Long-Term Electricity Report for Maryland

Prepared for the
Maryland Department of Natural Resources
Power Plant Research Program
Pursuant to Executive Order 01.01.2010.16

Prepared by
Exeter Associates, Inc.

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The authors assume responsibility for any errors that may be contained in the Long-term Electricity Report for Maryland.

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EXECUTIVE SUMMARY

Introduction

Governor Martin O'Malley signed Executive Order 01.01.2010.16 ("EO") on July 23, 2010 directing the Maryland Department of Natural Resources' Power Plant Research Program ("PPRP") to prepare the Long-term Electricity Report for Maryland ("LTER").[1] The purpose of the LTER is to provide a comprehensive assessment of approaches to meet Maryland's long-term electricity needs as the State faces many challenges for providing a sustainable energy future through clean, reliable, and affordable power for all Marylanders. To address the issues set forth in the EO, PPRP assessed future electric energy and peak demand requirements for Maryland over the 20-year period from 2010 through 2030. Meeting those needs was assessed under an array of alternative future economic, legislative, and market conditions. Assessment of the alternatives is based on:

- Cost and cost stability;
- Reliability;
- Environmental impacts;
- Land use impacts;
- Consistency with the State's energy and environmental laws; and
- Consistency with federal energy and environmental laws.

To conduct the analysis, a LTER Reference Case ("RC") was developed along with alternative scenarios to allow estimation of the implications of different economic, regulatory, and infrastructure conditions over the course of the 20-year study period. The LTER Reference

[1] A copy of the Executive Order is included with this report as Appendix A.

Case is based on a set of assumptions and projections assessed as a plausible "business as usual" situation. The alternative scenarios include specific assumptions and projections different from those contained in the LTER Reference Case. These scenarios facilitate the isolation of the potential impacts of significant policy changes, external factors (such as natural gas prices and load growth) and infrastructure modifications that could affect costs, emissions, the scheduling of new power plant development, fuel use, the types of power plants added to the capacity portfolio, fuel diversity, and other results. In total, 33 alternative scenarios are defined and analyzed. These scenarios are briefly described in Table ES.1.

The outcomes of the LTER Reference Case, as well as those of the 33 alternative scenarios, are highly dependent upon the assumptions and projections used to develop the scenario. While these assumptions and projections represent plausible scenarios, the outcomes could change significantly if real-world experience differs from the projections. Additionally, the modeling scenarios represent a narrow evaluation focusing primarily on economic issues. There may be benefits that accrue to end-use customers (and Maryland residents at large) that are not fully captured by such a model. These benefits include, but are not limited to, emissions reductions, system reliability, increased diversity of fuel, overall economic development, and improvements in public health and welfare.

Table ES.1 LTER Scenarios

Category	Scenarios	Description
LTER Reference Case ("RC")	LTER Reference Case assumptions	See Table ES-2
Infrastructure Alternative Scenarios	Mt. Storm to Doubs Transmission Upgrade ("MSD")	RC assumptions with the MSD upgrade increasing transmission capacity between Western PJM and Maryland beginning in 2015.
	Mid-Atlantic Power Pathway ("MAPP") Transmission Line	RC assumptions with the MAPP line increasing transmission capacity between Maryland the Delaware/New Jersey region beginning in 2018.
	Calvert Cliffs 3 ("CC3")	RC assumptions with CC3 on-line in 2019 at a capacity of 1,600 MW.
	Calvert Cliffs 3 & National Carbon Legislation ("NCO2")	RC assumptions with CC3 and NCO2 starting in 2015 at $16 per ton of CO and increasing to $54 per ton by 2030.
	Mt. Storm to Doubs and MAPP Transmission Lines	RC assumptions with both MSD and MAPP added.
	Calvert Cliffs 3, National Carbon Legislation, Mt. Storm to Doubs, and MAPP	RC assumptions with the CC3, NCO2, MSD, and MAPP assumptions listed above.
National Carbon Legislation Alternative Scenarios	National Carbon Legislation	RC assumptions with NCO2 assumptions as noted above.
	National Carbon Legislation and Mt. Storm to Doubs	RC assumptions with NCO2 and MSD assumptions as noted above.
Natural Gas Price Alternative Scenarios	Lower Priced Natural Gas	Natural gas price assumption lowered so it reaches $4.63 in 2030. Other RC assumptions unchanged.
	Lower Priced Natural Gas and Mt. Storm to Doubs	Lower natural gas price assumption and MSD added to the RC.
	Higher Priced Natural Gas	Natural gas price assumption increased so it reaches $11.70 in 2030. Other RC assumptions unchanged.
	Higher Priced Natural Gas and Mt. Storm to Doubs	Higher natural gas price assumption and MSD added to the RC.
Load Growth Alternative Scenarios	Lower Load Growth	Load growth lowered by approximately 10 percent. Other RC assumptions unchanged.
	Lower Load Growth and Mt. Storm to Doubs	Lower load growth and MSD added to the RC.
	Lower Load Growth, Calvert Cliffs 3, National Carbon Legislation, Mt. Storm to Doubs, and MAPP	Lower load growth and CC3, NCO2, MSD, and MAPP added under the assumptions noted above.
	Higher Load Growth	Load growth raised by approximately 10 percent. Other RC assumptions unchanged.
	Higher Load Growth and Mt. Storm to Doubs	Higher load growth and MSD added to the model.
	Higher Load Growth, Calvert Cliffs 3, National Carbon Legislation, Mt. Storm to Doubs, and MAPP	Higher load growth and CC3, NCO2, MSD, and MAPP added under the assumptions noted above.

Category	Scenarios	Description
High Renewables Alternative Scenarios	High Renewables	Maryland RPS reaches 30 percent by 2030 and met with in-State renewable energy development.
	High Renewables and Mt. Storm to Doubs	30 percent RPS and MSD added to the RC.
	High Renewables, Calvert Cliffs 3, and National Carbon Legislation	30 percent RPS with CC3 and NCO2 assumptions as described above.
	High Renewables, Calvert Cliffs 3, National Carbon Legislation, Mt. Storm to Doubs, and MAPP	30 percent RPS with the CC3, NCO2, MSD, and MAPP added under the assumptions noted above.
Aggressive Energy Efficiency Alternative Scenarios	Aggressive Energy Efficiency	Maryland fully meets the EMPOWER Maryland ("EMP") goals by 2020. Other RC assumptions unchanged.
	Aggressive Energy Efficiency and Mt. Storm to Doubs	EMP goals met with the MSD line added to the model.
	Aggressive Energy Efficiency, Calvert Cliffs 3, and National Carbon Legislation	EMP goals met with CC3 and NCO2 added under the assumptions noted above.
	Aggressive Energy Efficiency, Calvert Cliffs 3, National Carbon Legislation, Mt. Storm to Doubs, and MAPP.	EMP goals met with CC3, NCO2, MSD, and MAPP added under the assumptions described above.
Climate Change Alternative Scenarios	Climate Change	PJM December 2010 Base Case Load Forecast adjusted for a 2.3°F increase by 2030. Other RC assumptions unchanged.
	Climate Change, Calvert Cliffs 3, National Carbon Legislation, Mt. Storm to Doubs, and MAPP	Adjusted load growth forecast with CC3, NCO2, MSD, and MAPP added under the assumptions described above.
Additional Scenarios	Coal Plant Life Extension and Mt. Storm to Doubs	Coal-fired power plant life extended and MSD added to the RC.
	PJM High Energy Efficiency and Low Load Growth	The lower load growth assumptions combined with aggressive energy efficiency policies in all PJM states.
	Proposed Environmental Protection Agency ("EPA") Regulations and Mt. Storm to Doubs	The new EPA regulations respecting mercury and cooling water added to the model and MSD added to the RC.
	Aggressive Energy Efficiency and High Renewables	A combination of the aggressive EE and high RPS assumptions in Maryland.
	Medium Renewables Scenario	An increase in the Maryland RPS requirement midway between the RC and the High Renewables scenario.

For each of the scenarios, including the LTER Reference Case, model simulations were run. The assumptions and projections required to be input into the model include:

- Energy consumption and peak demand;
- Power plant operating characteristics (operating costs, capacity, fuel, heat rate, capital costs, and emission rates for CO_2, SO_2, NO_x, and mercury) for all existing power plants and generic power plant types that the model may select for addition to the portfolio of power plants on a least-cost basis;
- Data related to the configuration and carrying capacity of the electric transmission system;
- Quantitative reliability requirements;
- Regulatory environment (state renewable energy portfolio standards, environmental restrictions on (or allowance prices for) specific pollutants);
- Fuel prices (natural gas, coal, oil, uranium);
- Power plant retrofit costs; and
- Certain other assumptions and projections.

A summary of the key assumptions and projections for the LTER Reference Case is presented in Table ES.2. The key assumptions and projections for the alternative scenarios are presented in Table ES.3.

Table ES.2
Summary of Key Assumptions and Projections for the LTER Reference Case

Assumption/Projection Issue	Description
Energy and peak demand forecast	PJM's December 2010 Base Case forecast for energy and peak demand was relied upon but modified to account for energy efficiency and conservation programs in Maryland (EmPOWER Maryland) and those in place in other PJM states and also modified for the projected impacts of plug-in electric vehicles on loads in Maryland and PJM.
Transmission infrastructure	The transmission infrastructure includes all PJM transmission lines, and transmission lines in other regions, in place in 2010 plus the Trans-Allegheny Interstate Line ("TrAIL"), which was energized in June 2011. (Note: alternative scenarios address the construction of the Mid-Atlantic Power Pathway (MAPP) and the upgrade of the Mt. Storm to Doubs transmission line.)
Natural gas prices	Natural gas prices are projected to increase from $4.46/mmBtu in 2011 (2010$) to $8.01/mmBtu in 2030 (2010$). (Note: alternative scenarios address higher and lower natural gas price projections.)
Coal prices	Coal prices (delivered) vary by transmission zone over the 20-year forecast period, but in general remain relatively flat.
Nuclear fuel prices	Nuclear fuel prices are projected to decline from $0.75/mmBtu (2010$) in 2011 to $0.66/mmBtu (2010$) in 2030.
Wind power capacity factors	On-shore and off-shore wind turbines are assumed to operate at a 30 percent capacity factor and a 40 percent capacity factor, respectively.
Solar capacity factor	Photovoltaic systems are assumed to operate at a 15 percent capacity factor.
Wind power construction costs	On-shore and off-shore wind projects are assumed to have an overnight construction cost in 2010 dollars of $2,200 per kW and $4,260 per kW, respectively.
Nuclear power plant construction costs	New nuclear generation facilities are assumed to have an overnight construction cost of $5,870 per kW (2010$).
Financial assumptions	The debt/equity ratio for new power plants is assumed to be 50 percent debt and 50 percent equity; the nominal cost of debt is assumed to be 7 percent; the nominal cost of equity is assumed to be 12 percent; the annual inflation rate is assumed to be 2.5 percent.
Renewable energy portfolio standards ("RPSs")	It is assumed that Maryland will meet its Tier 1 and Tier 2 RPS requirements through the retirement of Renewable Energy Certificates ("RECs"). The Maryland solar requirement is assumed to be met with solar RECs through 2018; for years following 2018, a portion of the solar RPS requirement would be met through Alternative Compliance Payments; by 2030, approximately 50 percent of the Maryland solar energy requirement is assumed to be met through Alternative Compliance Payments.
Environmental Regulations	EPA's existing regulations (the Clean Air Transport Rule, the Greenhouse Gas Tailoring Rule, and New Source Performance Standards) integrated into the model.
Energy Efficiency and Conservation Programs	EmPOWER Maryland goals for demand reductions are assumed to be fully met. The EmPOWER Maryland goals for energy reductions are assumed to be met at the 60% level. Energy efficiency and conservation programs in other states are assumed to meet their goals in rough proportion to the assumptions relied on for Maryland, but with more ambitious programs achieving a smaller percentage of their energy goals and less ambitious programs achieving a larger percentage.

Table ES.3
Summary of Key Assumptions and Projections for the LTER Alternative Scenarios

Assumption/Projection Issue	Description
Calvert Cliffs Nuclear Unit 3	For those scenarios that include construction of Calvert Cliffs 3, the plant capacity is assumed to be 1,600 MW; construction cost is assumed to be $10 billion; and the in-service date is assumed to be 2019.
MAPP Transmission Line	The MAPP transmission line is assumed to come on-line in 2018 with a transfer capability of 2,500 MW between PJM Southwest and PJM Mideast, and a transfer capability of 1,250 MW between PJM Southwest and PJM South.
Mt. Storm to Doubs Transmission Line Upgrade	The Mt. Storm to Doubs transmission line upgrade is assumed to be in-service beginning in 2015 with a transfer capability of 1,700 MW between the Allegheny Power System region and PJM Southwest.
National Carbon Legislation	Assumed to become effective in 2015 and implemented as a cost on carbon emissions of $16 per ton (2010 dollars) in 2015, increasing by $1 per ton annually through 2023, then increasing at an average of $4.50 per ton per year through 2030. A federal RPS is included with the carbon legislation and is set at 12 percent by 2020. States with more aggressive RPSs meet the higher standard.
High and Low Natural Gas Prices	The low gas price assumption is gas prices starting at $3.56 per mmBtu in 2011 rising to $4.63 by 2030. The high gas assumption is gas prices starting at $5.50 per mmBtu in 2011 and increasing to $11.70 by 2030. All prices are in 2010 dollars.
High and Low Loads	Low loads increase at a growth rate 0.5 percentage points below the LTER Reference Case growth rate. High loads increase at a growth rate 0.5 percentage points higher than the LTER Reference Case growth rate.
High Renewables	The Maryland RPS is increased from a 20 percent renewable requirement by 2022 to a 30 percent requirement by 2030. All RPS compliance, including the solar carve-out, is met through retirement of Renewable Energy Certificates.
Aggressive Energy Efficiency	Maryland implements more aggressive energy efficiency/conservation programs such that 100 percent of the EmPOWER Maryland energy reduction goal is achieved by 2020 and demand reductions equal to 150 percent of the EmPOWER Maryland goal are achieved by 2030.
Climate Change	Average ambient temperatures increase by 2.3 degrees Fahrenheit by 2030 compared to long-term normal temperatures, with temperature increases between 2010 and 2030 linearly interpolated.

Key Results

The results of the model runs include, but are not limited to, information on power plant additions and retirements; fuel consumption by fuel type; emissions from Maryland generation and, alternatively, by consumption; energy and capacity prices; and net imports of energy by transmission zone. The modeling was conducted using the Ventyx Integrated Power Model ("IPM"). The IPM, developed by Abb/Ventyx, is a set of models designed to reflect the market factors affecting power prices, emissions, generation, power plant development (and retirements), fuel choice, and other power market characteristics. The IPM is a zonal model, which separates the PJM Region (and other regions) into distinct zones based on transmission paths and electric utility territories. In the IPM, different portions of Maryland are in three different zones – PJM Mid-Atlantic Southwest, PJM Mid-Atlantic East, and PJM Allegheny Power Systems ("APS").[2] Some of the modeling results, therefore, are at the zonal level.

LTER REFERENCE CASE RESULTS

- No new generating capacity is needed in PJM to meet reliability requirements before 2018. Between 2010 and 2030, PJM adds approximately 30,000 MW of new natural gas-fired capacity.
- Based on least-cost criteria, all new generating capacity projected to be constructed to satisfy reliability requirements will be fueled by natural gas. Renewable generating capacity is also added during the 20-year study period to meet RPS requirements in Maryland and other states.
- Approximately 16,250 MW of renewable generating capacity is added to PJM between 2010 and 2030.
- Emissions of NO_x, SO_2, and mercury from Maryland power plants subject to Maryland's Healthy Air Act ("HAA") remain below the HAA caps for those pollutants throughout the 20-year study period.

[2] PJM Mid-Atlantic Southwest contains Baltimore Gas & Electric, Pepco (both Maryland and Washington D.C. service territories) and the Southern Maryland Electric Cooperative. PJM Mid-Atlantic East contains all of New Jersey, Delmarva Power (both Maryland and Delaware territories) and PECO Energy Company. PJM APS covers the entire Allegheny Power System company footprint.

- Emissions of CO_2 exceed Maryland's budget under the Regional Greenhouse Gas Initiative ("RGGI") beginning in 2020, which will require Maryland generation facilities to purchase RGGI emission allowances from other RGGI states and/or purchase offsets in order for the State to comply with its RGGI commitments.
- Real energy prices are projected to increase by between 5 and 6 percent per year through 2020, then remain relatively flat for the final 10 years of the study period. The increase in prices during the first ten years of the period largely reflects increases in fuel prices and increasing reliance on less efficient generating units to meet consumption requirements. During the second 10-year period, the impact of increases in fuel prices is off-set by the construction of new, more efficient power plants.
- Capacity prices, which can increase or decrease significantly from year to year, generally increase over the 2010 through 2030 period and begin to converge at prices approximating the cost of new entry (about $250 per MW-day) towards the end of the study period.

ALTERNATIVE SCENARIO RESULTS

Capacity Additions

- Under assumptions of high load growth over the study period, PJM adds between 52,000 and 58,000 MW of new gas-fired generating capacity compared to 30,000 MW in the LTER Reference Case.
- Under assumptions of low load growth over the study period, PJM adds between 8,000 and 15,000 MW of new gas-fired capacity compared to 30,000 MW in the LTER Reference Case.
- The implementation of more aggressive energy efficiency and conservation programs in Maryland results in a reduction in new gas-fired generating capacity in PJM of about 2,000 MW relative to the LTER Reference Case.

- Relative to the LTER Reference Case, the adoption of national carbon legislation results in approximately 7,000 MW of additional PJM-wide natural gas-fired power plants over the 20-year study period, which reflects increased retirements of coal-fired plants and reduced coal-fired generation from retrofitted coal plants.
- Construction of new transmission lines in PJM (the MAPP line and the Mt. Storm to Doubs transmission line upgrade) are shown to have little or no effect on PJM-wide power plant additions over the study period.

Energy Prices

- Wholesale energy prices under most alternative scenarios are generally consistent with the LTER Reference Case energy prices with two exceptions – natural gas price scenarios and the scenarios that consider national carbon legislation. Under the other alternative scenarios, wholesale energy prices vary only marginally from the LTER Reference Case energy prices.
- Under assumptions of high natural gas prices, all-hours wholesale energy prices are approximately $21 to $25 per MWh (in 2010 dollars) higher than the LTER Reference Case energy prices by 2030.
- Under assumptions of low natural gas prices, all-hours wholesale energy prices are approximately $22 per MWh (in 2010 dollars) lower than the LTER Reference Case energy prices by 2030.
- Under assumptions of national carbon legislation, all-hours wholesale energy prices are approximately $21 per MWh (in 2010 dollars) higher than the LTER Reference Case energy prices by 2030.

