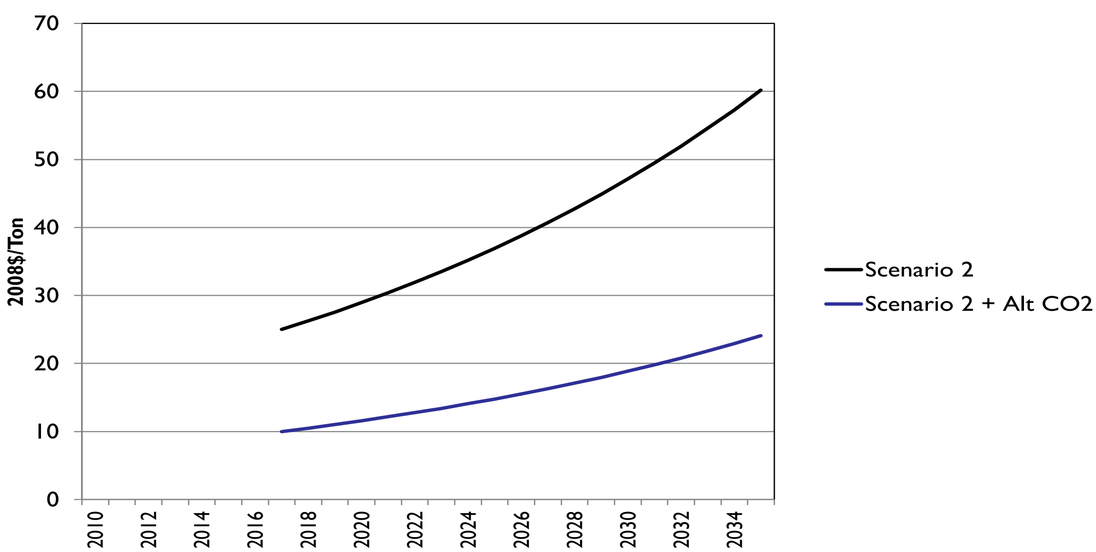


Note:
1. Nuclear retirements are less than 2 GW in all cases through 2020 and are not shown here.