Maryland Emissions based on Maryland Generation

- Under all of the scenarios considered, in-State emissions of SO_2, NOx, and mercury are below the caps imposed by Maryland's Healthy Air Act.

- In-State CO_2 emissions vary by scenario. In general, CO_2 emissions exceed Maryland's budget under the Regional Greenhouse Gas Initiative during the course of the study period.
- Development of the Mt. Storm to Doubs transmission line upgrade reduces the amount of CO_2 emissions in Maryland since construction of the line facilitates greater levels of imported energy from more western portions of PJM. (Note: CO_2 emissions in PJM are not reduced as a result of this line, but CO_2 emissions from Maryland power plants are.)
- Construction of the Calvert Cliffs 3 nuclear power plant reduces in-State CO_2 emissions by over 10 percent (approximately 4 million tons per year relative to the LTER Reference Case).
- The introduction of national carbon legislation reduces CO_2 emissions in Maryland by approximately 8 percent (3 million tons per year) by 2030.
- Under the high load growth assumption, emissions of CO_2 in Maryland increase relative to the LTER Reference Case by approximately 10 percent by 2030. Under the low load growth assumption, there is a significant reduction in CO_2 emissions in Maryland relative to the LTER Reference Case beginning in the early to mid-2020s. By 2030, however, there is only a slight difference between the LTER Reference Case and the low load scenarios. (Under the low load scenario, fewer new, more efficient plants are being added relative to the LTER Reference Case, which serves to erode a large portion of the reduced CO_2 reductions that would be achieved under conditions of lower loads with other factors held constant).
- The high renewables scenario, which is based on the assumption of a 30 percent RPS by 2030 in Maryland, reduces Maryland CO_2 emissions by approximately 3 percent by 2030 relative to the LTER Reference Case.
- The high energy efficiency/conservation scenario, which is based on adoption of a more aggressive energy efficiency/conservation program in Maryland, results in reduced CO_2 emissions of approximately 6 percent by 2030 relative to the LTER Reference Case.

Maryland Emissions Based on Maryland Consumption

- Emissions of CO_2 and SO_2 are highest (relative to the LTER Reference Case) under the high gas price scenarios since there are fewer retirements of coal fired facilities and coal generation runs more intensively. The lowest levels of CO_2 emissions are associated with the high renewables scenarios, the low gas price scenarios, and the scenarios that include construction of Calvert Cliffs 3 combined with national carbon legislation. The lowest levels of SO_2 emissions are associated with the high renewables scenarios and the scenarios that include national carbon legislation.
- Emissions of mercury are highest under the low load scenarios, since fewer new, more efficient plants are being built and there is a heavier reliance on coal-fired generation. In general, however, there is not a large degree of variation in mercury emissions among the scenarios.
- Emissions of NO_x are lowest under the high renewables scenarios and the scenarios that include national carbon legislation. The highest levels of NO_x emissions are associated with the scenarios that assume relatively slow growth in loads and those that assume high natural gas prices (relative to the LTER Reference Case).

Fuel Diversity

- For all scenarios, fuel supply diversity increases over the course of the 20-year study period as the share of coal-fired generation declines and the proportion of generation relying on natural gas increases.
- The greatest increases in fuel diversity are related to the scenarios that include construction of Calvert Cliffs 3, high load growth, and high renewables development.
- The smallest increases in fuel diversity are associated with those scenarios that entail slower growth in load, such as the low load growth scenarios and the high energy efficiency scenarios.

Capacity Prices

- In general, capacity prices increase when capacity becomes tight in a zone, and decline following the introduction of a new power plant.
- The general trend is for capacity prices to be relatively low in the early years of the study period, then to increase as the need for new generating capacity increases and plants begin to be built within the model. There is a general tendency for the capacity prices among zones to converge towards the end of the study period, and gravitate towards values that approximate the cost of new power plant entry.

Land Use

- Land use requirements on a per-MW-of-installed-capacity basis are significantly higher for on-shore wind and solar than for nuclear and natural gas-fired capacity.
- Land use requirements for on-shore wind capacity on a per-MW basis are approximately ten times higher than for solar capacity.
- Maryland land-use requirements for all scenarios except the High Renewables scenarios are between 15,000 and 20,000 acres for all new generating capacity over the 20-year study period. For all of the scenarios, the majority of land use requirements are associated with new renewable energy projects.
- For the High Renewables scenarios, Maryland land use requirements for new generation exceed 100,000 acres over the 20-year study period. Almost all of that requirement is related to the development of on-shore wind generation.[3]

[3] For the High Renewables scenarios, it is assumed that all additional renewable energy projects required to meet a more aggressive Maryland Renewable Energy Portfolio Standard would be sited in Maryland. On-shore wind eligible to meet Maryland's RPS, however, may be located outside Maryland. To the extent that the higher RPS requirements assumed under the High Renewables scenarios would be sited outside Maryland, the Maryland land use requirements estimated for these scenarios would be correspondingly lower.

Renewable Energy Certificate Prices

- Under the LTER Reference Case and the High Renewables scenarios, Tier 1 RECs prices are estimated to range between $2 per REC to $28 per REC (in 2010 dollars). RECs prices increase through 2014, then stabilize within the range of $24 per REC to$26 per REC between 2015 and 2023. After 2023, RECs prices decline in real terms to a level of $12 per REC by 2030.
- For the scenarios that entail significantly higher energy prices than projected for the LTER Reference Case (for example, the cases that include national carbon legislation and high natural gas prices), the projected RECs prices (2010 dollars) are lower than in the LTER Reference Case and drops to zero towards the end of the study period. The reason for this result is that the RECs prices are calculated as the residual revenue required by a new renewable energy project to cover all costs of ownership and operation, and the federal Production Tax Credit incentive. Higher market prices for energy, therefore, result in a smaller residual revenue requirement that would need to be recovered through RECs prices.
- The low natural gas price scenarios result in the highest projected RECs prices due to the low energy prices projected for these scenarios. Nominal RECs prices, if unconstrained, would exceed the $40-per-REC Alternative Compliance Payment ("ACP") contained in the RPS legislation beginning in 2019 and extending through the end of the 20-year study period. Since the ACP acts as a cap on RECs prices, nominal RECs prices were assumed to reach a maximum of $38 per REC, with the $2-per-REC difference between the $40 ACP and $38 assumed maximum value representing the transaction costs. In real terms, RECs prices under the low natural gas price scenarios reach $33 per REC in 2013, and decline to $23 per REC in 2030.

SUMMARY

Table ES.4 ranks the production costs, generator revenues, emissions, fuel diversity, and generic natural gas capacity builds across the scenarios. The first column of the table ranks the total production costs over the 20-year study period (in 2010 dollars) associated with each scenario. Total production costs are calculated as the sum of fuel, fixed, and variable costs that generators in PJM incur to produce electricity. The fixed and variable costs include operations and maintenance ("O&M") expenses as well as emissions costs. As shown in the total production cost column of Table ES.4, the scenarios that include implementation of national carbon legislation involve the highest total production costs.

The second column of Table ES.4 ranks the wholesale energy market revenues that generators earned throughout the study period (in 2010 dollars). Wholesale energy market revenues are highest in the scenarios that include national carbon legislation or high natural gas prices.

The third column of Table ES.4 ranks capacity market revenues earned by PJM generators over the study period (in 2010 dollars) and shows that capacity market revenues are typically highest under assumptions of high load, low natural gas, and aggressive energy efficiency and conservation.

Table ES.4 also ranks the total NO_x, SO_2, and CO_2 emissions from PJM generation units in each scenario. The ranking of the emissions across the three pollutants are generally stable, and scenarios with relatively high CO_2 emissions typically also have high NO_x and SO_2 emissions. It warrants mention that the total CO_2 emissions across the scenarios vary within a nine percentage point range, and the total NO_x and SO_2 emissions vary within a six percentage point range. The seventh column in Table ES.4 ranks the fuel diversity indices across scenarios.

The fuel diversity index is a measure of the mix of fuels used to generate electricity in PJM. A higher fuel diversity index indicates greater fuel diversity.

The last column of Table ES.4 ranks the total generic natural gas capacity (in MW) that was added by the model in PJM to satisfy load and reliability requirements. The scenarios that include national carbon legislation induce coal power plants to retrofit or retire and as such, these scenarios, along with the high load scenarios, involve higher levels of generic natural gas capacity additions.

Table ES.4
PJM-Wide Summary Statistics by Scenario

	Total Production Costs	Wholesale Energy Revenues	Capacity Revenues	Total NO_x Emissions	Total SO_2 Emissions	Total CO_2 Emissions	2030 Fuel Diversity Index*	Total Gas Capacity Built
LTER Reference Case	◑	◑	◑	●	●	●	◑	◑
MSD	◑	○	◑	●	●	◑	◑	◑
MAPP	◑	◑	●	●	●	●	◑	◑
CC3	○	○	○	◑	◑	◑	◑	○
MSD + MAPP	◑	◑	◑	◑	●	●	◑	◑
CC3 + NCO2	●	●	◑	◑	○	○	●	●
CC3/NCO2/MSD/MAPP	●	●	○	○	◑	○	●	●
NCO2	●	●	◑	◑	◑	◑	●	●
NCO2 + MSD	●	●	◑	◑	◑	○	●	●
High Gas	◑	●	○	●	●	●	◑	◑
High Gas + MSD	◑	●	○	●	●	●	◑	◑
Low Gas	○	○	●	◑	○	◑	◑	○
Low Gas + MSD	○	○	●	◑	○	◑	◑	◑
High Load	◑	◑	●	◑	●	◑	●	●
High Load + MSD	◑	◑	●	◑	◑	◑	●	●
High Load + CC3/NCO2/MSD/MAPP	●	●	●	○	◑	○	●	●
Low Load	○	○	○	●	◑	●	○	○
Low Load + MSD	◑	○	○	●	◑	●	○	○
Low Load + CC3/NCO2/MSD/MAPP	◑	◑	○	○	○	○	◑	○
High Renew	○	○	◑	○	○	◑	◑	○
High Renew + MSD	○	◑	◑	○	○	◑	◑	○
High Renew + CC3/NCO2	●	●	◑	○	○	○	●	◑
High Renew + CC3/NCO2/MSD/MAPP	●	●	○	○	○	○	●	●
EE	○	○	○	●	●	●	◑	○
EE + MSD	○	○	◑	●	●	●	◑	○
EE + CC3/NCO2	●	◑	●	○	○	○	●	◑
EE + CC3/NCO2/MSD/MAPP	●	◑	●	○	◑	○	●	◑
Climate Change	◑	◑	●	●	●	●	◑	●
Climate Chg + CC3/NCO2/MSD/MAPP	●	●	●	◑	◑	◑	●	●

● = top third ◑ = middle third ○ = bottom third

*Fuel diversity indices are ranked as follows: ● = < 0.88 ◑ = ≥ 0.88 and ≤ 0.915 ○ = > 0.915

1. INTRODUCTION

1.1 Purpose

On July 23, 2010, Governor Martin O'Malley signed Executive Order 01.01.2010.16 ("EO") directing the Maryland Department of Natural Resources' Power Plant Research Program ("PPRP") to develop a long-term electricity report for the State of Maryland.[4] The central purpose of the Long-term Electricity Report ("LTER") is to provide a comprehensive assessment of approaches to meet the long-term electricity needs of Marylanders through clean, reliable, and affordable power. The LTER does not present policy recommendations and the scenarios developed for analysis should not be interpreted as recommended policies. The LTER provides policy-makers with the anticipated effects of both alternative policies and external (non-policy related) factors such as high (and low) natural gas prices, high (and low) growth in electric loads, and climate change. Effects include, but are not limited to, wholesale energy prices, capacity prices, emissions, fuel use, fuel diversity, and land-use. As such, the LTER should be viewed neither as an energy plan for the State nor as an integrated resource planning document.

To satisfy the purpose of the EO and to meet the requirements set forth therein, PPRP assessed future electricity and peak demand needs for Maryland over the 20-year period from 2010 through 2030. Various methods to meet these needs were assessed under an extensive array of alternative future economic, legislative, and market conditions. PPRP's assessment of the identified alternatives is based on:

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[4] See Appendix A for the full Executive Order.

- Feasibility;
- Cost and cost stability;
- Reliability;
- Environmental impacts;
- Land use impacts;
- Consistency with the State's environmental laws; and
- Consistency with federal energy and environmental laws.

There are inherent trade-offs among certain evaluation criteria elements. For example, enhancing reliability typically entails increased costs due to either increased generation capacity for a given level of peak demand or increased transmission capacity to permit greater importation of power. Similarly, minimizing adverse environmental impacts may also entail higher costs in the short term as renewable generation tends to be more expensive than conventional generation (fossil fuels). Policy-makers may determine, however, that any short-term cost impact from renewable generation may ultimately be balanced by the long-term benefits of improved health, price stability, energy diversity, and reduced emissions.

To develop this report, including the identification of the alternative methods by which to meet the future energy and peak demand requirements of the State and the specification of input assumptions needed to conduct the technical analysis, PPRP sought input from and consulted with a spectrum of interested parties, including:

- State government agencies including the Maryland Energy Administration and the Maryland Department of the Environment;
- Office of People's Counsel;

- PJM Interconnection, LLC;
- Maryland's electric distribution companies;
- Competitive retail electricity suppliers;
- Wholesale electricity suppliers;
- Natural gas companies;
- Renewable electricity generators;
- Energy service companies specializing in demand response;
- Large electricity consumers;
- Organizations representing environmental interests; and
- Organizations representing consumer interests.

The input provided by these organizations was valuable throughout the scoping and analysis phases of report development and also throughout the process of drafting the LTER. The range of perspectives provided by these organizations helped to facilitate the development of a varied set of methods to satisfy the gap in electric generating capacity that will need to be filled to ensure the reliable supply of electricity for Maryland consumers.

1.2 Approach Overview

The steps taken to conduct the analysis required to fulfill the specifications contained in the EO are outlined below. A more detailed description is contained in later chapters of this report.

<u>Step 1. Identify current and planned electric generating capacity and transmission system capabilities</u>. The data developed for this step were used to assess the magnitude of the gap

between electric energy and peak demand requirements for Maryland and the amount of electric energy and capacity available to meet those requirements. Current generating capacity is defined herein as the portfolio of power plants presently operating or available to operate within Maryland (i.e., existing plants) and those projects for which all air permits have been obtained and construction has begun as of mid-2010 (i.e., planned capacity). Current generating capacity is also adjusted downward to reflect announced retirements of specific power plants.

The transmission system infrastructure included in this analysis represents the PJM system current as of 2010 plus the Trans-Allegheny Interstate Line ("TrAIL"), a 500-kV line extending from Southwestern Pennsylvania, through West Virginia, and into Virginia. The TrAIL was energized in June 2011. The transmission system is represented as transmission transfer capabilities between transmission zones.[5]

Energy and demand requirements were based on the most recent PJM annual forecast of peak demand and energy, which was published in December 2010. The PJM peak demand and energy forecasts were adjusted to reflect expected impacts of plug-in electric vehicles ("PEVs") and state-level energy conservation and efficiency programs.

<u>Step 2. Define a LTER Reference Case and alternative scenarios to facilitate estimation of the implications of different economic and regulatory conditions over the course of the 20-year study period</u>. The LTER Reference Case represents current regulatory and economic conditions, including existing renewable energy portfolio requirements, energy conservation and efficiency programs, and environmental legislation. For the LTER Reference Case, forecasted inputs such

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[5] The method by which transmission system capabilities are reflected in the analysis is discussed in detail in Chapter 2 of the LTER.

as load levels and fuel prices are based on projections assessed to be the most plausible. The alternative scenarios were developed to assess the impacts and implications of potential policy changes or external factors[6] that could emerge over the 20-year study period and affect projected costs, emissions, scheduling of new power plant development, fuel-use, types of power plants that are added to the capacity portfolio in future years, fuel diversity, and other results. In aggregate, 33 alternative scenarios were defined based on changes in possible federal and State legislation and policies, potential electric transmission line construction, potential nuclear power plant construction, fuel price changes that are different from those reflected in the LTER Reference Case, growth in future loads that is different from what is represented in the LTER Reference Case, and combinations of the above factors. Included in the 33 alternative scenarios is a set of scenarios based on assumptions of climate change over the study period.

Step 3. Specify input assumptions for the LTER Reference Case and all alternative scenarios. A wide range of input assumptions is required to fully and precisely define each of the scenarios considered (i.e., the LTER Reference Case and all of the alternative scenarios). These assumptions include, but are not limited to: future fuel prices (natural gas, fuel oil, coal, nuclear), plant variable and fixed operating costs, plant capital costs (including financing costs), load growth, the types of renewable energy projects to be constructed in future years, the extent to which energy efficiency and conservation goals will be attained in terms of energy reductions and reductions in peak demand, power plant heat rates (the efficiency with which power plants convert the energy in fuel into usable electricity), power plant emission rates (for SO_2, NO_X,

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[6] External factors inclue the pace of economic recovery, fuel prices, and infrastructure changes.

mercury, and CO_2), power plant outage rates due to maintenance and forced outages, and electric transmission system transfer capabilities between transmission zones.

Step 4. Obtain input and feedback from the Power Plant Research Advisory Committee. The Power Plant Research Advisory Committee ("PPRAC") [7] was provided with the preliminary specifications of the LTER Reference Case and the alternative scenarios as well as the preliminary modeling assumptions anticipated to be used for the analysis. To facilitate PPRAC's involvement, several all-day meetings were held to explain and delineate the scenarios and the input assumptions. Comments from PPRAC members were addressed and written responses are provided on the PPRP website. (All presentation materials, comments, and responses are available at http://esm.versar.com/pprp/PPRAC/default.htm.)

Step 5. Conduct modeling test runs and evaluations. After all of the scenarios were specified and the modeling input assumptions developed, the input assumptions and scenario specifications were input into the models, and the preliminary modeling results were obtained on a scenario-by-scenario basis. The results were carefully reviewed to ensure correctness – that the models were appropriately handling the inputs and scenario specifications in the manner intended. This step involved a degree of iteration and some refinement of the input assumptions and scenario specifications to ensure proper coordination of the inputs with the requirements of the models.

Step 6. Conduct modeling runs. Once it was determined that the models were operating properly and employing correctly the input assumptions provided, the LTER Reference Case and the

[7] The PPRAC is an advisory body to the Secretary of the Maryland Department of Natural Resources. PPRAC members, appointed by the Secretary, include representatives from State government, the electric utility industry, environmental organizations, PJM, academia, and the private sector.

alternative scenario runs were performed; outputs were analyzed and compared; summary tables and charts were developed; and a draft report was prepared.

Step 7. Obtain public input and modify the analysis/report as needed. Upon completion of the initial draft and final draft report, a notice of availability for public comment was placed in the Maryland Register. Further, public informational meetings were held to obtain input and feedback from as large an audience as possible. The comments received through the public review process were addressed and written responses were posted on the PPRP website. Modifications were made to the initial draft and draft final reports in light of the comments received through the public review process.

The following chapter describes the models used, the inputs required by the models, and 4the outputs provided by the models. The chapter also discusses the limitations specific to the models.

2. MODEL DESCRIPTION

2.1 Introduction

The results presented in this report are based on modeling conducted using the Ventyx Integrated Power Model ("IPM"). Developed by Abb/Ventyx, IPM is a set of models designed to reflect the market factors affecting power prices, emissions, generation, power plant development (and retirements), fuel choice, and other power market characteristics. This chapter describes IPM and explains how IPM operates. In particular, this chapter explains how the model addresses the estimation of energy prices and capacity prices, the determination of new plant construction and retirements of certain existing plants, the estimation of electric energy production by fuel and by region, and the estimation of power plant emissions (CO_2, $NO_{X,}$ SO_2, and mercury).

2.2 Model Description

2.2.1 Overview of Ventyx Model

The Ventyx reference case is the platform used for modeling the various scenarios in the Long-term Electricity Report for Maryland ("LTER"). The Ventyx reference case includes market-based forecasts of North American power, fuel, emissions allowances, and renewable energy certificate prices that are internally consistent with one another, that is:[8]

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[8] The Ventyx reference case is Ventyx's base line national projection. This projection differs from the LTER Reference Case which is based on certain Maryland-specific and PJM-specific data developed by PPRP, current legislation, and most plausible projections of other relevant factors. The specifications of the LTER Reference Case scenarios are detailed in Chapter 3 of this report – LTER Reference Case Assumptions.

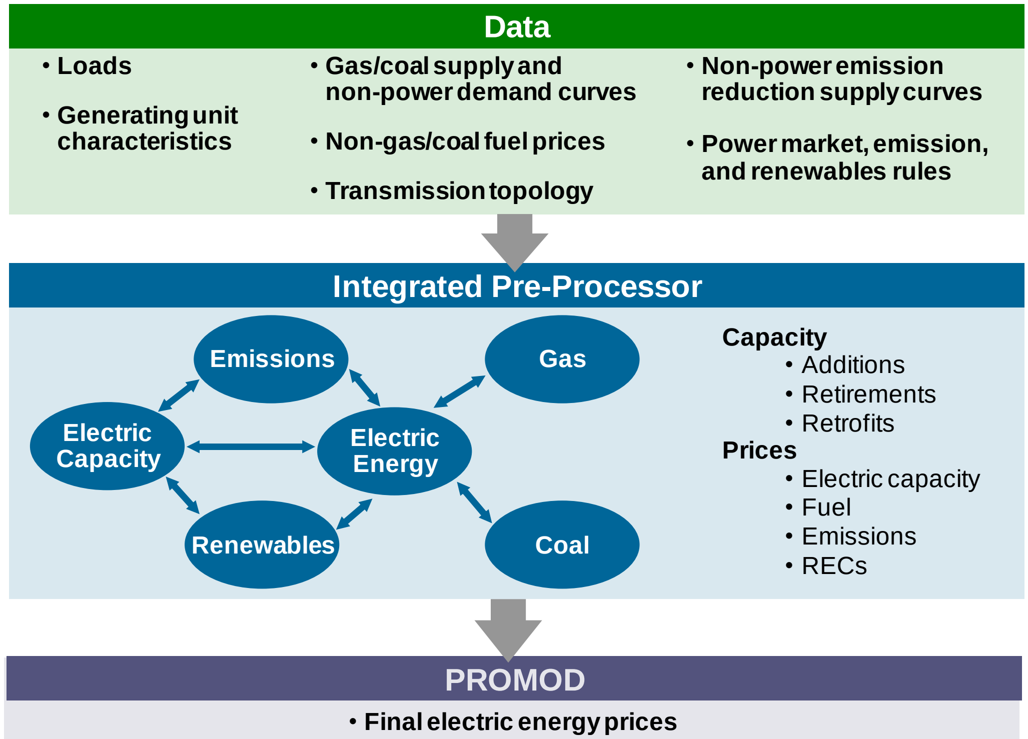
- Carbon allowance prices are internally consistent with the proposed carbon emissions cap, and the costs to control carbon emissions;
- Natural gas and coal prices are internally consistent with the carbon allowance prices, and the associated power-sector consumption of each fuel;
- Capacity additions, retirements, and retrofits are internally consistent with the allowance and fuel prices;
- Electric energy and capacity prices are internally consistent with the capacity additions, emission allowance costs, and fuel prices; and
- Renewable energy certificate prices are internally consistent with state, multi-state, and federal renewable portfolio standards (if specified as a policy condition) and electric energy and capacity prices.

As shown in Figure 2.1, the Ventyx forecasting methodology consists of three steps:

(1) Collecting and inputting data;
(2) Running the Integrated Pre-processor; and
(3) Running the PROMOD model.

Each of these steps is discussed in detail below.

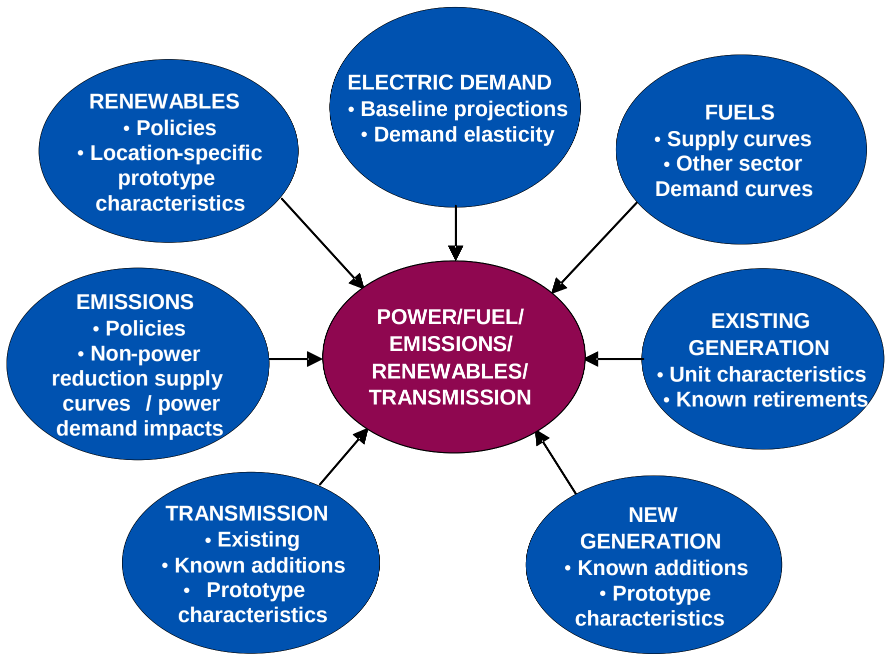
Figure 2.1 Forecasting Process



2.2.2 Data Inputs

The forecast process requires a significant amount of input data, as shown in Figure 2.2. The model is represented by the oval in the center; groups of data inputs are represented by the seven blue ovals in the periphery.

Figure 2.2 Ventyx Forecast Data Inputs



These data were assembled from the following sources:

- **Electric Demand** - The peak and energy forecasts are based on a combination of Federal Energy Regulatory Commission ("FERC") Form 714 filings; Independent System Operator ("ISO") reports; and the U.S. Department of Energy, Energy Information Administration ("EIA") Annual Energy Outlook. These forecasts are adjusted as necessary based on assumptions of new energy efficiency programs. For the LTER, electric demand for PJM and for the PJM zones that include portions of Maryland, forecasted energy and peak demands were modified to account for energy conservation and efficiency programs (e.g., EmPOWER Maryland) and the impacts of plug-in electric vehicles. These adjustments were developed by PPRP.
- **Fuels** - The majority of the required data are drawn from Ventyx's proprietary fuel forecasts. Information about pipeline expansion costs is from industry publications.

- **Existing Generation** - The majority of the required data are from Ventyx's Energy Velocity Suite. Information about the costs to retrofit existing units with Carbon Capture and Sequestration ("CCS") capability, and the resulting impacts on operational parameters, is derived from engineering analysis conducted by Ventyx.
- **New Generation** - Data on planned additions are from Ventyx's Energy Velocity Suite. Information about the characteristics of prototype units is derived from engineering analysis conducted by Ventyx and PPRP.
- **Transmission** - Data on the existing transmission system and proposed additions is based on industry research conducted by Ventyx and PPRP.
- **Emissions** - Information about policies and supply curves outside the power sector are derived from publicly available literature.
- **Renewables** - Data on current generating plants are from Ventyx's Energy Velocity Suite. Information about policies and the characteristics of prototype capacity additions is derived from publicly available literature and data, research by Ventyx, and analysis conducted by PPRP.

With respect to generating resource additions, this report assumes that new generating capacity will enter the marketplace in two phases. In the first phase—called Initial Entry—all capacity that is currently under construction is assumed to be completed and brought on line. In the second phase, generic units are brought on line to meet future market needs, taking advantage of profit opportunities that are forecasted to arise. Renewable energy sources are added as necessary to meet regional or federal renewable portfolio standards.

The starting point for the simulations is the current plant expansion plans of the utilities, independent power producers, and other suppliers in each region. Information from Ventyx's Energy Velocity Suite database is used to develop this starting point.

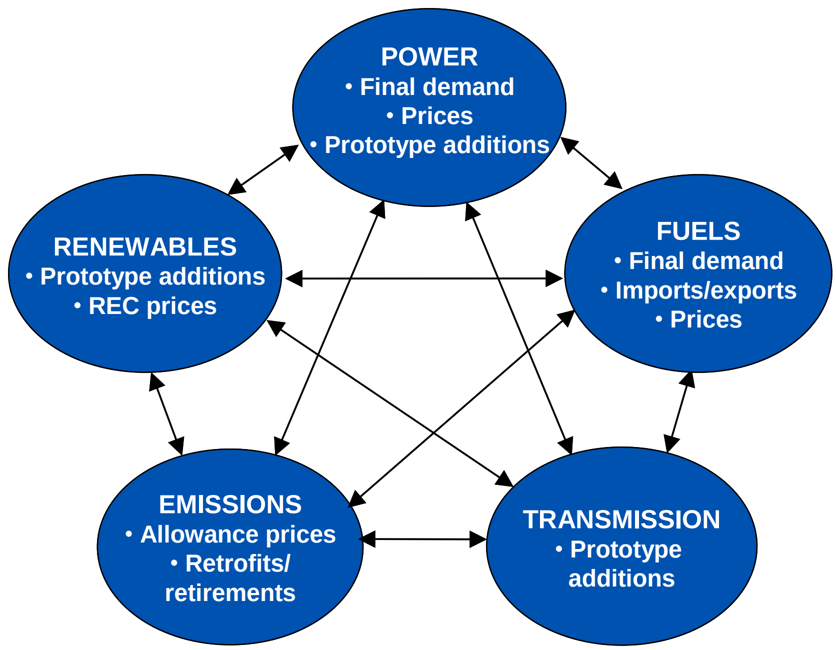
In order to meet future needs for new generating capacity, the LTER considers nine types of generic conventional resources during the 20-year forecast period. New resources are added in response to forecast electric demand, whereby the added capacity is economically viable and the reserve margins are either in accordance with regional requirements or are sufficiently maintained to meet reliability standards. The nine conventional resource types are: gas-fired combined cycle natural gas ("CCNG"), aero derivative ("AD") and combustion turbine ("CT") units; and combined cycle equipped with carbon capture and sequestration. In addition, renewable resources including wind, photovoltaic solar, landfill gas, wood-fired biomass, and geothermal are added to meet expected state and federal renewable energy requirements. The capacity additions are modeled to enter in response to economic conditions such that the level of new entry represents results in a long-term equilibrium state for new entrants responding to expected profit opportunities. The "balanced" market that results is characterized by constant long-term reserve margins, relatively flat annual prices, and an annual profit level for new capacity sufficient to cover operational as well as fixed and financing costs.

Note that IPM does not adjust electric loads for the price elasticity effects of changes in energy prices. Electric energy consumption and peak demand are model inputs and are not adjusted downward in response to increases in electric power prices or adjusted upward in response to decreases in electric power prices.

2.2.3 Integrated Pre-Processor

An overview of the Integrated Pre-Processor is provided in Figure 2.3. As the figure shows, the process comprises five modules, which iterate on an annual basis. For example, the operations component of the Power Module simulates power plant dispatch, preliminary power prices, fuel consumption, and emissions for each month of 2012 based on values from the prior iteration for: 1) power plant capacity and natural gas pipeline decisions, and 2) inputs from the other modules. For the first iteration, the Power Module applies the previous year's gas forecast values. The simulated power sector demand for natural gas is passed to the operations component of the Fuel Module, which simulates natural gas prices for all months of 2012 in the current iteration.

Figure 2.3 Ventyx Forecasting Process



Once the operations components of the Power and Fuel Modules are simulated for all 12 months of 2012 in the current iteration, the 2012 power and fuel prices, emissions, and other intermediary outputs are passed to the Investment Component. The Investment Component of the Power and Fuel Modules is then simulated for 2012, producing updated values of conventional power plant capacity additions, retirements, and retrofits; annual electric capacity prices; and annual CO_2 prices. The decisions made in the Investment Component are then passed into the Operations Module as an additional iteration. If the updated values for 2012 of any of these variables are different than those from the prior iteration, the updated values are passed back to the Investment Component, which will produce a refined schedule for additions, retirements, and retrofits. This iterative process continues until convergence is achieved.

The following describes the key aspects of each of the five modules comprising the forecasting process.

Power Module.

The Power Module is a zonal model of the North American interconnected power system covering 70 zones. The Module simulates separate hourly energy and annual capacity markets in all zones. The Module simulates the operations of individual generating units, as opposed to aggregations of units. As indicated above, the Power Module comprises two components which simulate: 1) operations; and 2) conventional power plant capacity additions, retirements, and retrofits.

Operations Component. For given values of the variables simulated by the other modules from the prior iteration, and a variety of fixed input assumptions such as generating unit characteristics described below, the Operations Component simulates a constrained least-cost commitment and dispatch of all the power plants in the system, taking into account hourly loads, operating parameters and constraints of the units, system constraints such as spinning reserve requirements, and transmission constraints.

Investment Component. For a given set of the values of variables from the Operations Component, such as hourly electric energy prices, and from the other modules, the Investment Component simulates the conventional power plant capacity additions, retirements, and retrofits likely to occur in the market.

Capacity Addition Decision. The investment decision for capacity additions is a multi-step process that identifies both energy and capacity revenue associated with potential new resources. The Investment Component identifies in each forecast year the list of technology types that are available for expansion in each zone. Profitability of each technology for each zone is based on whether energy market revenues are greater than the sum of: 1) expenses for fuel, emission allowances, variable operations and maintenance ("O&M"), fixed O&M; and 2) amortized capital costs.

Once the most profitable resource for the zone has been identified, the Investment Component then adjusts the price curve for that zone given the presence of the first resource, and identifies the economics of all available resources, assuming the first resource has been built. This process continues until developable resources are no longer available. This process provides an order for development within each zone based on first-year energy economics. The profitability may be positive or negative at this stage. In later steps, the Investment Component considers the value of capacity markets and the effects of minimum reserve constraints.

The next step is to identify resource addition profitability for the entire system as well as by individual capacity market. At this point, the capacity price for each resource addition is obtained. The capacity value available to the resource is calculated as either: (1) the minimum of the adjusted Cost of New Entry ("CONE") value, relative to an established Variable Resource Requirement ("VRR") curve, or (2) the payment required to permit the resource to recover capacity value (total cost minus energy revenue). After this step, the model establishes profitability based on energy and capacity revenues for each reserve addition.

Following the identification of resource addition profitability, the Investment Component performs capacity additions from greatest to least system profitability until all profitability is eliminated from the system and all minimum reserve margin constraints are met. Resources with negative profitability may be added to fulfill the minimum resource requirement. Conversely, resources may be added based on profitability in excess of the established minimum reserve margin. Therefore, the resulting capacity additions, if sufficient resources are available, will result in actual reserve margins at or above target reserve margins.

In determining reserve margins, the Investment Component considers: 1) thermal, hydro, and intermittent resources within the zone; 2) coincident peak less interruptible demand response resources; and 3) transmission transfers into and/or out of the zone. Intermittent resources, such as wind and solar power, are de-rated for capacity addition decisions based on availability at time of peak. The objective of the transmission transfers is to levelize the capacity prices within a planning region. A planning region is defined by the markets where there are developed capacity planning regions, such as PJM, or where there are defined North American Electric Reliability Corporation ("NERC") capacity planning regions.

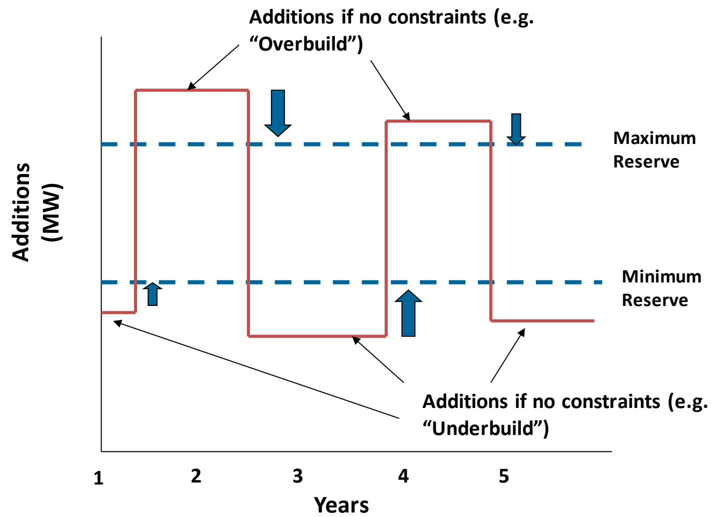
The capacity addition decision is an iterative process to gather intelligence from the markets before the decision is finalized. The iterative process steps are outlined below:

1. Identify the capacity price before additions, which is characterized as the Cost of New Entry within a zone;
2. Identify the most profitable incremental capacity additions given the energy price for that iteration;
3. Perform another iteration given the change in energy price with the revised resources after the capacity addition is made;
4. Determine profitability after step three – if the resource is profitable, then the resource is added; and
5. Evaluate the transmission transfers to determine if it is more profitable to build and sell capacity into another zone after the resource has been added.

This process may continue for up to ten iterations before finalizing the decision.

To ensure that regions do not overbuild based on economics, the decision criteria may also include a maximum reserve margin as shown in Figure 2.4.

Figure 2.4 Capacity Decision Reserve Constraints



Retirement Decisions. For economic retirements, the Investment Component retires all generating units with negative gross margins: energy and capacity revenues minus expenses for fuel, emission allowances, variable O&M, and fixed O&M for four consecutive years by the final iteration in a year.