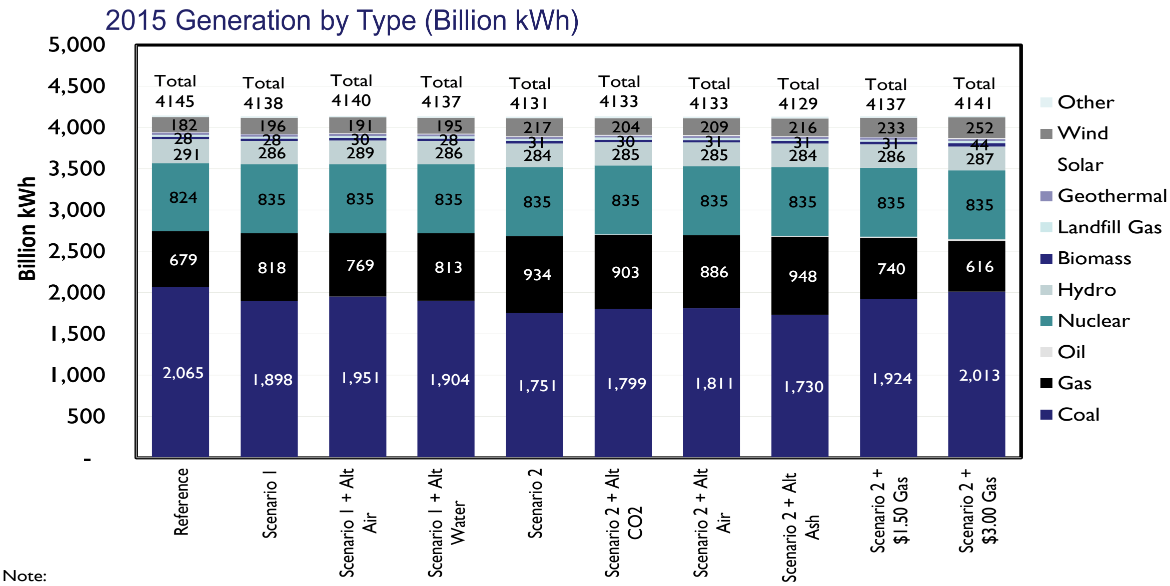
Henry Hub Natural Gas Prices



CO_2 Prices

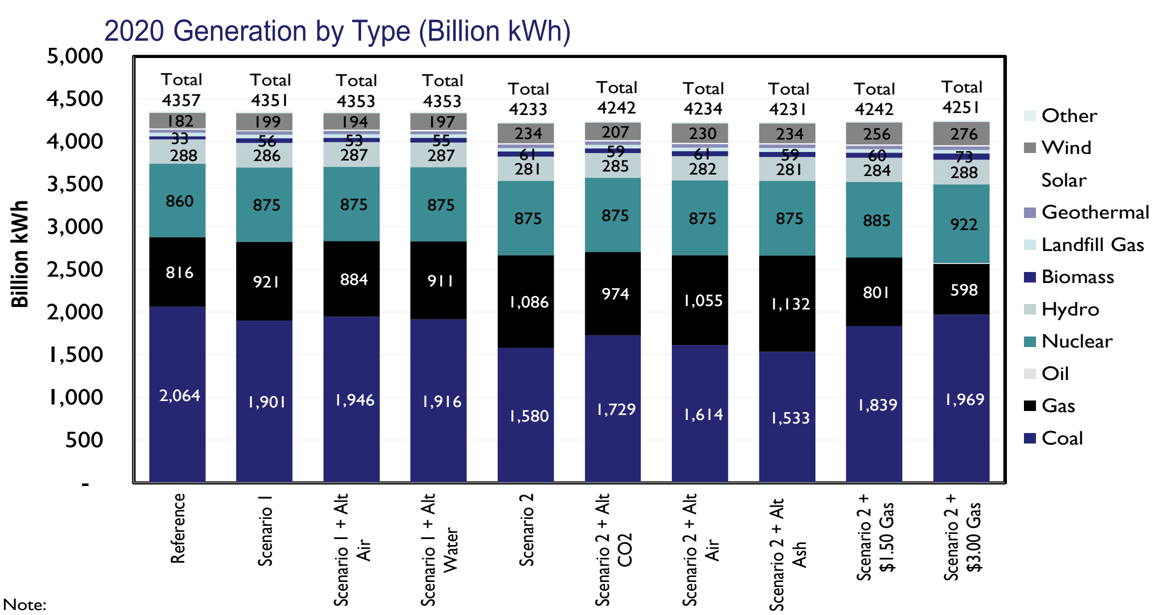


2015 Generation by Type



Note:
1. Unlabeled generation segments are 20 billion kWh or less each.

2020 Generation by Type



Note:
1. Unlabeled generation segments are 20 billion kWh or less each.

Regional Results - Coal Retirements

Run	Scenario	2015 Planned Coal Retirements (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1-10	All Cases	0.1	3.3	1.9	0.0	0.0	0.0	0.0	0.2	5.5

Run	Scenario	2015 Unplanned Coal Retirements (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	1.2	5.4	3.1	0.0	0.0	0.0	3.6	2.9	16.1
2	Scenario 1	1.4	16.0	20.7	0.9	2.3	1.4	5.9	1.3	50.0
3	Scenario 1 + Alt Air	1.3	12.4	14.9	0.9	1.7	1.3	5.3	2.8	40.5
4	Scenario 1 + Alt Water	1.4	14.9	19.5	0.9	2.3	1.5	6.6	2.0	49.2
5	Scenario 2	1.6	21.0	31.2	0.9	2.2	3.8	8.9	3.6	73.1
6	Scenario 2 + Alt CO2	2.0	18.4	28.2	0.9	3.0	2.3	7.5	3.5	65.7
7	Scenario 2 + Alt Air	1.3	16.6	28.2	1.3	1.2	2.7	7.8	5.1	64.1
8	Scenario 2 + Alt Ash	1.7	22.0	30.4	0.9	2.6	3.8	9.6	4.3	75.2
9	Scenario 2 + $1.50 Gas	0.4	13.8	20.0	0.9	0.0	2.7	7.8	1.2	46.8
10	Scenario 2 + $3.00 Gas	0.0	11.0	11.2	0.9	0.0	1.6	7.4	0.6	32.6