The Investment Component may also retire a generating resource based on the age of the resource. For age-based retirements, the following service lives are assumed:

- Coal: 65 to 75 years;
- Nuclear: 60 years;
- Combined Cycle: 60 years;
- Gas Turbines: 60 to 75 years; and
- Oil Turbines: 60 to 75 years.

If there is no capacity addition made, the capacity price is based on the minimum of the revenue deficit for the most economic resource to add or the most economic resource to retire.

Retrofit Decisions. For retrofits, the Investment Component identifies, from a list of generating units that can be retrofitted, the units that would be more profitable in the current year with the retrofit than in the existing configuration, taking into account the capital costs of the retrofit amortized over the likely remaining life of the unit. Once the Investment Component decides to retrofit a unit, it passes the updated operational characteristics of the unit to the Operations Component.

Capacity Price. The annual capacity price in each zone is calculated as the amount, measured in dollars per kW-year, that the marginal unit in the zone required to satisfy the reserve margin would need over and above energy market revenues to break even financially, including the amortized capital cost of the unit. In the final iteration, a decision is made as to whether it would be more profitable to sell the capacity to another zone given the transmission constraints, which would then set the capacity price in both zones.

Fuels Module.

The Fuels Module consists of three sub-modules, one each for oil, natural gas, and coal.

Natural Gas Sub-Module. The Natural Gas Sub-Module produces forecasts of monthly natural gas prices at individual pricing hubs.

The Operations Component of the Natural Gas Sub-Module consists of a model of the aggregate U.S. natural gas sector. For each month and iteration, it executes in the following manner:

- The Operations Component includes an econometric model of Lower 48 demand in each of the sectors other than power, relating monthly consumption to the Henry Hub price.
- For each iteration of the Operations Module, natural gas demand by the power sector is derived from the prior iteration of the Power Module.
- Liquefied Natural Gas ("LNG") supply is forecast using a proprietary global LNG model and Henry Hub prices from the previous iteration. This model utilizes forecasts of global LNG demand and supply.
- Domestic supply is represented in the Operations Component by exogenous Lower 48 production declines and exogenous assumptions about deliveries from Alaska; a pair of econometric equations relating Lower 48 productive capacity additions to Henry Hub prices in previous months and Lower 48 capacity utilization to the current Henry

Hub/West Texas Intermediate ("WTI") price; and net storage withdrawals to balance supply and demand to the extent available storage capacity will permit.

- The Henry Hub price is simulated as the price that balances demand and supply, including net storage withdrawals.

Coal Sub-Module. The Coal Sub-Module utilizes a network linear programming ("LP") routine that satisfies, at least cost, the demand for coal at individual power plants with supply from existing mines using the available modes of transportation. For each year and iteration, the Coal Sub-Module executes in the following manner:

- For each iteration, demand by each power generating plant is derived from the prior iteration of the Power Module. The Sub-Module takes into account the potential to switch or blend coals at each plant where such potential exists.
- Supply is represented by mine-level short- and long-run marginal cost curves, maximum output, and developable reserves.
- Transportation is represented as the minimum cost rate for each mine-plant pairing, taking into account the modes of transportation that are possible, e.g., rail, truck, barge.
- The network LP routine generates forecasts of annual FOB prices by mine, delivered prices by plant, and the characteristics of the coal delivered to each plant (e.g., sulfur and heat content).
- Known contracts between specific mines and power plants are represented. These contracts influence the forecast of spot coal produced at each mine.

The Coal Quality Market Model ("CQMM") is used to forecast the future U.S. consumption, allocation, and delivered price of coal from every mine to every boiler over the study period. CQMM uses a network linear program to find the minimum cost coal allocation for each boiler, given model inputs and constraints. The cash cost of producing thermal coal is a primary input to CQMM. Ventyx mine cost modeling incorporates the primary cost drivers for the U.S. coal industry, including:

- Continued regulatory pressure from emissions regulation;
- Cost-increasing regulatory pressure from new mining safety regulations and expected increased scrutiny of mountaintop mining in Appalachia;
- Decreasing labor productivity and flat capital investment;
- Near-term increases in financing costs;
- Limits on economies of scale;
- Modestly increasing prices for fuel, equipment, tires, and explosives over the short- to medium-term;
- Decreasing labor costs as a result of a larger labor pool; and
- An aging workforce that is nearing retirement in the East with associated legacy healthcare and pension costs.

Oil Sub-Module. U.S. crude oil prices are based on conditions in the world oil market. Based on extensive prior analysis, the feedback to the world oil market from the markets represented in the North American forecast (i.e., power, natural gas, coal, and emissions) appears to be extremely weak. Moreover, the effects on the world oil market of the types of policies or exogenous events that might be modeled, such as a CO_2 cap-and-trade program, are also very weak. As a result, it is appropriate to treat the world oil market—and more specifically U.S. crude oil prices—as an exogenous input, as opposed to modeling it explicitly. Ventyx currently uses the forecast of the West Texas Intermediate ("WTI") price from the U.S. Energy Information Administration's *2010 Annual Energy Outlook*. Ventyx generates forecasts of region-specific prices for refined oil products burned in power plants (e.g., diesel and residual fuel oil), based on an analysis of historical relationships between these prices and the WTI price.

Transmission Module. The construction of additional electric transmission capacity between adjacent zones is simulated. Such construction results in increases of transfer limits between the zones of interest, which were selected in order to integrate expanded wind capacity in the Great Plains and Rocky Mountain regions. The process was performed in the same manner as the Investment Component of the Fuels Module, which was based on hourly electric energy prices. Ventyx identified pairs of adjacent zones for which the basis differentials over the course of the year were large enough that a power producer in one of the zones would increase its profits, taking into account the amortized capital costs of the new facilities, by building such a facility.

Emissions Module. The Emissions Module considers existing and potential regulations restricting the emissions of CO_2, SO_2, and NO_X. The following paragraphs describe how the module considers potential CO_2 regulations; the Module considers existing regulations for the other pollutants in a similar manner.

The Module is based on the assumption that there will be a cap-and-trade program for CO_2 allowances that covers the entire U.S. economy, with annual CO_2 emission caps.[9] The Module simulates the investment and operating decisions that power sector participants, as well as participants in other sectors of the economy, will make in response to such caps and the resulting allowance prices.

[9] Not all of the scenarios run for the LTER assume a national CO_2 emissions reduction policy. For those scenarios that do not include such a policy, no CO_2 constraints are included in the modeling.

The Module includes a supply curve for CO_2 emission reductions from other sectors of the economy, including permitted international and domestic offsets. The supply curve is expressed in terms of reductions in CO_2 emissions in millions of tons at various CO_2 allowance prices. The Module also contains a supply curve for CO_2 emission reductions from the power sector. The power sector supply curve is based on an engineering analysis of the potential to reduce CO_2 emissions at every existing power plant in the U.S. It includes reducing capacity factors of existing units, retrofitting existing plants with carbon capture and sequestration ("CCS") capability, and the combination of retiring an existing plant and replacing it with a new plant that has lower carbon intensity. The supply curve is updated annually in the simulation to reflect mitigation actions simulated in previous years (e.g., power plant retirements). In addition, because a CCS retrofit reduces the capacity and maximum energy output of the plant – and thus plant revenues – the supply curve depends on energy and capacity prices. Therefore, the supply curve is updated with new electric energy and capacity prices as well as fuel prices within a simulation year after each iteration. In each iteration, the Module determines the emissions of CO_2 by the power sector from the prior iteration and the remainder of the economy, and compares this emissions total to the regulated cap. In the event emissions exceed the cap, the Module uses the supply curves for the power sector and the remainder of the economy to identify the set of decisions that would be made to reduce emissions to achieve the cap and the associated CO_2 emission allowance price. The decisions for the power sector, which may include retirements and retrofits of specific plants, are then passed to the Power Module.

Ventyx uses a proprietary emission forecast model to simulate emission control decisions and emission results simultaneously in the three cap-and-trade markets (SO_2, NO_X annual, and

NO_X ozone season). This economic model acts as a central system planner to minimize system-wide total costs of environmental compliance across the entire forecast period. Unit characteristics, simulated operations, emission control costs, control efficiencies, announced installations, and state-level EPA Transport Rule emission caps provide the input data. Based on these inputs, the model forecasts emission prices, installation dates, and resulting system-wide emissions. In addition to the input data, the model relies on the following assumptions:

- State-level caps with limited trading;
- Current traded prices;
- After known announcements, economics determine equipment installation timing;
- The installation of additional control equipment does not significantly change the plant dispatch (or merit) order;
- Selective Catalytic Reduction ("SCR") and wet Flue Gas Desulfurization ("FGD") will be used for NO_X and SO_2 control, respectively;
- Environmental control investments will be reflected in allowance prices;
- Limits on the number of forecast installations per year; and
- Cost and efficiency values developed from EPA analysis.

Renewables Module.

The Renewables Module simulates the market reaction to the imposition of state, multi-state, or federal renewable portfolio standards ("RPS"). RPSs imposed in the same year at multiple levels (federal and state) can also be modeled. The Module simulates annual additions of renewable capacity that will be made in each zone, by technology type, given: 1) the values of variables from other modules, and 2) the relevant RPSs. The Module also simulates the annual renewable energy certificate ("REC") prices for each jurisdiction that imposes an RPS.

The Module calculates these values using zone-specific supply curves for renewable additions. Each supply curve is expressed in terms of the amount of capacity that would be constructed, measured in MWh of renewable energy generated, at various REC prices. These supply curves are adjusted to take into account zonal energy and capacity prices. As in the Investment Component of the Power Module, the Renewables Module first identifies all renewable capacity additions that can be made solely on the basis of first-year economics (without regard to RPS requirements), taking into account energy and capacity market revenues, variable and fixed O&M, and amortized capital costs.

After all such additions have been made, the Module then identifies states (or the nation as a whole in the event that a federal RPS is modeled) in which the RPS is not satisfied. The Module then identifies the renewable capacity additions that: 1) together satisfy the RPS, and 2) require the lowest first-year REC price. In such instances, the REC price is set as the additional payment, measured in dollars per MWh, that the marginal capacity addition requires to break even financially, taking into account the energy market revenues, variable and fixed O&M expenses, and amortized capital costs.

The forecast of REC values is based on the premise that renewable energy generators rely on RECs to complement energy and capacity revenues to meet their production costs and levelized capital requirements. Another source of revenue is the Production Tax Credit ("PTC"). The following methodology is applied to calculate REC values:

1. Estimate the average levelized capital requirement in dollars-per-MWh by renewable type;

2. Estimate expected gross margins for renewable generation in the state as a combination of the following:

    - Energy market gross margins from the Ventyx Fall 2010 Reference Case;

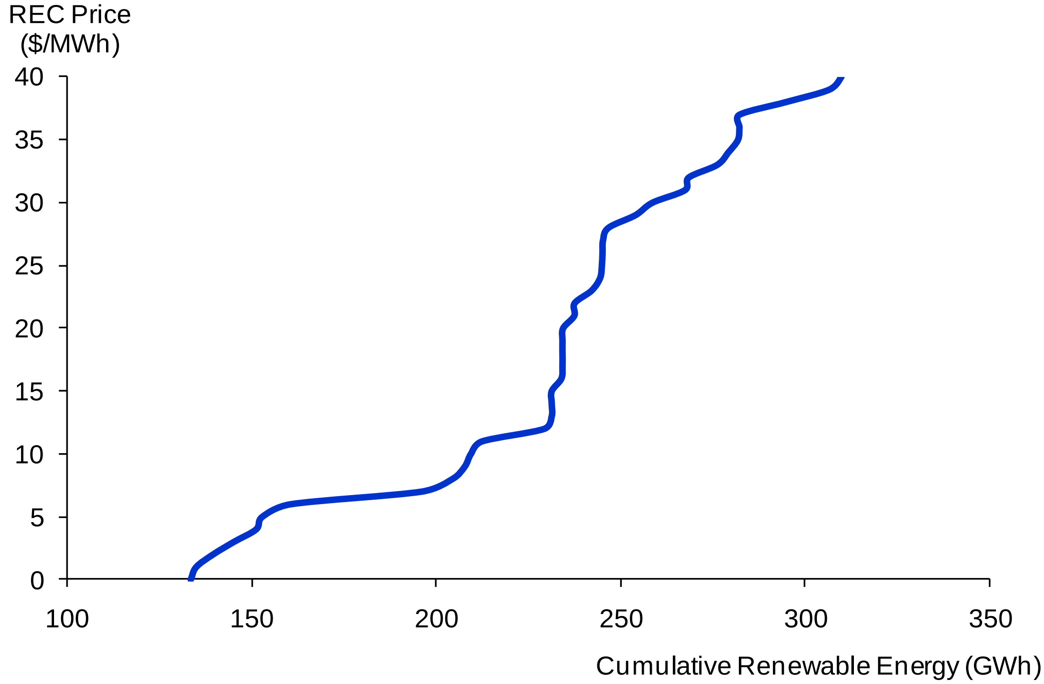
    - The Production Tax Credit;

3. Calculate the deficit in meeting the levelized capital requirements (Step 1, above) from the gross margins calculated in Step 2; and

4. Calibrate REC prices in 2010 through 2012 to reflect currently traded REC market prices.

For each year of the analysis, a supply curve is developed for all the renewable assets in the appropriate renewable market area. Figure 2.5 presents a sample supply curve. The X-axis shows the cumulative renewable capacity in cumulative GWh or GW. The Y-axis presents the deficit as calculated in step 3, above, for each eligible renewable unit. Depending upon where the demand for RECs falls, the price will adjust accordingly. The flat section of the curve represents the cost of typical wind units, while the increasing portion of the stack represents newer additions with higher capital costs.

Figure 2.5 Renewable Energy Credit Supply Curve Example



2.2.4 PROMOD

PROMOD IV® is an integrated electric generation and transmission market simulation system. It incorporates extensive details in generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operating conditions, and market system operations. PROMOD IV performs an 8760-hour commitment and dispatch recognizing both generation and transmission impacts at the nodal level. PROMOD IV forecasts hourly energy prices, unit generation, revenues and fuel consumption, external market transactions, transmission flows, and congestion and loss prices.

The heart of PROMOD IV is an hourly chronological dispatch algorithm that minimizes costs (or bids) while simultaneously adhering to a variety of operating constraints, including generating unit characteristics, transmission limits, fuel and environmental considerations, transactions, and customer demand. The PROMOD IV data inputs, simulation methodologies, and outputs are described in detail below.

Generation Types. PROMOD IV may be configured to model any number and type of generating units. Fossil-fired generators such as steam turbines, simple-cycle combustion turbines, and combined-cycle turbines are committed and dispatched based on operating costs and characteristics. Nuclear plants are typically modeled as must-run units that always operate at, or near, full available capacity. Hydro units may have both a minimum capacity or run-of-river portion and a peak-shaving capacity that is distributed to hours with the highest load levels.

Non-dispatchable resources with established generation patterns such as wind farms or certain co-generation facilities may be modeled as must-take with on-peak/off-peak energy distributions or as an hourly profile. Any number of user-specified unit additions can be modeled in PROMOD IV.

Generator Operating Characteristics. The operating range for generators is defined with Minimum Operating Capacity and Maximum Operating Capacity inputs. Capacity blocks or segments may be defined between the minimum and maximum capacities, for which distinct bids or operating costs may be calculated. An Emergency Capacity may be specified above the Maximum Operating Capacity and will be dispatched only in a loss-of-load situation. A total of seven segments (including the minimum and emergency segments) can be modeled for each generator. Heat rates may be defined using incremental rates (mmBtu per MWh) for each capacity segment, or using an input/output curve expressed as either an exponential equation or a fifth-order polynomial. Heat rates are grouped into profiles and assigned to generators on a monthly basis, thus facilitating the setting up of seasonal heat rates for each generator.

Generators may be input with a specific start-up fuel (which may be different than the one used during normal operation), and start-up thermal energy requirements. An additional dollars-per-start-up cost adder may be included, if desired. In order to prevent excessive cycling of units, minimum run-times and minimum down-times also may be input. These operational characteristics are used in PROMOD IV's commitment logic to control how often generators are started up and shut down. Both ramp up rate and ramp down rate limits (input as MW per hour) are enforced in the hourly dispatch decision.

<u>Generator Outages</u>. Planned maintenance may be input into PROMOD IV using predefined dates, or may be automatically scheduled based on reliability criteria and individual generator maintenance requirements. Specific maintenance schedules may be entered with predefined dates; they may be full or partial (with a MW de-rate), and may be specified as day, night and/or weekend only.

PROMOD IV uses a Monte Carlo technique to simulate the uncertainty of generator availability. Each generator's availability is based on inputs for forced outage rate and mean time to repair. Using these inputs, PROMOD IV will randomly determine "black out" dates during which the generator will not be available if called upon. Generators will initially be committed for a week assuming they will not experience a forced outage. If an outage occurs, the generator may be recommitted once it returns to service.

Partial unit outages can also be modeled in PROMOD IV by creating the appropriate data assumptions for the available ratings on individual capacity blocks rather than assuming that the entire availability rating applies to the maximum capacity. If the user assigns an availability rating to individual capacity blocks, the Monte Carlo algorithm will also consider partial outages.

A unique availability schedule for each generation resource is generated for each Monte Carlo "draw," and the entire simulation is repeated. PROMOD IV features an "Intellidraw" function that adjusts annual outages determined from the initial Monte Carlo draw process to match the input forced outage rate in order to achieve convergence with fewer draws. This occurs by lengthening or shortening each outage proportionally until convergence is achieved. The availability schedules for each Monte Carlo draw are saved in a library and can be used in future simulations, thereby ensuring repeatability of results.

Transactions. PROMOD IV supports a comprehensive set of buy/sell transactions, including forward products (fixed volume and price), options, spot transactions (hourly or block, price sensitive or index-based), and a variety of scheduled transactions (peak reducing, valley fill, on-peak, and off-peak). External market areas can also be modeled as buy/sell transactions with hourly price spreads and time-varying capacity limits.

Load. Load by market area includes an hourly shape with annual peak and energy forecasts. Area loads typically represent control areas but are user-defined so that individual customer classes can also be modeled. Area loads are allocated down to load buses based on the load levels for the individual bus derived from the imported power flow case. Interruptible loads may be modeled as a resource of last resort (before load shedding) or as a dispatchable resource with an associated bid price. Interruptible loads may contribute to ancillary services by user designation. For the LTER analysis, interruptible loads are treated as dispatchable.

Environmental Modeling. Environmental constraints can be modeled at three levels of detail within PROMOD IV:

1. Environmental production by unit can be reported and accounted for;
2. Environmental costs/constraints can be considered in determining the dispatch rate or bid for a unit; and
3. The system can be dispatched such that an environmental limitation (e.g., seasonal NO_x limitations) will not be violated.

For the LTER analysis, SO_2, CO_2, and NO_X are modeled with unique production rates, specified by unit, which may vary over time.