Run	Scenario	2020 Unplanned Coal Retirements (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	1.2	5.4	4.7	0.9	0.0	0.0	3.7	3.2	19.1
2	Scenario 1	1.4	16.2	20.7	0.9	2.3	1.4	5.9	1.3	50.2
3	Scenario 1 + Alt Air	1.3	12.4	14.9	0.9	1.7	1.3	5.3	2.8	40.5
4	Scenario 1 + Alt Water	1.4	15.0	19.7	0.9	2.3	1.5	6.6	2.0	49.6
5	Scenario 2	1.6	23.7	37.8	1.2	3.7	5.2	9.9	6.9	89.9
6	Scenario 2 + Alt CO2	2.0	19.3	31.0	1.2	4.0	3.0	8.3	4.6	73.5
7	Scenario 2 + Alt Air	1.3	17.2	33.5	1.9	1.2	3.4	8.8	9.6	76.7
8	Scenario 2 + Alt Ash	1.8	25.4	38.9	1.3	4.1	5.5	10.5	8.1	95.5
9	Scenario 2 + $1.50 Gas	0.4	14.5	23.2	1.2	0.4	3.4	8.7	3.7	55.6
10	Scenario 2 + $3.00 Gas	0.0	11.7	12.6	0.9	0.0	1.7	8.3	0.7	35.9

Run	Scenario	2015 Total Coal Retirements (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	1.3	8.6	5.0	0.0	0.0	0.0	3.6	3.1	21.6
2	Scenario 1	1.5	19.3	22.6	0.9	2.3	1.4	6.0	1.5	55.6
3	Scenario 1 + Alt Air	1.5	15.6	16.7	0.9	1.7	1.3	5.4	3.0	46.0
4	Scenario 1 + Alt Water	1.5	18.1	21.4	0.9	2.3	1.5	6.7	2.3	54.7
5	Scenario 2	1.7	24.2	33.1	0.9	2.2	3.8	9.0	3.8	78.6
6	Scenario 2 + Alt CO2	2.1	21.6	30.1	0.9	3.0	2.3	7.6	3.7	71.2
7	Scenario 2 + Alt Air	1.4	19.9	30.1	1.3	1.2	2.7	7.9	5.3	69.6
8	Scenario 2 + Alt Ash	1.8	25.3	32.3	0.9	2.6	3.8	9.6	4.5	80.7
9	Scenario 2 + $1.50 Gas	0.5	17.1	21.8	0.9	0.0	2.7	7.8	1.5	52.3
10	Scenario 2 + $3.00 Gas	0.2	14.2	13.1	0.9	0.0	1.6	7.4	0.8	38.2

Run	Scenario	2020 Total Coal Retirements (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	1.3	8.6	6.6	0.9	0.0	0.0	3.8	3.4	24.6
2	Scenario 1	1.5	19.5	22.6	0.9	2.3	1.4	6.0	1.5	55.7
3	Scenario 1 + Alt Air	1.5	15.6	16.7	0.9	1.7	1.3	5.4	3.0	46.0
4	Scenario 1 + Alt Water	1.5	18.3	21.6	0.9	2.3	1.5	6.7	2.3	55.1
5	Scenario 2	1.7	26.9	39.6	1.2	3.7	5.2	9.9	7.1	95.4
6	Scenario 2 + Alt CO2	2.1	22.6	32.9	1.2	4.0	3.0	8.4	4.9	79.0
7	Scenario 2 + Alt Air	1.4	20.5	35.4	1.9	1.2	3.4	8.8	9.8	82.3
8	Scenario 2 + Alt Ash	1.9	28.6	40.8	1.3	4.1	5.5	10.5	8.3	101.1
9	Scenario 2 + $1.50 Gas	0.5	17.8	25.1	1.2	0.4	3.4	8.7	4.0	61.2
10	Scenario 2 + $3.00 Gas	0.2	14.9	14.5	0.9	0.0	1.7	8.4	1.0	41.4

Regional Results - Capacity Additions

Run	Scenario	2015 Planned Additions (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1-10	All Cases	2.8	5.2	10.3	1.9	4.3	2.8	2.2	5.7	35.3

Run	Scenario	2015 Unplanned Additions (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	5.3	4.0	2.0	0.2	0.1	0.0	5.9	12.9	30.4
2	Scenario 1	6.0	10.2	11.8	1.3	0.1	0.0	4.8	14.2	48.3
3	Scenario 1 + Alt Air	5.8	7.5	5.3	0.2	0.1	0.0	4.7	13.8	37.4
4	Scenario 1 + Alt Water	5.9	9.1	9.8	0.7	0.1	0.0	4.9	14.1	44.6
5	Scenario 2	7.9	16.0	21.5	5.5	1.8	1.5	6.7	15.7	76.5
6	Scenario 2 + Alt CO2	6.8	12.4	16.8	3.7	0.6	0.0	5.6	14.8	60.6
7	Scenario 2 + Alt Air	7.3	11.2	18.5	5.9	1.0	0.6	5.6	15.0	65.1
8	Scenario 2 + Alt Ash	7.9	16.6	20.7	5.5	2.1	1.7	7.3	15.6	77.4
9	Scenario 2 + $1.50 Gas	7.9	10.9	14.1	4.6	1.9	2.0	5.6	16.6	63.7
10	Scenario 2 + $3.00 Gas	8.1	8.3	8.3	4.7	4.6	4.1	6.0	18.1	62.2

Run	Scenario	2020 Unplanned Additions (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	6.0	10.6	2.9	2.0	0.1	0.0	6.2	20.6	48.3
2	Scenario 1	8.2	23.1	20.0	7.4	4.0	1.0	5.2	22.2	91.1
3	Scenario 1 + Alt Air	8.1	19.3	13.7	6.4	3.5	1.1	5.1	22.0	79.1
4	Scenario 1 + Alt Water	8.0	20.9	17.3	6.7	3.0	0.0	5.3	22.0	83.1
5	Scenario 2	9.6	28.2	32.6	9.1	6.5	3.8	10.7	24.3	124.6
6	Scenario 2 + Alt CO2	8.2	21.6	23.2	7.3	4.6	1.5	5.9	21.9	94.2
7	Scenario 2 + Alt Air	8.9	21.5	28.0	9.8	4.3	2.2	10.7	25.1	110.3
8	Scenario 2 + Alt Ash	9.8	30.1	33.8	9.2	7.0	4.1	10.9	24.6	129.5
9	Scenario 2 + $1.50 Gas	9.7	21.1	21.0	9.3	6.2	3.5	10.4	24.8	106.0
10	Scenario 2 + $3.00 Gas	10.1	19.4	14.2	9.1	9.3	4.6	10.1	26.0	102.6