Unit Commitment. The unit commitment logic realistically models generator constraints for minimum runtime and minimum downtime, along with start-up costs, capacity bids, and energy bids. This process starts with an initial unit commitment loading order for the week, and then performs a full hourly dispatch with either zonal transmission or a full load flow for each hour of the week. Checking for violations of minimum runtime and minimum downtime constraints on each unit, the logic looks for alternative commitment decisions that improve the economic performance of the system, calculating bid adders to ensure that the cost of startup and minimum runtimes are taken into account. Once the commitment schedule is determined, another full hourly dispatch is performed to produce the final results. This process integrates the unit commitment decision with full transmission analysis, so that a true security-constrained unit commitment optimization is achieved.

Unit Dispatch, Bids, and Costs. PROMOD IV calculates dispatch marginal costs for each unit capacity segment based on its variable costs, which include fuel (commodity, handling, transportation), emissions, O&M, and fuel auxiliaries. These costs may be further modified to represent bid strategies using price markups, fixed cost adders, and explicit bid overrides. Bids for startup-cost, minimum loading, and incremental dispatch capacity may be defined. Additionally, a fixed component representing all or some portion of fixed costs may be entered; this bid will be added to the minimum loading bid.

Based on the reactance of the connected transmission lines, shift factors are calculated for each bus, so that generation injected will flow into the system adhering to the physical characteristics of the grid. PROMOD IV incorporates each generator's bids, shift factors, and ramp rate limits into a linear program to optimize the dispatch across the entire system for each hour – honoring transmission constraints – for a full security-constrained economic dispatch.

Transmission. PROMOD IV uses a transportation model to represent the transmission system. This option allows users to capture the high level impacts of area-to-area (market zone or sub-zone) transmission constraints without requiring detailed bus-level transmission data and in-depth knowledge of the transmission system. The solution utilizes a linear program that solves a load balance equation by forcing the sum of the generation, load, import, export energy, and losses to equal zero for each area. If generation shortages or transmission constraints lead to the inability to meet demand, emergency energy is created to achieve balance in a given area. Individual line flows and interface flows are monitored. Bi-directional tariff charges may be entered as economic hurdles to power exchange, and a loss factor is included to capture the effect of transmission losses.

System Reliability. Individual generators may be designated as must-run, so that they always operate at least at minimum capacity when available, regardless of cost. Additionally, security regions may be defined, which may be met with a set of generators.

PROMOD IV considers operating reserve requirements in its commitment and dispatch algorithm. The operating reserve requirement can consist of both a spinning and non-spinning requirement. This requirement can be specified as a percent of load, a percent of large steam unit, or flat MW value. Additionally, individual generating units as well as transactions can be flagged to contribute to either spinning reserve, non-spinning reserve, or not contribute to reserve at all. If a unit contributes to either reserve, the unit contribution can also be limited as a percent of maximum capacity or undispatched remaining capacity, or both.

3. LTER REFERENCE CASE MODELING ASSUMPTIONS

3.1 Introduction

As noted in Chapter 1 of this report, the LTER Reference Case scenario was developed along with 34 alternative scenarios based on an array of modifications to the LTER Reference Case assumptions. This chapter presents the key assumptions relied upon for the LTER Reference Case and a discussion of the reasons behind the relevant assumptions and the sources of the data relied upon. In succeeding chapters addressing the alternative scenarios, the assumption modifications that define those scenarios will be presented.

Each section of this chapter describes the following types of assumptions in detail: transmission topology; loads; generation unit cost and operational characteristics for nuclear, fossil-fuel, and renewable generation; environmental policies; and renewable energy portfolio standards. Many of the assumptions relied upon in the LTER Reference Case are inherently uncertain over the course of the 20-year study period. Major areas of uncertainty include fuel prices; the transmission system build-out; future policy implementation regarding renewable energy, energy conservation, energy efficiency, and emissions; load growth; and the potential construction of a third nuclear unit at the Calvert Cliffs site. Because these uncertainties could significantly affect future energy and capacity prices, the overall generation mix, power supply price variability, and emission levels, we have addressed these uncertainties through the development of the alternative scenarios.

The following categories of input assumptions are addressed in this chapter:

- Transmission topology;

- Energy consumption and peak demands;
- Generation unit costs and operational characteristics;
- Environmental policies; and
- Renewable energy policies.

Each category contains key assumptions, which are presented and discussed below.

3.2 Transmission Topology

The Integrated Pre-processor ("IPP") and PROMOD models separate the relevant geographic areas contained within PJM into market centers or "bubbles" shown in Figure 3.1, below. The transfer capability between bubbles is particularly important because transmission constraints are the main cause of price differentials across PJM. The transmission topology will change if new backbone transmission projects, such as the Mid-Atlantic Power Pathway ("MAPP") or the Mt. Storm to Doubs transmission upgrade, are constructed in the region. Most of Maryland's energy users (those within the Pepco and BGE zones) fall within the PJM Southwest bubble ("PJM-SW"); Allegheny customers fall within the PJM-APS bubble; and Delmarva customers fall within the PJM-Mid-East bubble. It is important to note that the prices in all of the PJM bubbles are relevant when determining the price of electricity in the State of Maryland because PJM operates as an integrated market.

Figure 3.1 Modeled Transmission Zones in PJM and Surrounding Areas

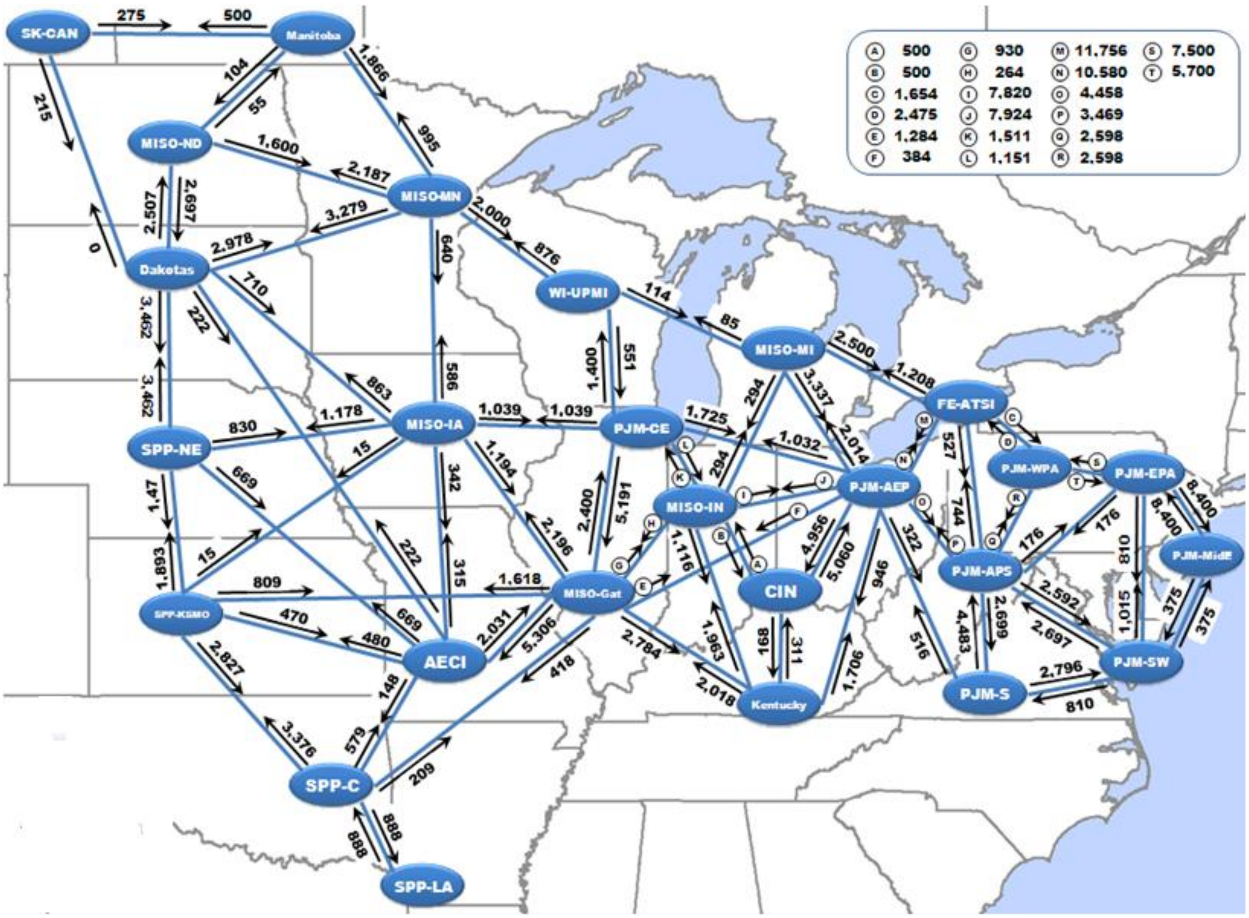


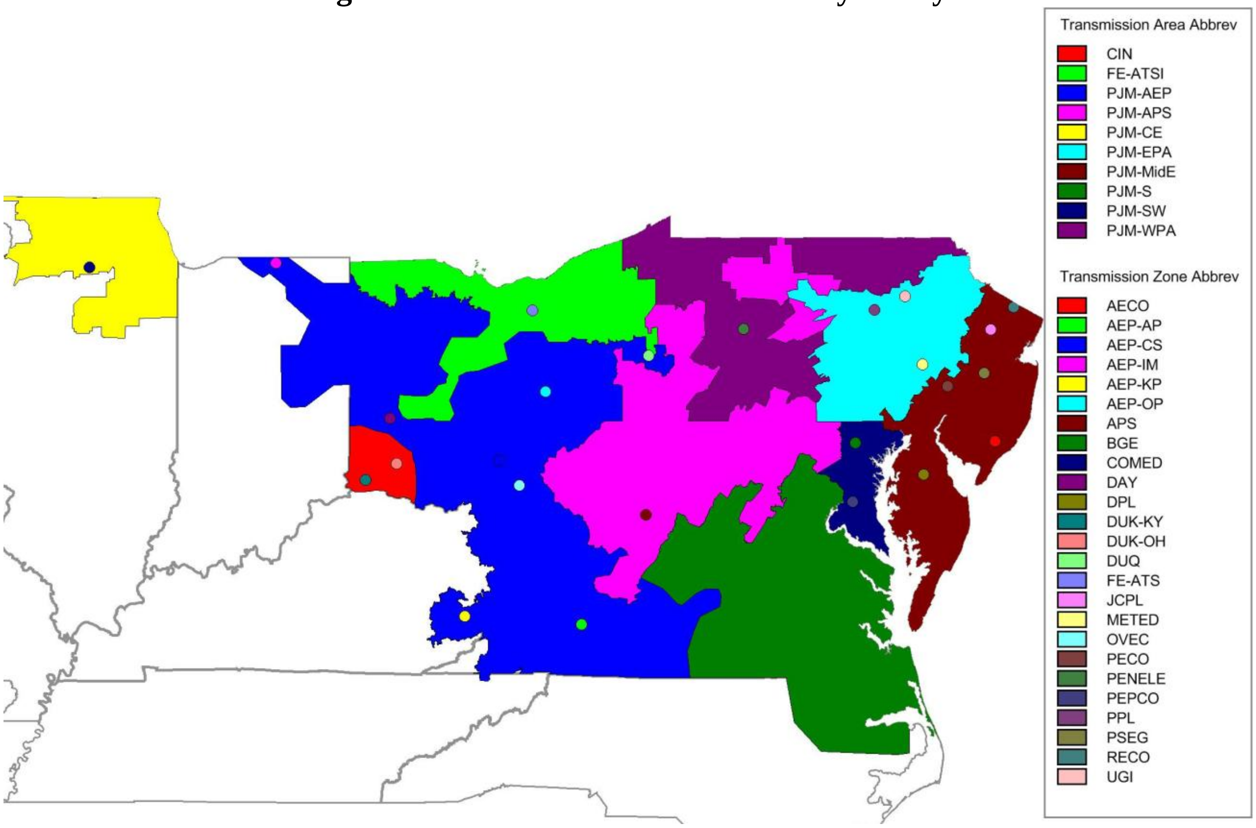
Table 3.1, below, describes the geographic areas associated with the market bubbles shown in Figure 3.1, above. Note that certain states, including Maryland, are listed within more than one market area. In those cases, different portions of the state are contained within different market areas. The market containing portions of Maryland are shown in bold type in Table 3.1.

Table 3.1
Market Topology

Market Area Name	Abbreviation	Market Area Description	Geographic Location
Cincinnati	CIN	Duke Energy Ohio and Kentucky	OH, KY
Dakotas	Dakotas	North and South Dakotas	ND, SD, IA
FirstEnergy ATSI	FE-ATSI	First Energy - ATSI	OH, PA
MISO - Gateway	MISO-Gat	S Illinois E Missouri (Gateway)	IL, MO
MISO - Indiana	MISO-IN	Cinergy + Other Indiana Utilities	OH, IN
MISO - Iowa	MISO-IA	Iowa	IA
MISO - Manitoba	Manitoba	Manitoba	MB (Canada)
MISO - Michigan	MISO-MI	Michigan Electric Coordinated Systems	MI
MISO - Minnesota	MISO-MN	Minnesota	MN, WI, ND
MISO - North Dakota	MISO-ND	MISO North Dakotas	ND
MISO - WI-UPMI	WI-UPMI	Wisconsin-Upper Michigan	MI, WI
PJM - AEP	PJM-AEP	American Electric Power	VA, OH, IN, KY
PJM - APS	**PJM-APS**	**Allegheny Power System**	**WV, MD, PA**
PJM - COMED	PJM-CE	Commonwealth Edison/Northern Illinois	IL
PJM - South	PJM-S	Dominion Virginia Power Company	VA
PJM MidAtlantic - E	**PJM-MidE**	**PJM MidAtlantic - East of East Interface**	**NJ, PA, DE, MD**
PJM MidAtlantic - East PA	PJM-EPA	PJM MidAtlantic - East Pennsylvania	PA
PJM MidAtlantic - SW	**PJM-SW**	**PJM MidAtlantic - Southwest**	**MD, DC**
PJM MidAtlantic - West PA	PJM-WPA	PJM MidAtlantic - West Pennsylvania	PA
Saskatchewan	SK-CAN	Saskatchewan Power	SK (Canada)
SPP - Central	SPP-C	Southwest Power Pool - Central Region	LA, MO, OK, TX
SPP - KSMO	SPP-KSMO	Southwest Power Pool - North	KS, MO
SPP - Louisiana	SPP-LA	Louisiana (Non-Entergy)	LA
SPP - Nebraska	SPP-NE	Nebraska	NE

Figure 3.2 below shows the PJM transmission zones and utilities within each zone.

Figure 3.2 PJM Transmission Zones by Utility



The LTER Reference Case transmission topology reflects transmission lines in place as of January 2011 plus the Trans Allegheny Interstate Line (TrAIL), which as of January 2011 had received all necessary regulatory approvals and was under construction, with completion scheduled for June 2011. TrAIL is a 500-kV line owned by FirstEnergy, and runs from Southwestern Pennsylvania to West Virginia and then to Northern Virginia, facilitating the transmission of power from west to east.

3.3 Loads

Load forecasts are a required input for the simulation models relied upon to conduct the LTER analysis. PPRP adjusted PJM's December 2010 Peak Load and Energy Forecast (released in January 2011) downward to reflect the energy and peak demand impacts of energy efficiency and peak load reduction programs in the State of Maryland, such as EmPOWER Maryland and similar programs in other PJM states.[10] The energy and demand reductions associated with EmPOWER Maryland are presented in Table 3.2 and Table 3.3.

Table 3.2
Maryland Public Service Commission EmPOWER Maryland
2015 Energy Reduction Projections

Utility	Projected Energy Reduction (MWh)
Allegheny	35,398
BGE	1,993,449
Delmarva	74,376
Pepco	348,073
SMECO	365,350
Total	2,751,238

Source: Maryland Public Service Commission.

[10] See Appendix C for a detailed discussion of the EmPOWER Maryland adjustments.

Table 3.3
Maryland Public Service Commission EmPOWER Maryland
2015 Demand Reduction Projections

Utility	Projected Demand Reduction (MW)
Allegheny	NA
BGE	1,401
Delmarva	135
Pepco	493
SMECO	141
Total	2,170

Source: Maryland Public Service Commission.
Note that Allegheny does not have a demand response program in place.

PJM states other than Maryland have also implemented energy conservation and efficiency programs. The PJM forecast was adjusted to account for these programs as well as the programs in Maryland.

PPRP also adjusted the PJM load forecast to account for the impact of Plug-in Hybrid Electric Vehicles ("PHEVs") and Battery Electric Vehicles ("BEVs"). These two vehicle types are referred to collectively as Plug-in Electric Vehicles ("PEVs") and treated as electrically equivalent with respect to energy use.[11] The estimated load impacts of PEVs are based on the following assumptions:

- Market penetration assumptions are based on Pacific Northwest National Laboratory's market penetration analysis;
- PEV energy consumption assumptions are based on 4 to 5 miles per kWh;
- Average vehicle life is 10 years;
- PEV driving assumptions are based on average use of 30 miles per day;

[11] See Appendix D for a detailed discussion of the PEV adjustment.

- Required charge of 7 kWh per day;
- PEV charging assumptions are based on Level 2 home chargers – utility managed charging technology spreads loads evenly over charging hours with 90 percent of PEVs charged during off-peak hours and 10 percent during on-peak hours.

Table 3.4, below, lists the assumed weekday peak and off-peak load impacts of increased numbers of PEVs for the PJM region as a whole and separately for the State of Maryland.

Table 3.4
Total Weekday Hourly Demand from PEVs in Maryland and PJM (MW)

2020	Maryland	Total On-Peak	3.5
		Total Off-Peak	63
	PJM	Total On-Peak	33
		Total Off-Peak	589
2030	Maryland	Total On-Peak	23.6
		Total Off-Peak	424
	PJM	Total On-Peak	222
		Total Off-Peak	4,003

Table 3.5, below, summarizes the PJM December 2010 load forecast and the adjusted forecast used in the LTER Reference Case.

Table 3.5
PJM & LTER Reference Case Forecasts

	Peak Demand (MW)		Energy (GWh)	
Year	December 2010 PJM Forecast*	LTER Reference Case	December 2010 PJM Forecast*	LTER Reference Case
2010	152,690	159,354	795,219	814,219
2011	154,383	158,677	820,128	814,632
2012	158,603	162,256	842,634	832,659
2013	162,489	165,463	860,521	845,814
2014	164,772	167,106	874,144	855,582
2015	166,506	168,411	883,516	861,334
2016	167,847	169,180	894,032	868,929
2017	169,443	169,953	899,413	871,671
2018	171,067	171,350	908,129	877,644
2019	172,780	172,822	916,084	884,242
2020	174,458	174,571	928,271	895,297
2021	176,060	175,969	933,927	901,668
2022	177,416	177,443	941,880	910,277
2023	178,810	178,478	948,525	917,808
2024	180,087	180,128	957,423	927,429
2025	181,443	181,605	962,236	933,465
2026	182,904	183,177	969,596	942,313
2027	184,289	184,709	976,723	950,813
2028	185,685	186,256	983,903	959,498
2029	187,092	187,884	991,135	968,333
2030	188,509	189,469	998,421	977,293
Average Annual Growth Rates				
2010 - 2020	1.34%	0.92%	1.56%	0.95%
2020 - 2030	0.78%	0.82%	0.73%	0.88%
2010 - 2030	1.06%	0.87%	1.14%	0.92%

*PJM's December 2010 Forecast extends only to 2025. For years 2026 through 2030, the forecast values were obtained through extrapolation.

3.4 Generation Unit Operational and Cost Characteristics for Fossil Fuel Generation

Generation unit operational and cost characteristics are critical assumptions because they determine how much it will cost to generate electricity. The operational characteristic assumptions include fuel costs and fixed and variable O&M expenses. Fuel prices are among the most important assumptions in the LTER because they determine which power plants operate, the price of electricity in each market bubble (this price depends on the marginal unit in each bubble), and the types of new power plants (e.g., natural gas, nuclear) that are constructed to meet growing demand as well as to replace generation from retiring plants.

Figure 3.3, on page 46, plots the base, high, and low gas price projections for the Henry Hub, which is the most liquid natural gas hub in the U.S.[12] The Henry Hub natural gas price is adjusted upward in the model simulations to reflect the costs necessary to transport gas from the Henry Hub to the geographic region where each generator is located. This methodology, which relies on Henry Hub basis point differentials, is standard in the industry. The Henry Hub natural gas price forecast (base, high, and low) is provided in tabular format in Table 3.6, below.

[12] Henry Hub is the most important and most liquid trading hub for natural gas in the U.S. and the delivery point for NYMEX natural gas futures contracts. Virtually every natural gas forecast produced in the industry, including the Ventyx forecast and Energy Information Administration's *Annual Energy Outlook*, is based in part on Henry Hub prices. The Henry Hub is physically located in Louisiana.

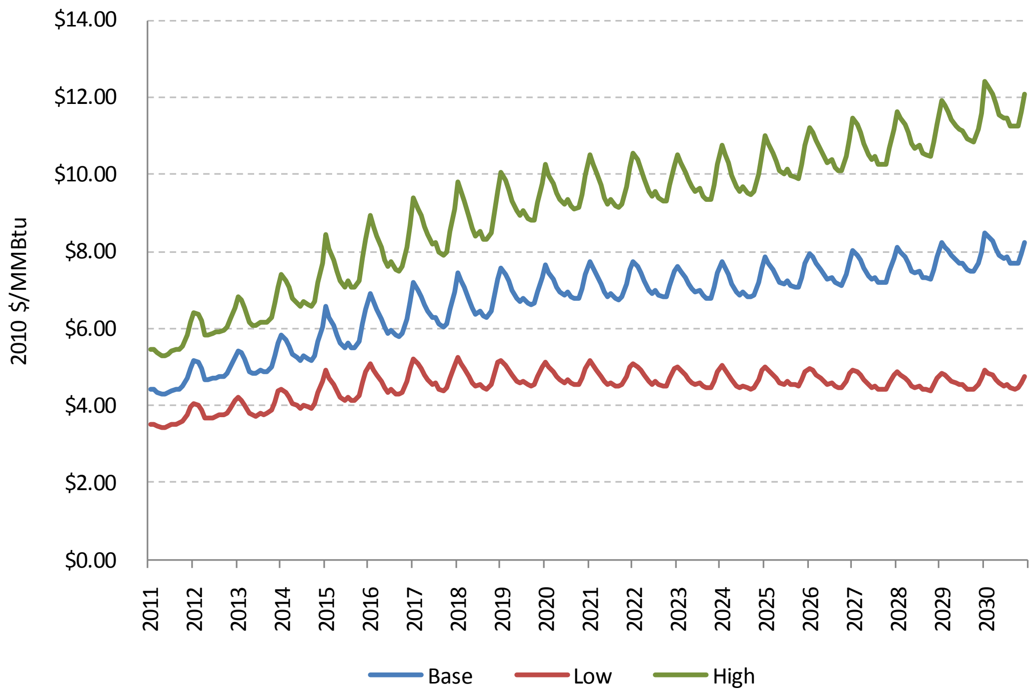
Table 3.6
Henry Hub Price Average and Maximum Monthly Prices
(2010 $/mmBtu)

Year	Low		Base		High	
	Average	Max	Average	Max	Average	Max
2011	3.56	3.97	4.46	4.98	5.50	6.15
2012	3.84	4.12	4.89	5.24	6.09	6.53
2013	3.94	4.36	5.09	5.63	6.41	7.09
2014	4.16	4.61	5.46	6.05	6.93	7.69
2015	4.43	4.93	5.90	6.57	7.57	8.42
2016	4.59	5.09	6.22	6.90	8.05	8.93
2017	4.74	5.21	6.53	7.18	8.53	9.37
2018	4.75	5.24	6.75	7.44	8.90	9.81
2019	4.76	5.16	6.98	7.57	9.28	10.07
2020	4.75	5.12	7.09	7.64	9.52	10.26
2021	4.74	5.15	7.13	7.75	9.66	10.49
2022	4.73	5.10	7.16	7.72	9.78	10.55
2023	4.67	5.00	7.12	7.63	9.82	10.52
2024	4.66	5.04	7.16	7.75	9.95	10.77
2025	4.70	5.01	7.36	7.86	10.32	11.02
2026	4.67	4.97	7.46	7.94	10.55	11.23
2027	4.61	4.93	7.52	8.03	10.72	11.45
2028	4.58	4.87	7.61	8.09	10.95	11.63
2029	4.60	4.86	7.80	8.23	11.30	11.93
2030	4.63	4.90	8.01	8.48	11.70	12.39

Source: Ventyx's Fall 2010 Reference Case

The LTER Reference Case relies on the base natural gas forecast shown as the middle line in Figure 3.3, below, and the Base/Average figures shown in Table 3.6, above. The high and low cases are used in alternative scenarios and discussed in subsequent chapters of this report. They are included in Figure 3.3 and Table 3.6 to provide perspective regarding the degree of uncertainty surrounding future natural gas prices.

Figure 3.3 Natural Gas Forecast of the Henry Hub Price



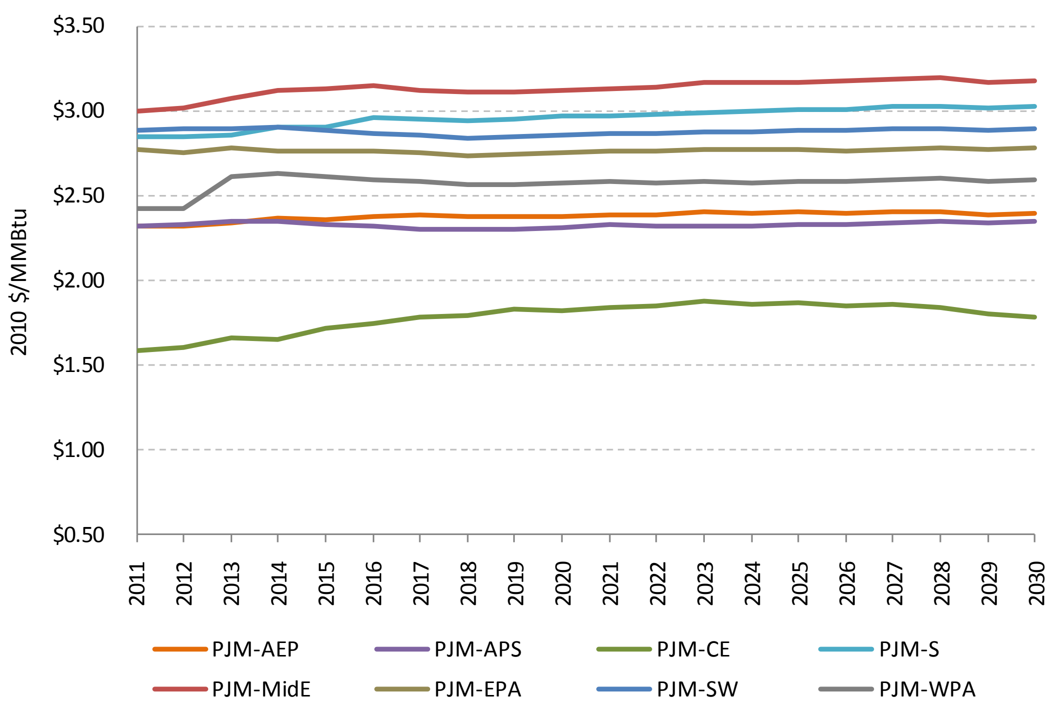
Source: Ventyx's Fall 2010 Reference Case

The base gas price forecast shown in Figure 3.3 above (and numerically presented in Table 3.6) is generally consistent with the Energy Information Administration's 2010 *Annual Energy Outlook* ("AEO") reference case. The high and low gas price cases, however, differ markedly from the 2010 AEO high and low gas price projections, which we judge to be too similar to the LTER Reference Case to adequately capture the range of uncertainty associated with future gas prices. The forecasted gas prices shown in Figure 3.3 for the high case exceed the 2010 AEO high case and the Figure 3.3 low case projections are below the 2010 AEO low case.

This most recent AEO natural gas price projections released in December 2010 as part of EIA's preview of the 2011 AEO are substantially below EIA's projection in the 2010 AEO. The principal reason underlying the lower 2011 projection is the assumed abundance of natural gas obtained from Marcellus shale. To the extent that environmental concerns related to extraction of natural gas from Marcellus shale inhibit future natural gas production, or the costs related to the mitigation of environmental damage associated with the extraction of natural gas prove to be higher than expected, the EIA projections would understate future natural gas prices, other factors equal.

Figure 3.4, below, plots coal prices by PJM area for various regions in PJM. These projections are based on detailed information about individual generating units, and these data are used to produce burner-tip prices at each coal-fired power plant based on the specific type of coal (e.g., Central Appalachia or Illinois Basin) that each generator purchases. The coal prices represented in Figure 3.4 are shown numerically in Table 3.7, which follows.

Figure 3.4 Coal Price Forecast by PJM Area



Source: Ventyx's Fall 2010 Reference Case

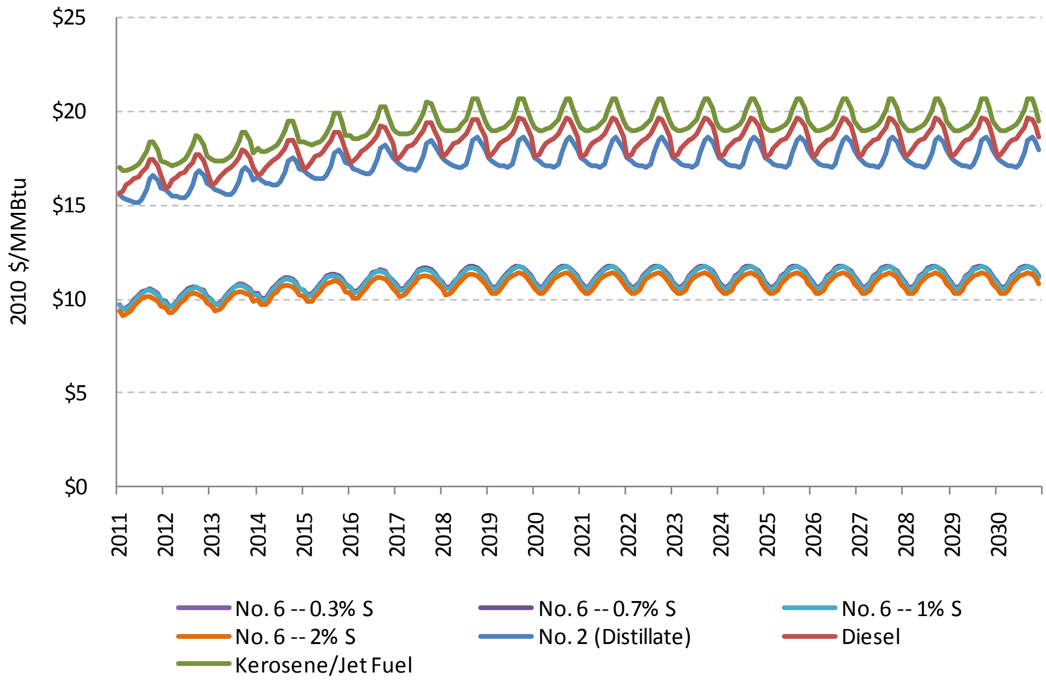
Table 3.7
Average Delivered Coal Price Forecast (2010 $/mmBtu)

Year	PJM-AEP	PJM-APS	PJM-CE	PJM-S	PJM-MidE	PJM-EPA	PJM-SW	PJM-WPA
2011	2.32	2.32	1.58	2.85	3.00	2.77	2.89	2.42
2012	2.32	2.33	1.60	2.85	3.02	2.75	2.89	2.43
2013	2.34	2.35	1.66	2.86	3.07	2.79	2.90	2.61
2014	2.36	2.35	1.65	2.91	3.12	2.76	2.90	2.63
2015	2.36	2.32	1.71	2.91	3.13	2.77	2.88	2.61
2016	2.38	2.32	1.74	2.96	3.15	2.76	2.86	2.60
2017	2.38	2.30	1.78	2.95	3.12	2.75	2.86	2.58
2018	2.37	2.30	1.79	2.94	3.11	2.73	2.84	2.57
2019	2.38	2.30	1.83	2.95	3.11	2.75	2.85	2.56
2020	2.37	2.31	1.82	2.97	3.12	2.75	2.86	2.57
2021	2.39	2.32	1.84	2.97	3.13	2.77	2.87	2.58
2022	2.39	2.32	1.84	2.98	3.14	2.76	2.86	2.57
2023	2.40	2.32	1.88	2.99	3.16	2.77	2.88	2.58
2024	2.39	2.32	1.86	2.99	3.16	2.77	2.87	2.58
2025	2.40	2.33	1.86	3.00	3.17	2.77	2.89	2.58
2026	2.40	2.33	1.85	3.01	3.18	2.76	2.88	2.58
2027	2.41	2.34	1.85	3.02	3.19	2.77	2.90	2.60
2028	2.40	2.35	1.84	3.03	3.19	2.78	2.90	2.60
2029	2.38	2.34	1.80	3.02	3.17	2.77	2.88	2.58
2030	2.40	2.35	1.78	3.03	3.18	2.78	2.90	2.59

Source: Ventyx's Fall 2010 Reference Case.

Fuel oil projections are presented in Figure 3.5 and in Table 3.8, both below. Nuclear fuel price projections are shown in Table 3.9, which follows.

Figure 3.5 Fuel Oil Forecast



Source: Ventyx's Fall 2010 Reference Case

Table 3.8
Average Annual Fuel Oil Price (2010 $/mmBtu)

Year	Average of No. 6 – 0.3% S	Average of No. 6 – 0.7% S	Average of No. 6 – 1% S	Average of No. 6 – 2% S	Average of No. 2 (Distillate)	Average of Kerosene/ Jet Fuel
2011	10.06	10.03	10.00	9.71	15.69	17.45
2012	10.22	10.18	10.15	9.85	15.94	17.72
2013	10.33	10.30	10.27	9.97	16.13	17.93
2014	10.65	10.61	10.58	10.27	16.64	18.49
2015	10.86	10.82	10.79	10.48	16.98	18.87
2016	11.05	11.00	10.97	10.65	17.27	19.19
2017	11.18	11.14	11.10	10.78	17.49	19.42
2018 - 2030	11.28	11.23	11.20	10.88	17.64	19.59

Source: Ventyx's Fall 2010 Reference Case.

Table 3.9
Nuclear Fuel Prices

Year	Price (2010 $/mmBtu)
2011	0.75
2012	0.78
2013	0.79
2014	0.78
2015	0.78
2016	0.80
2017	0.81
2018	0.80
2019	0.79
2020	0.77
2021	0.74
2022	0.73
2023	0.71
2024	0.70
2025	0.68
2026	0.66
2027	0.65
2028	0.65
2029	0.65
2030	0.66

Source: Ventyx's Fall 2010 Reference Case.

The Ventyx model "builds" new generation when it is economic to do so based on market conditions and the cost of constructing new facilities. Table 3.10, below, contains detailed information on the capital, variable O&M, and fixed O&M costs associated with new generation technologies. The financial parameters needed to guide investment decisions are presented in Table 3.11, which follows.

Table 3.10
Cost and Operational Assumptions of New Generation Over the Forecast Period

Unit Type		Summer Capacity (MW)	Capacity Factor	Full-Load Heat Rate HHV (Btu/kWh)	Fixed O&M (2010 $/kW-yr)	Variable O&M (2010 $/MWh)	Forced Outage Rate (%)	Maintenance Outage Rate (MOR) (%)	Overnight Construction Cost (2010 $/kW)
Pulverized Coal Steam Turbine	PC	800		8,600	$26.95	$4.00	6.0%	6.5%	$2,660
Combustion Gas Turbine	GT	160		10,500	$12.60	$3.75	3.6%	4.1%	$660
Aero derivative Gas Turbine	AD	90		9,000	$10.95	$3.30	3.6%	4.1%	$1,020
Combined Cycle Natural Gas	CCNG	450		6,800	$13.00	$2.15	5.5%	4.1%	$970
Integrated Coal Gasification Combined Cycle	IG	600		8,300	$47.30	$4.65	6.0%	6.5%	$3,360
Nuclear	NU	1,000		10,400	$70.55	$0.55	3.8%	6.1%	$5,870
Pulverized Coal Steam Turbine with Carbon Capture and Sequestration	PC-CCS	540		11,200	$32.15	$6.15	7.0%	7.5%	$5,089
Combined Cycle Natural Gas with Carbon Capture and Sequestration	CCNG-CCS	310		8,900	$22.10	$3.15	6.5%	5.0%	$2,134
Integrated Coal Gasification CCNG w\ Carbon Capture and Sequestration	IG-CCS	410		10,800	$56.40	$7.10	7.0%	7.5%	$5,649
Geothermal Steam Turbine	GE	10		10,000	$169.85	$0.00	20.0%	0.0%	$1,900
Landfill Gas	LG	10		10,000	$119.72	$0.01	30.0%	0.0%	$2,550
Biomass	BM	10		10,000	$70.23	$7.21	30.0%	0.0%	$3,300
Photovoltaic	PV	10	18%	-	$12.55	$0.00	0.0%	0.0%	$5,000*
Wind Turbine - On Shore (2010)	WT	10	30%	-	$29.55	$0.00	0.0%	0.0%	$2,200
Wind Turbine - On-Shore (2011-2030)			30%		$29.55	$0.00			$1,800
Wind Turbine - Off-Shore			40%		$73.88	$0.00			$4,260

*Declines linearly to $4,000/kW in 2030.
Source: Ventyx, PPRP

Table 3.11
Financial Assumptions

	Debt	Equity
Debt/Equity Ratio	50%	50%
Cost rate	7%	12%
Effective Tax Rate	40.20%	
Inflation Rate	2.5%	

Note that in Table 3.10, capacity factors are shown only for solar photovoltaic and wind power projects, the reason for which is that the model dispatches other technologies based on least-cost and reliability criteria. The intermittent resources (solar and wind) are run when available, with annual capacity factors shown in Table 3.10. The majority of the data shown in Table 3.10 is from Ventyx, although the data for renewable energy sources were developed by PPRP and detailed in Appendix E.