Run	Scenario	2015 Total Additions (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	8.1	9.2	12.3	2.2	4.4	2.8	8.1	18.6	65.7
2	Scenario 1	8.8	15.4	22.1	3.2	4.4	2.8	7.1	19.9	83.6
3	Scenario 1 + Alt Air	8.6	12.8	15.6	2.2	4.4	2.8	7.0	19.5	72.7
4	Scenario 1 + Alt Water	8.7	14.3	20.1	2.6	4.4	2.8	7.2	19.8	79.9
5	Scenario 2	10.7	21.2	31.8	7.5	6.0	4.3	9.0	21.4	111.8
6	Scenario 2 + Alt CO2	9.6	17.7	27.1	5.7	4.8	2.8	7.8	20.5	95.9
7	Scenario 2 + Alt Air	10.1	16.5	28.8	7.8	5.2	3.4	7.8	20.7	100.4
8	Scenario 2 + Alt Ash	10.7	21.9	31.0	7.5	6.4	4.5	9.5	21.3	112.7
9	Scenario 2 + $1.50 Gas	10.7	16.1	24.4	6.5	6.2	4.8	7.9	22.4	99.0
10	Scenario 2 + $3.00 Gas	10.8	13.5	18.6	6.7	8.9	6.9	8.3	23.8	97.4

Run	Scenario	2020 Total Additions (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	8.8	16.3	18.2	3.9	4.4	2.8	8.5	26.3	89.1
2	Scenario 1	11.0	28.9	35.3	9.3	8.2	3.9	7.4	27.9	132.0
3	Scenario 1 + Alt Air	10.8	25.0	29.0	8.3	7.8	3.9	7.3	27.7	120.0
4	Scenario 1 + Alt Water	10.8	26.6	32.6	8.6	7.2	2.8	7.5	27.7	124.0
5	Scenario 2	12.3	33.9	47.9	11.0	10.8	6.6	12.9	30.0	165.4
6	Scenario 2 + Alt CO2	10.9	27.3	38.6	9.2	8.9	4.3	8.2	27.6	135.1
7	Scenario 2 + Alt Air	11.7	27.2	43.3	11.7	8.6	5.0	12.9	30.8	151.2
8	Scenario 2 + Alt Ash	12.6	35.8	49.1	11.1	11.3	6.9	13.2	30.3	170.3
9	Scenario 2 + $1.50 Gas	12.5	26.8	36.3	11.2	10.5	6.3	12.6	30.5	146.9
10	Scenario 2 + $3.00 Gas	12.9	25.1	29.6	11.0	13.6	7.4	12.3	31.7	143.5

Regional Results - Coal Retrofits

Run	Scenario	2015 Planned Coal Retrofits (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1-10	All Cases	2.4	24.0	25.5	4.0	12.8	0.0	9.9	2.1	80.6

Run	Scenario	2015 Unplanned Coal Retrofits (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	0.8	13.6	2.9	0.0	0.0	0.7	4.1	3.9	26.0
2	Scenario 1	1.8	94.3	88.1	8.3	12.3	29.7	22.2	29.3	286.1
3	Scenario 1 + Alt Air	2.2	101.3	99.0	8.3	12.9	30.0	24.1	27.9	305.7
4	Scenario 1 + Alt Water	1.8	96.9	90.1	8.3	12.3	29.4	21.3	28.6	288.7
5	Scenario 2	1.7	83.7	71.1	8.3	11.5	24.9	16.6	26.5	244.3
6	Scenario 2 + Alt CO2	1.1	89.6	74.6	8.3	11.0	27.9	19.1	26.8	258.5
7	Scenario 2 + Alt Air	2.3	92.2	77.7	7.9	12.8	27.2	19.1	24.8	264.0
8	Scenario 2 + Alt Ash	1.6	82.4	71.7	8.3	11.0	25.0	15.6	25.3	241.0
9	Scenario 2 + $1.50 Gas	3.1	96.7	89.3	8.3	14.6	27.1	18.7	29.1	287.0
10	Scenario 2 + $3.00 Gas	3.6	101.7	104.7	8.3	14.6	29.3	19.6	30.0	311.8

Run	Scenario	2020 Unplanned Coal Retrofits (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	0.8	19.3	2.9	0.0	0.0	5.1	7.9	10.7	46.7
2	Scenario 1	9.1	199.6	195.9	15.4	34.8	59.9	50.3	45.7	610.8
3	Scenario 1 + Alt Air	7.9	186.7	194.4	13.3	28.8	46.4	44.6	42.9	565.0
4	Scenario 1 + Alt Water	6.8	175.2	170.3	15.0	26.6	53.6	39.9	45.1	532.5
5	Scenario 2	8.7	172.8	149.4	14.7	33.9	48.3	37.8	38.1	503.6
6	Scenario 2 + Alt CO2	7.5	188.4	162.4	14.7	30.7	54.9	43.4	39.6	541.6
7	Scenario 2 + Alt Air	8.0	169.2	147.4	11.4	29.7	42.0	36.3	35.2	479.2
8	Scenario 2 + Alt Ash	9.6	200.9	166.1	19.7	40.1	56.2	43.8	51.9	588.4
9	Scenario 2 + $1.50 Gas	12.4	205.2	193.4	14.7	44.2	54.1	42.9	44.0	610.7
10	Scenario 2 + $3.00 Gas	13.5	217.1	234.8	15.4	43.8	58.9	45.3	48.0	676.8

Run	Scenario	2015 Total Coal Retrofits (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	3.2	37.6	28.4	4.0	12.8	0.7	14.0	6.0	106.7
2	Scenario 1	4.2	118.3	113.6	12.3	25.0	29.7	32.1	31.4	366.7
3	Scenario 1 + Alt Air	4.7	125.3	124.5	12.3	25.7	30.0	34.0	29.9	386.4
4	Scenario 1 + Alt Water	4.2	120.9	115.6	12.3	25.0	29.4	31.2	30.7	369.4
5	Scenario 2	4.1	107.7	96.6	12.3	24.3	24.9	26.5	28.5	325.0
6	Scenario 2 + Alt CO2	3.5	113.6	100.0	12.3	23.8	27.9	29.0	28.9	339.2
7	Scenario 2 + Alt Air	4.7	116.2	103.2	11.9	25.6	27.2	29.0	26.9	344.7
8	Scenario 2 + Alt Ash	4.0	106.4	97.2	12.3	23.8	25.0	25.5	27.3	321.6
9	Scenario 2 + $1.50 Gas	5.5	120.8	114.8	12.3	27.4	27.1	28.6	31.2	367.6
10	Scenario 2 + $3.00 Gas	6.0	125.7	130.2	12.3	27.4	29.3	29.5	32.1	392.4

Run	Scenario	2020 Total Coal Retrofits (GW)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	3.2	43.3	28.4	4.0	12.8	5.1	17.8	12.8	127.4
2	Scenario 1	11.6	223.7	221.4	19.4	47.6	59.9	60.2	47.7	691.4
3	Scenario 1 + Alt Air	10.3	210.8	219.8	17.3	41.6	46.4	54.5	44.9	645.6
4	Scenario 1 + Alt Water	9.2	199.2	195.8	19.0	39.4	53.6	49.8	47.2	613.1
5	Scenario 2	11.1	196.9	174.8	18.7	46.7	48.3	47.7	40.2	584.3
6	Scenario 2 + Alt CO2	9.9	212.4	187.8	18.7	43.5	54.9	53.3	41.7	622.2
7	Scenario 2 + Alt Air	10.4	193.2	172.8	15.4	42.5	42.0	46.2	37.3	559.9
8	Scenario 2 + Alt Ash	12.0	225.0	191.5	23.7	52.9	56.2	53.7	54.0	669.1
9	Scenario 2 + $1.50 Gas	14.8	229.2	218.9	18.7	56.9	54.1	52.8	46.0	691.4
10	Scenario 2 + $3.00 Gas	15.9	241.2	260.3	19.4	56.6	58.9	55.2	50.0	757.4