3.5 Environmental Policies and the Renewable Energy Portfolio Standard

3.5.1 U.S. Environmental Protection Agency Regulations

The LTER Reference Case includes regulations for which the U.S. Environmental Protection Agency ("EPA") has issued a final rule (for example, the Tailoring Rule); however, recently issued proposed rules are not part of the LTER Reference Case. At the request of several stakeholders, PPRP is running an additional alternative scenario that will include the proposed EPA regulations. The input assumptions for EPA regulations included in the LTER Reference Case are provided below.

1. Clean Air Transport Rule for SO_2 and NO_x

   As described in Chapter 2, Ventyx uses a proprietary emission forecast model to simulate emission control decisions and results simultaneously in the three cap-and-trade markets (SO_2, NO_x annual, and NO_x ozone season) that comprise the Clean Air Transport Rule ("CATR"). The capital and operating costs of SCRs and FGDs are unit specific, based on Ventyx's Velocity Suite engineering estimates. As an example, average FGDs add $1.20 per MWh to variable O&M and about $34 per kW-year to fixed O&M and capital costs. (Note that on July 6, 2011, EPA issued the Cross-State Air Pollution Rule ("CSAPR"). PPRP will evaluate the differences between CSAPR and CATR and will address these differences in the final draft report.)

2. Tailoring Rule and New Source Performance Standards

   The Ventyx model includes implementation of the Tailoring Rule for greenhouse gas. This was added to the Ventyx model by imposing constraints on coal facilities. Ventyx assumes the Tailoring Rule will effectively prohibit construction of or major modifications to coal units without CO_2 controls. The carbon capture and storage technology is an added capital cost to new coal units of approximately $2,400 per kW (2010$). This assumption also results in compliance with the New Source Performance Standards with respect to coal plants. Though the installation of SCR's and FGD's may trigger NSPS for CO_2, the additional requirements would not significantly affect plant retirement decisions. All new natural gas plants built by the model are high-efficiency units that incorporate state-of-the art emissions controls and therefore meet the Tailoring Rule and New Source Performance Standards requirements.

3.5.2 Renewable Energy Portfolio Standard

Maryland's Renewable Energy Portfolio Standard ("RPS") has undergone modification several times since its enactment in 2004. These modifications have included: (1) reducing the scope of the geographical area for eligible renewables, (2) establishing a separate requirement for solar photovoltaic energy, and (3) changing the annual solar requirements and solar alternative compliance payments. A full discussion of the Maryland RPS is contained in Appendix E. Table 3.12, below, summarizes the percentage renewable requirements of Maryland's RPS.

Table 3.12
Percentages of Renewable Energy Required by Maryland's RPS

Year	Tier 1 Solar (Percent)[1]	Tier 1 Non-Solar (Percent)	Tier 2 (Percent)[2]	Total (Percent)
2006	--	1.0	2.5	3.5
2007	--	1.0	2.5	3.5
2008	0.005	2.0	2.5	4.505
2009	0.01	2.0	2.5	4.51
2010	0.025	3.0	2.5	5.525
2011	0.05	4.95	2.5	7.50
2012	0.10	6.4	2.5	9.00
2013	0.20	8.0	2.5	10.7
2014	0.30	10.00	2.5	12.8
2015	0.40	10.10	2.5	13.0
2016	0.50	12.20	2.5	15.2
2017	0.55	12.55	2.5	15.6
2018	0.90	14.9	2.5	18.3
2019	1.2	16.2	--	17.4
2020	1.5	16.5	--	18.0
2021	1.85	16.85	--	18.7
2022 (to 2030)	2.0	18.0	--	20.0

[1] Solar requirement started in compliance year 2008.
[2] Tier 2 requirement sunsets at the end of 2018.

Table 3.13, below, presents the geographic restrictions on Maryland-eligible renewable resources and also provides the costs of alternative compliance payments, which can be used by load serving entities in lieu of satisfying the RPS with the purchase of Renewable Energy Certificates ("RECs").

Table 3.13
Maryland RPS Geographical Restrictions and Alternative Compliance Payments

Geographical Restrictions	Alternative Compliance Payments
Beginning January 1, 2011, renewable energy generation must be located (1) in the PJM region only, or (2) in a control area that is adjacent to the PJM region if the electricity is delivered into the PJM region. Solar must come from within the State.[1]	Tier 1 – \$20/MWh for non-solar shortfalls through 2018. Increases to \$40/MWh for 2019 and later. Tier 2 – \$15/MWh. Solar – \$400/MWh in 2009 through 2014. Declines to \$350/MWh for 2015-2016, and then continues to decline bi-annually until it reaches \$50/MWh by 2023 and remains at that level through 2030. For Tier 1 shortfalls for industrial process load: \$5/MWh in 2009/10; \$4/MWh in 2011/12; \$3/MWh in 2013/14; \$2.5/MWh in 2015/16; and \$2/MWh in 2017 and later; no fee for Tier 2 shortfalls for industrial process load.

[1]The Maryland RPS statute allows for solar requirements to be met with out-of-state resources through December 2011 if there are insufficient resources located within the State.

Tier 1 solar energy resources in Maryland currently generate approximately 8 GWh of electricity per year. Solar electricity output is expected to increase to 720 GWh by 2022. Development of several large utility-scale solar projects will produce sufficient electricity to meet the Tier 1 Solar RPS in the short term (through 2018). However, while a significant amount of new solar capacity is assumed to be installed, the LTER assumes that only 50 percent of the Tier 1 solar requirement will be met by 2022. Thus the input assumption is that there is sufficient solar capacity to meet the Maryland RPS through 2018. For years after 2018, a portion of the solar power requirement is assumed to be satisfied through Alternative Compliance Payments.

Tier 1 non-solar energy resources in PJM currently generate approximately 20,100 GWh of electricity per year, which is more than enough to supply the regional 2010 Tier 1 non-solar renewable energy requirements established in Maryland and those of the other PJM states with renewable portfolio standards. Development of Tier 1 non-solar renewable resources is assumed to keep pace with demand so that the region's RPS requirements are fully met throughout the study period.

Tier 2 energy resources in PJM currently generate approximately 18,000 GWh of electricity per year, which is more than enough to supply the regional Tier 2 renewable energy requirements established in Maryland and those of the other PJM states with similar renewable energy portfolio standards. Very little new Tier 2 generation is required to meet the regional requirements throughout the study period.

3.5.3 Regional Greenhouse Gas Initiative

Maryland is a member of the Regional Greenhouse Gas Initiative ("RGGI"), along with nine other mid-Atlantic and northeastern states. The purpose of RGGI is to limit the amount of CO_2 that can be emitted from fossil fuel power plants in the member states up to an aggregate cap. Power plants in Maryland adhere to the RGGI requirements through the purchase of emission allowances, which are auctioned by each participating state. Power plants within one state, however, may purchase allowances issued by another RGGI state as a means of compliance. Consequently, the CO_2 budget amount for any one state does not represent a hard cap for the respective state, although the aggregate allowances of all states within RGGI represent a hard cap.

RGGI sets a minimum price for allowances; allowance prices may exceed the minimum but cannot drop below the minimum. For the past several years, the price of RGGI allowances has been at the floor price, currently set at $1.89 per ton of CO_2 emissions. The floor price increases each year at the rate of inflation. The LTER Reference Case assumption is that RGGI allowance prices remain constant at the floor price (plus inflation) throughout the study period. There is a great deal of uncertainty with respect to what will happen with RGGI. Several states have considered (or are considering) withdrawing from the program and at the time the analysis was conducted, no agreement had been made regarding extending RGGI beyond 2019. In the last several years CO_2 emissions in RGGI states have dropped significantly and were about 30 percent below the 2010 RGGI budget. RGGI-covered entities can source allowances throughout the RGGI region and are also able to meet a portion of their requirements through off-sets, making Maryland-specific compliance characteristics difficult to predict. Given the uncertainty surrounding RGGI, both with respect to the continuation of the program and how Maryland covered entities will choose to meet the requirements, the LTER models RGGI allowance prices as a constant rather than attempting to impose any particular future policy decisions on the analysis.

The initial Maryland RGGI budget is set at 37,503,983 CO_2 allowances. This reduces by 2.5 percent per year to a total of 10 percent in reductions by 2018. Current Maryland policy includes a set-aside of 3,465,101 allowances for the Sparrows Point Steel Mill and the NewPage Luke Paper Mill. The RGGI budget shown in the results sections of this report is adjusted to reflect the set-aside. Table 3.14 shows the unadjusted and adjusted RGGI budget.

Table 3.14
Maryland RGGI CO_2 Allowance Budget (tons)

Year	Unadjusted RGGI Budget	Adjusted RGGI Budget
2009-2014	37,503,983	34,038,882
2015	36,566,383	33,101,282
2016	35,628,783	32,163,682
2017	34,691,183	31,226,082
2018+	33,753,583	30,288,482

3.5.4 Emissions

Maryland's Healthy Air Act ("HAA") limits the emissions of NO_x, SO_2, and mercury from Maryland coal plants. Under the HAA, emission limits are set for each plant, but owners of multiple plants can meet the requirement aggregated over all of their affected plants in the state. The relevant emissions from affected plants in the LTER Reference Case, along with relevant emissions from affected plants in the alternative scenarios, comply with the limitations contained in the HAA. The emissions rates for HAA plants were set at the plant level, based on the actual emissions reported for 2010 from plants that had already installed the necessary NO_x and SO_2 control systems. For the plants that were still in the process of installing control equipment, estimates on achievable emissions rates were calculated based on the rates from the plants with existing control equipment. Mercury emissions rates were based on the actual reported rates for all plants in 2010 and are well below the HAA limits. The following adjustments were made with respect to plants that did not have a full set of data accounting for their installation of control technologies:

- CP Crane Unit 2's SO_2 rate was reduced to the same as Unit 1's actual rate to reflect the switch to Powder River Basin low sulfur coal.
- The SO_2 rate for Dickerson Unit 2 was adjusted to match the other two Dickerson Units, as all three units have the same control technology.
- All units with selective catalytic converter (SCR) technology were adjusted to a NO_x emissions rate appropriate to that technology. According to a report by the U.S. DOE, SCR provides emissions rates as low as 0.05 lbs/MMBTU. This rate is applied to Brandon Shores 1 & 2, Chalk Point 1, and Wagner 3.
- Morgantown had NO_x emissions rates lower than the DOE report, so the actual rates were applied.

- For those units with selective non-catalytic reduction (SNCR) systems, Dickerson was used as a proxy since the units had reasonable operating hours and a very consistent control rate across all three units.

Table 3.15 lists the emissions rates applied to the Maryland HAA plants.

Table 3.15
Maryland HAA Plant Emissions Rates (lbs/mmBTU)

Facility	SO_2	NO_x	Mercury
Brandon Shores Unit 1	0.03299	0.05500	0.00000076
Brandon Shores Unit 2	0.04999	0.05500	0.00000076
Chalk Point Unit 1	0.11745	0.05500	0.00000045
Chalk Point Unit 2	0.11755	0.16802	0.00000045
C P Crane Unit 1	0.50095	0.26100	0.00000074
C P Crane Unit 2	0.50095	0.26100	0.00000074
Dickerson Unit 1	0.17994	0.26107	0.00000042
Dickerson Unit 2	0.18007	0.26095	0.00000042
Dickerson Unit 3	0.17994	0.26202	0.00000042
Herbert A Wagner Unit 2	1.17618	0.26100	0.00000166
Herbert A Wagner Unit 3	0.99542	0.05500	0.00000166
Morgantown Unit 1	0.13680	0.04800	0.00000023
Morgantown Unit 2	0.12910	0.04099	0.00000023

The Ventyx model reports total emissions at the plant-level and therefore captures all in-state emissions, which are reported in the results as being from Maryland. Carbon dioxide emissions are also calculated at the plant-level and therefore can be reported at the state-level. The same emissions rates were applied for each alternative scenario.

4. LTER REFERENCE CASE RESULTS

4.1 Introduction

As noted in Chapter 3 of this report, the LTER Reference Case is based on what could be termed a "business as usual" set of assumptions. It incorporates existing legislation regarding renewable energy development, the existing PJM backbone transmission system,[13] existing power plants (including those currently under construction), and a forecast of energy and peak demand consistent with PJM's December 2010 forecast.[14] New power plants are added as peak demand or energy requirements dictate on the basis of least cost. Finally, plants can retire for either economic reasons or based on age. New plants may be required to replace the generation formerly supplied by retiring plants.

4.2 Plant Additions and Retirements

Table 4.1, below, presents PJM plants classified as "planned construction," and includes the on-line date, the state in which the plant is to be located, the plant capacity, and the plant type/fuel. To be considered "planned construction," a plant must have obtained all necessary air permits and have begun construction. The plants shown in Table 4.1 are included not only in the LTER Reference Case, but in all other scenarios.

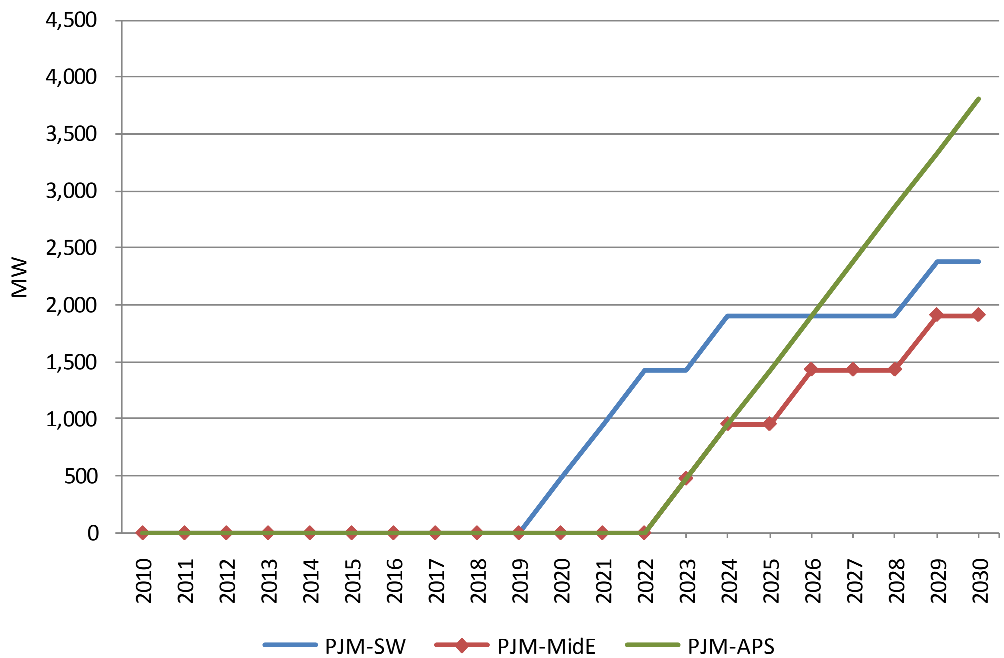
[13] As noted in Chapter 3, the Trans-Allegheny Interstate Line ("TrAIL") is assumed to be a part of the PJM backbone system starting in June 2011.
[14] Chapter 3 documents the modifications made to the PJM baseline forecast to incorporate energy efficiency and conservation savings, increasing saturation of plug-in electric vehicles, demand response, and AMI effects.

Table 4.1
LTER Reference Case "Planned" Capacity Additions

Installation Date	Unit Name	State	Fuel Type	Name Plate Capacity (MW)
12/1/2010	South Point Biomass	OH	Biomass	200
9/1/2010	Beech Rid	WV	Wind	16.5
9/1/2010	Laurel Mt	WV	Wind	132.5
10/1/2010	Roth Rock	MD	Wind	40
12/1/2010	Criterion	MD	Wind	70
9/1/2010	Crescent	IL	Wind	57.8
10/1/2010	Top Crop	IL	Wind	198
12/1/2010	Big Sky Wind	IL	Wind	239.4
12/1/2010	GSG Wind	IL	Wind	120
10/1/2010	Crystal Lake	PA	Wind	18
12/1/2010	Delta Power Plant	PA	Gas	556
10/1/2010	Yardville Solar	NJ	Solar	5.1
12/1/2010	DowJones Solar	NJ	Solar	4.1
12/1/2010	Linden Solar	NJ	Solar	3.6
9/1/2010	Old Dominion Landfill Project	VA	Landfill Gas	8
9/1/2010	Highland	VA	Wind	38
12/1/2010	Henrico County Landfill	VA	Landfill Gas	4
12/1/2010	Laurel Hi	PA	Wind	70.5
9/1/2011	SunCoke Energy Project	OH	Waste Heat	57
1/1/2011	Fremont Energy	OH	Gas	703
10/1/2011	HardinNorth	OH	Wind	50
6/1/2011	Buckeye Wind	OH	Wind	108
10/1/2011	Hardin Wind	OH	Wind	300
3/1/2011	Longview Power	WV	Coal	807.5
12/1/2011	Pinnacle	WV	Wind	55
3/1/2011	Robbins Community Power	IL	Biomass	55
6/1/2011	Nelson EC	IL	Gas	573
10/1/2011	Twin Grove 1	IL	Wind	200.5
12/1/2011	GSF Wind	IL	Wind	120
12/1/2011	Lancaster	IL	Wind	62
12/1/2011	White Oak	IL	Wind	136.5
6/1/2011	Bear Garden	VA	Gas	580
6/1/2011	Prince William County Landfill	VA	Landfill Gas	4
7/1/2012	Virginia City Hybrid Energy Center	VA	Coal	668
12/1/2012	Black Mountain Wind	VA	Wind	150
10/1/2012	Twin Grove 2	IL	Wind	200.5
6/1/2012	Economic Power & Steam	NC	Biomass	5.4

Figure 4.1 shows the cumulative additions to generating capacity added by the models based on least-cost satisfaction of load and reliability requirements for the PJM-SW zone, the PJM-MidE zone, and the PJM-APS zone. PJM as a whole adds a total of 30,101 MW of new natural gas capacity over the study period. All power plants added by the model are either natural gas combined cycle plants or natural gas combustion turbines.[15] This is not a modeling restriction; it is a result based on least-cost system additions.