Regional Results - Cumulative CAPEX for Retrofits and New Builds

Run	Scenario	2015 Coal Retrofits CapEx (Billion 2008$)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	1.4	11.9	12.1	1.6	2.8	0.2	4.8	1.3	36.1
2	Scenario 1	1.7	31.9	33.0	3.4	4.8	6.8	8.7	5.5	95.8
3	Scenario 1 + Alt Air	1.9	35.3	38.4	3.4	5.1	7.3	9.8	5.2	106.6
4	Scenario 1 + Alt Water	1.7	32.5	33.9	3.4	4.8	6.7	8.5	5.3	96.7
5	Scenario 2	1.6	29.2	28.3	3.4	4.9	5.4	7.3	4.7	84.7
6	Scenario 2 + Alt CO2	1.4	30.5	29.5	3.4	4.6	6.2	7.9	4.8	88.1
7	Scenario 2 + Alt Air	2.0	32.1	30.9	3.3	5.3	6.0	8.3	4.2	92.0
8	Scenario 2 + Alt Ash	1.6	28.9	28.7	3.4	4.8	5.4	7.0	4.3	84.1
9	Scenario 2 + $1.50 Gas	2.2	32.8	33.3	3.4	5.8	5.9	7.8	5.4	96.6
10	Scenario 2 + $3.00 Gas	2.5	34.3	38.3	3.4	5.8	6.5	8.0	5.8	104.5

Run	Scenario	2020 Coal Retrofits CapEx (Billion 2008$)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	1.4	13.8	12.1	1.6	2.8	2.3	6.1	2.7	42.8
2	Scenario 1	3.4	56.1	57.1	4.9	9.7	15.4	14.9	8.9	170.3
3	Scenario 1 + Alt Air	2.8	49.5	55.0	4.0	7.2	10.4	12.8	8.5	150.2
4	Scenario 1 + Alt Water	3.0	52.6	54.1	4.8	8.2	14.4	13.2	9.0	159.4
5	Scenario 2	3.1	48.7	45.5	4.7	12.0	13.1	11.6	9.0	147.6
6	Scenario 2 + Alt CO2	2.8	52.5	48.1	4.7	8.7	13.9	12.9	7.3	151.0
7	Scenario 2 + Alt Air	2.9	44.5	44.1	4.1	8.6	9.9	10.7	8.0	132.8
8	Scenario 2 + Alt Ash	3.6	58.9	55.6	6.0	12.7	15.9	14.2	15.1	182.0
9	Scenario 2 + $1.50 Gas	4.5	57.5	56.7	4.7	14.9	14.5	13.3	11.1	177.2
10	Scenario 2 + $3.00 Gas	4.9	61.4	69.7	4.9	13.6	14.8	14.5	11.7	195.5

Run	Scenario	2015 New Builds CapEx (Billion 2008$)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	15.4	23.4	29.4	2.7	11.6	6.9	18.2	38.1	145.6
2	Scenario 1	17.4	31.6	42.9	3.8	11.6	6.9	16.1	40.9	171.2
3	Scenario 1 + Alt Air	16.8	29.3	34.5	2.7	11.6	6.9	15.8	40.0	157.6
4	Scenario 1 + Alt Water	17.1	29.9	41.2	3.2	11.6	6.9	16.4	40.7	166.9
5	Scenario 2	20.9	38.0	56.0	8.3	13.7	8.6	20.4	44.5	210.3
6	Scenario 2 + Alt CO2	18.6	33.7	49.9	6.4	12.1	6.9	17.8	42.5	187.8
7	Scenario 2 + Alt Air	19.7	32.5	52.8	8.7	12.5	7.6	18.0	43.2	194.9
8	Scenario 2 + Alt Ash	20.9	38.7	55.1	8.3	14.0	8.8	21.7	44.4	211.9
9	Scenario 2 + $1.50 Gas	21.3	34.9	47.9	7.4	14.7	11.2	18.2	46.7	202.2
10	Scenario 2 + $3.00 Gas	22.0	32.2	40.5	5.6	20.5	15.8	19.2	50.0	205.9

Run	Scenario	2020 New Builds CapEx (Billion 2008$)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	16.6	37.3	54.0	4.5	11.6	7.2	19.3	61.0	211.5
2	Scenario 1	20.9	50.8	72.3	10.2	15.8	8.4	17.2	62.9	258.5
3	Scenario 1 + Alt Air	20.2	47.5	64.8	9.2	15.3	8.4	16.9	62.3	244.6
4	Scenario 1 + Alt Water	20.3	47.8	70.6	9.5	14.7	7.3	17.4	62.1	249.6
5	Scenario 2	23.9	59.6	90.0	12.1	18.8	11.4	29.1	68.1	313.0
6	Scenario 2 + Alt CO2	20.9	50.3	78.3	10.2	16.5	8.8	18.8	63.2	267.1
7	Scenario 2 + Alt Air	22.7	51.8	84.9	12.8	16.2	9.6	29.0	69.0	296.0
8	Scenario 2 + Alt Ash	24.2	61.9	91.3	12.2	19.4	11.7	29.5	68.7	318.9
9	Scenario 2 + $1.50 Gas	24.3	55.2	78.2	17.5	19.4	13.2	28.5	71.5	307.7
10	Scenario 2 + $3.00 Gas	25.0	60.8	71.0	15.4	37.7	16.7	27.9	74.5	329.2

Run	Scenario	2015 Total CapEx (Billion 2008$)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	16.8	35.3	41.4	4.3	14.3	7.2	23.0	39.4	181.8
2	Scenario 1	19.0	63.5	75.9	7.2	16.4	13.7	24.9	46.4	267.0
3	Scenario 1 + Alt Air	18.8	64.6	72.9	6.1	16.6	14.3	25.7	45.2	264.2
4	Scenario 1 + Alt Water	18.7	62.4	75.1	6.6	16.4	13.6	24.8	46.0	263.6
5	Scenario 2	22.5	67.1	84.3	11.7	18.6	14.0	27.7	49.2	295.0
6	Scenario 2 + Alt CO2	20.1	64.1	79.3	9.8	16.6	13.1	25.6	47.3	275.9
7	Scenario 2 + Alt Air	21.7	64.6	83.7	12.0	17.8	13.5	26.3	47.4	287.0
8	Scenario 2 + Alt Ash	22.5	67.5	83.8	11.7	18.8	14.2	28.7	48.7	295.9
9	Scenario 2 + $1.50 Gas	23.5	67.6	81.3	10.8	20.5	17.1	26.0	52.0	298.8
10	Scenario 2 + $3.00 Gas	24.5	66.6	78.8	9.0	26.3	22.3	27.2	55.8	310.3

Run	Scenario	2020 Total CapEx (Billion 2008$)								
		NPCC	RFC	SERC	FRCC	TRE	SPP	MRO	WECC	Total
1	Reference Case	18.0	51.1	66.0	6.2	14.3	9.5	25.4	63.7	254.2
2	Scenario 1	24.3	106.9	129.3	15.1	25.5	23.8	32.1	71.8	428.8
3	Scenario 1 + Alt Air	23.1	97.0	119.8	13.2	22.4	18.9	29.7	70.7	394.8
4	Scenario 1 + Alt Water	23.3	100.4	124.6	14.4	22.9	21.6	30.6	71.1	409.0
5	Scenario 2	27.1	108.2	135.5	16.8	30.8	24.4	40.7	77.1	460.6
6	Scenario 2 + Alt CO2	23.7	102.9	126.5	14.9	25.2	22.7	31.7	70.5	418.1
7	Scenario 2 + Alt Air	25.6	96.3	129.0	16.9	24.8	19.5	39.7	77.0	428.8
8	Scenario 2 + Alt Ash	27.8	120.8	146.9	18.2	32.1	27.6	43.6	83.9	501.0
9	Scenario 2 + $1.50 Gas	28.8	112.7	134.9	22.2	34.3	27.7	41.8	82.6	484.9
10	Scenario 2 + $3.00 Gas	29.9	122.2	140.8	20.2	51.4	31.5	42.4	86.2	524.7

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