Figure 4.1 Generic Natural Gas Capacity Additions in LTER Reference Case



All plants added in the PJM-SW zone are assumed to be constructed in Maryland. The PJM-SW zone includes only Central and Southern Maryland as well as the District of Columbia. Plants constructed in PJM-MidE and PJM-APS are assigned to the relevant zone and not to a

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[15] The model adds discrete natural gas power plants. The effective capacity of each natural gas combined cycle plant is 450 MW in summer and 490 MW in winter. Throughout this report, CCNG capacity additions are reported at the average annual effective capacity of 477 MW per plant.

particular state. PJM-MidE includes Maryland's Eastern Shore and also Delaware, New Jersey, and the eastern-most portion of Pennsylvania. PJM-APS includes Western Maryland, Western Pennsylvania, and West Virginia. Consequently, assigning any particular plant to be constructed in Maryland for either the PJM-MidE zone or the PJM-APS zone would be arbitrary.

As shown in Figure 4.1, none of the zones in which portions of Maryland are located requires new resources until at least 2020. Existing generating capacities combined with the import/export capacities of the existing transmission system (including TrAIL) adequately meets the load and reliability requirements established by PJM. We note, however, that to the extent the energy efficiency and conservation savings do not materialize as reflected in the model input assumptions, or demand response is significantly below assumed levels, a need may arise for new generating capacity earlier than 2020. Additionally, if load growth is more rapid than projected, generating capacity additions will be required at an earlier date. The implications of shortfalls in energy efficiency and conservation savings, lower levels of demand response, and more rapid growth in load are captured through the alternative scenarios which are based on high energy and peak demand requirements relative to the LTER Reference Case. These alternative scenarios are addressed in subsequent chapters.

Other factors may also affect the need for new generation capacity, including new environmental regulations geared towards reducing power plant emissions. The implications of new regulations recently proposed by the U.S. Environmental Protection Agency ("EPA") are addressed through an alternative scenario in Chapter 12.

Through 2030, in PJM-SW, five generic (477-MW) combined cycle plants are constructed (the first in 2020); in PJM-APS, which includes Western Maryland, eight combined cycle units are constructed, with the first entering service in 2023; and in PJM-MidE, which includes the Eastern Shore, a total of four 477-MW plants are constructed with the first brought on-line in 2023.

As noted in the LTER Reference Case assumptions discussion, Maryland and other PJM states are assumed to fully meet the non-solar portion of the RPS through RECs purchases rather than Alternative Compliance Payments ("ACPs"). Table 4.2, below, shows the cumulative renewable energy capacity additions built into the modeling in order to meet RPS requirements for PJM-SW and PJM as a whole.[16] Through 2030, a total of 792 MW of renewable capacity is added in Maryland: 498 MW of solar capacity and 294 MW of non-solar renewable energy capacity. In PJM as a whole, a total of 16,256 MW of renewable capacity (2,367 MW of solar capacity and 13,889 MW of non-solar renewable capacity) is added to meet the RPS requirements for the aggregate of PJM states.

Table 4.2
LTER Reference Case Cumulative Renewable Capacity Additions (MW)

Year	Maryland	PJM Total
2011	124	1,105
2012	424	2,222
2013	495	4,338
2014	541	4,722
2015	588	5,402
2020	739	11,051
2025	766	14,711
2030	792	16,256

[16] The RPS discussion does not include the Maryland Tier 2 requirement as this sunsets in 2018.

Plant retirements occur for economic reasons or because of the age of the plant. In the LTER Reference Case, economic retirements are minimal, with a total of 315 MW of PJM generating capacity retiring due to economic reasons throughout the study period: 241 MW in PJM-AEP and 117 MW in FE-ATSI.

Age-based retirements are significant because of the number of older generating capacity currently operating in the PJM footprint. A little over 24 GW of generation capacity retires in PJM due to age during the study period. This generation capacity retirement remains constant through all the LTER alternative scenarios with the exception of the life extension scenarios, which are predicated on delayed age-based retirements. Age-based retirements in PJM in the LTER Reference Case are shown in Table 4.3, below. The total MW of age-based retirements in PJM consists of 49 percent coal-fired facilities, 26 percent petroleum, 15 percent natural gas, and 10 percent nuclear.

Table 4.3 LTER Reference Case Age-Based Retirements in PJM

	Coal		Natural Gas		Petroleum		Nuclear*	
	MWs	Zone	MWs	Zone	MWs	Zone	MWs	Zone
2010	504.5	A, S, AP, M, CE	80.8	SW, CE	158.3	AP, M		
2011	325.2	E, M			177.7	M		
2012	606.4	A, F, M	251.4	F, M, CE	735.2	S, SW, M		
2013	814.5	A, F, AP, E, SW, M	38.5	C, M	17.2	M		
2014	182.2	A, S, SW	267.5	S, C	112	F, M		
2015	974	A, AP, E	80.8	F, M	5.7	C		
2016	264	A, F, AP	20.1	M	565.8	F, S, E, SW, M		
2017	102.7	A, F, E	102.5	A, M	512	F, S, M, CE		
2018	190.2	A, M	303.9	A, C, SW	403.7	S, C, E, M		
2019	30.2	A	303.5	A, F, C, SW, M, CE	446.9	S, E, SW, M		
2020			1410.2	F, C, W, E, M	472	S, C, E, SW, M		
2021			297.8	S, M	1620.8	A, F, C, W, E, SW, M		
2022	79.8	AP	280.5	M	541.8	F, SW, M		
2023			165.6	M	473.8	SW, M		
2024	330.4	A, F						
2025	326.7	A, E	112.9	M				
2026	514.4	A, S, C	88.2	SW				
2027	895.6	A, F, S, C, E						
2028	1161.5	A, F, S, C, AP, W, SW					583.8	M
2029	2032.7	A, F, C, CE	89.7	S	135.7	F, CE	867	CE
2030								

Legend: A: PJM-AEP, F: FirstEnergy, S: PJM-S, C: Cincinnati, M: PJM-MidE, AP: PJM-APS, W: PJM-WPA, E: PJM-EPA, SW: PJM-SW, CE: PJM-COMED

* Exelon announced the planned retirement of its Oyster Creek nuclear facility in 2019. Because the modeling work was completed prior to the Exelon announcement, the LTER identifies Oyster Creek as closing in 2028 due to plant age. The capacity of the Oyster Creek plant is equivalent to approximately 1-and-a-quarter natural gas plants and therefore the differential timing of retirement dates between the announced date and the LTER age-based date are not anticipated to result in significant differences in the results. For the additional runs related to proposed EPA regulations, the announced retirement date will be relied upon since the stated reason for the retirement relates to the EPA's 316(b) rules affecting cooling water use.

4.3 Net Energy Imports

Table 4.4, below, shows net imports of energy (total imports of energy minus total exports) for PJM-SW, PJM-APS, and PJM-MidE. As shown on Table 4.4, PJM-SW, which includes the Pepco and BGE service areas as well as the Southern Maryland Electric Cooperative ("SMECO"), remains a net importer of energy throughout the study period. Net imports represent approximately 36 percent of load in 2010, although this percentage declines slightly in the first three years of the study period. Net imports increase between 2013 and 2019 (ranging from 31 to 33 percent over the period), then decline in 2020 due to a combined cycle unit being added in that year. Four additional plants are added through 2030, and net imports settle into the 22 to 25 percent range after 2022.

Table 4.4 LTER Reference Case Net Imports (GWh)			
Year	PJM-SW	PJM-MidE	PJM-APS
2010	24,631	27,994	-8,405
2011	23,535	32,733	-13,371
2012	22,043	31,036	-14,054
2013	21,232	31,605	-14,342
2014	21,304	32,933	-13,863
2015	21,579	31,340	-13,614
2016	22,042	31,615	-12,779
2017	22,530	31,577	-11,640
2018	22,960	31,031	-11,388
2019	23,867	34,119	-10,792
2020	21,615	35,437	-10,285
2021	19,256	38,186	-9,617
2022	17,157	41,643	-8,901
2023	18,418	42,530	-10,561
2024	16,619	42,285	-12,509
2025	17,500	43,432	-14,034
2026	18,170	44,950	-15,798
2027	19,383	47,319	-16,934
2028	20,029	49,464	-18,210
2029	18,372	55,825	-19,248
2030	18,900	58,513	-21,620

Net imports to the PJM-MidE area remain relatively flat through 2018, then trend upward through the balance of the study period. The timing of the increases in net imports in PJM-MidE follows the build-out of plants within PJM – that is, net imports in PJM-MidE begin to increase in 2019, which corresponds to when the first new plants (other than those plants for which air permits have already been secured and construction begun) come on-line in PJM. While construction of new power plants occurs in PJM-MidE beginning in 2023 (see Figure 4.1 on page 62), only four combined cycle natural gas plants (477 MW each) are built in this area by 2030. Increases in load over the study period are met with a combination of new generation and higher net imports of electricity.

PJM-APS, which includes Western Maryland, remains a net exporter over the entire 20-year study period. Exports increase slightly through 2013, then decline slightly through 2022. Over the last eight years of the study period, net exports increase in response to higher power prices in other PJM areas.

4.4 Fuel Use

Generation in Maryland has primarily been fossil-fuel based, and this holds true over the study period. However, the relative mix of fuels changes as generation from new natural gas-fired facilities is added in the 2020 to 2030 time period. In the LTER Reference Case in 2010, 60 percent of generation in Maryland is from coal-fired facilities, 32 percent from nuclear, and 2 percent from natural gas. In 2020, when the first new natural gas plant is built, generation from coal is 58 percent of the total; nuclear, 27 percent; and natural gas, 5 percent. From 2021 through 2030, natural gas generation continues to gain a larger share of generation in Maryland, and in 2030 it accounts for 21 percent of total generation, while coal accounts for 48 percent and nuclear 23 percent. Hydro plus renewable energy generation accounts for 7 percent in 2010, with that generation share increasing slightly to 8 percent by 2030, as Maryland sources the majority of its RPS requirements from lower-cost resource areas of PJM. Table 4.5, below, shows the generation shares of the various resources.

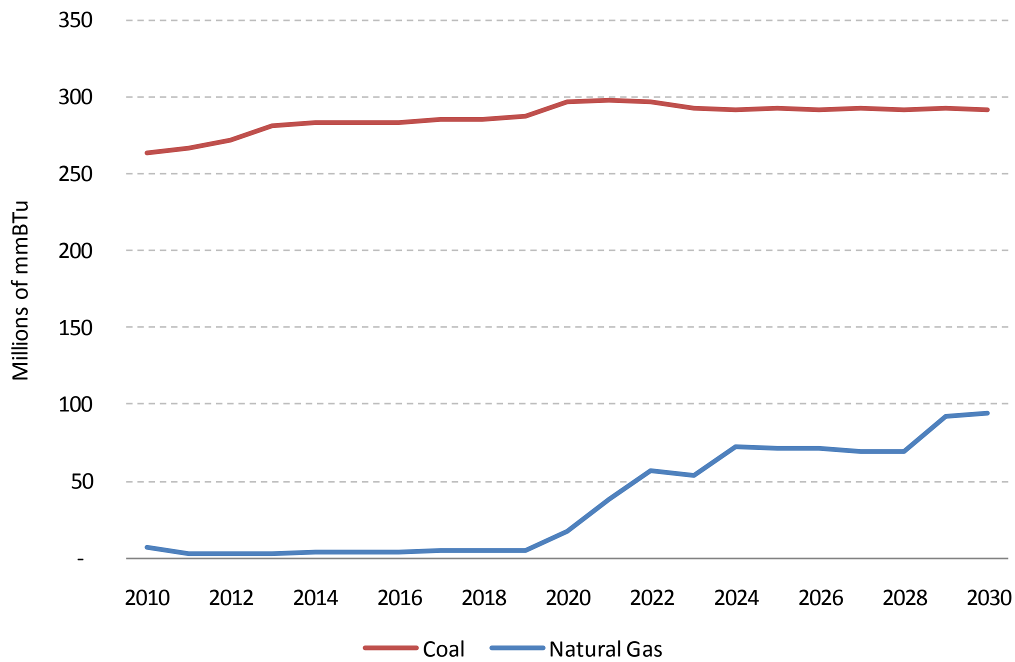
Table 4.5
LTER Reference Case Maryland Generation Shares by Fuel Type (%)

Year	Percent Natural Gas	Percent Coal	Percent Nuclear	Percent Hydro	Percent Renewables
2010	2%	60%	32%	5%	2%
2011	1	61	31	5	2
2012	1	60	30	5	5
2013	1	60	30	5	5
2014	1	60	30	5	5
2015	1	60	29	5	5
2016	1	60	29	5	5
2017	1	60	29	5	5
2018	1	60	29	5	5
2019	1	60	29	5	5
2020	5	58	27	4	5
2021	10	55	26	4	5
2022	14	53	25	4	5
2023	13	53	25	4	5
2024	17	50	24	4	5
2025	17	51	24	4	5
2026	17	50	24	4	5
2027	17	51	24	4	5
2028	17	51	24	4	5
2029	21	48	23	4	4
2030	21	48	23	4	4

*Annual shares may not sum to 100 percent due to independent rounding.

Although coal-fired resources lose generation share as natural gas-fired facilities are built to meet load growth, coal capacity and coal use remain relatively stable over the study period. Figure 4.2, below, outlines coal and natural gas consumption in Maryland in the electricity sector. No new coal generation is added in Maryland; however, during the study period, existing coal capacity begins to operate at higher capacity factors resulting in a slight increase in coal use.

Figure 4.2 Coal and Natural Gas Consumption for Electricity Generation in Maryland



4.5 Energy Prices

Energy prices in all zones increase steadily in real terms until 2020 when new generation begins to come on-line. Real energy prices then stabilize and remain relatively flat through 2030. There is a marked difference between energy prices in the western portions of PJM in relation to the eastern zones, with prices in the eastern zones increasing more rapidly. Energy prices start converging in the last five years of the study period indicating that generation is being built by the model in both the eastern and western zones to address their demand growth, as well as to replace generation when older plants retire. Table 4.6 shows the all-hours energy prices for PJM-

SW, PJM-MidE, PJM-APS, and the PJM average. Energy prices in eah of the three Maryland zones are higher than the PJM average energy prices throughout the study period.[17]

Table 4.6
All-Hours Energy Prices (2010 $/MWh)

Year	PJM-SW	PJM-MidE	PJM-APS	PJM Average
2011	40.28	42.78	38.99	36.51
2012	43.01	46.31	41.83	38.78
2013	45.50	48.97	44.41	40.67
2014	49.42	53.40	48.09	43.84
2015	53.11	57.98	51.51	47.09
2016	57.12	61.19	55.29	50.08
2017	60.64	64.71	58.37	52.83
2018	64.49	67.09	61.51	55.43
2019	66.52	67.85	63.23	57.11
2020	69.46	69.61	65.92	59.13
2021	68.52	69.74	66.40	59.47
2022	68.33	69.98	66.75	59.70
2023	69.16	70.37	67.46	60.31
2024	67.45	68.88	65.57	59.47
2025	68.40	69.79	65.95	60.28
2026	68.95	69.85	66.00	60.87
2027	68.83	69.50	65.44	61.08
2028	69.04	69.89	65.21	61.57
2029	70.05	70.82	65.97	63.23
2030	70.64	71.86	67.52	65.51

Figure 4.3 through Figure 4.5, below, show the wholesale energy prices for all zones. Lower prices throughout the study period are in the western side of PJM: Cincinnati, First Energy, AEP, and ComEd. Prices in the eastern side of PJM are higher and track together, although the Allegheny (PJM-APS) and Pennsylvania Electric (PJM-WPA) zones converge more strongly towards the PJM western zone prices of the last few years. This price convergence is

[17] Energy prices are hours-weighted rather than load-weighted. Load-weighted prices would be slightly higher since prices tend to be higher when loads are higher.

due to new generation being built in the eastern PJM zones, which reduces imports from western PJM and results in the zone prices in PJM-APS and PJM-WPA aligning more closely with western PJM prices.

Figure 4.3 PJM Real On-Peak Energy Prices

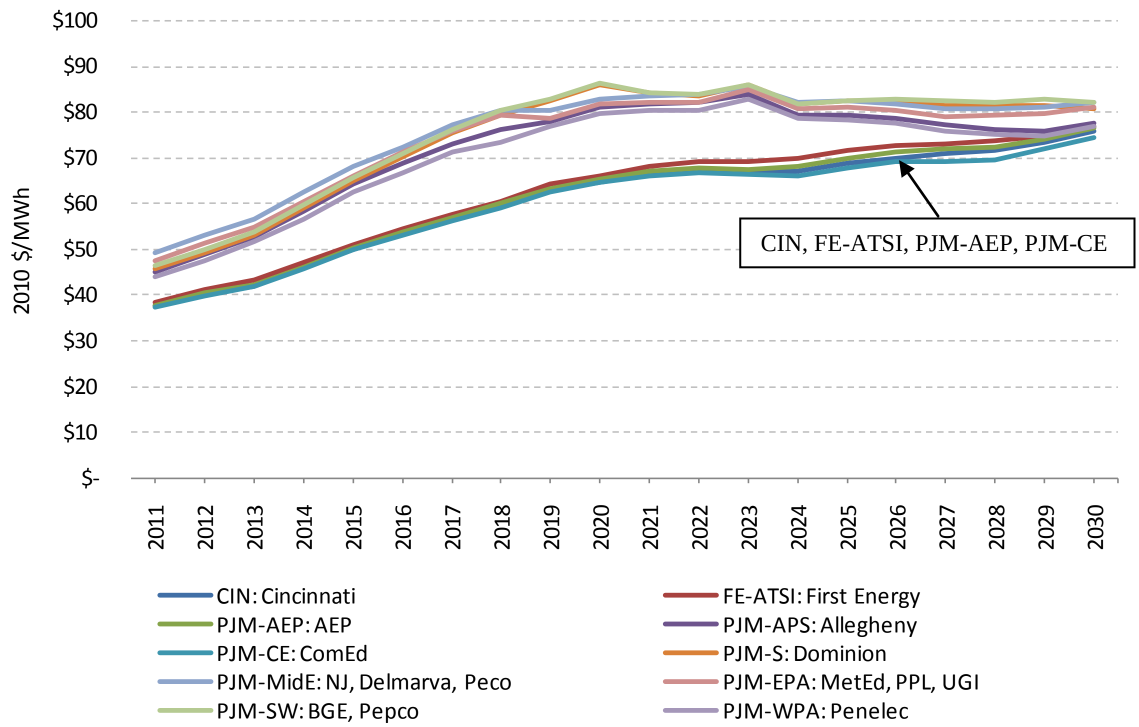


Figure 4.4 PJM Real Off-Peak Energy Prices

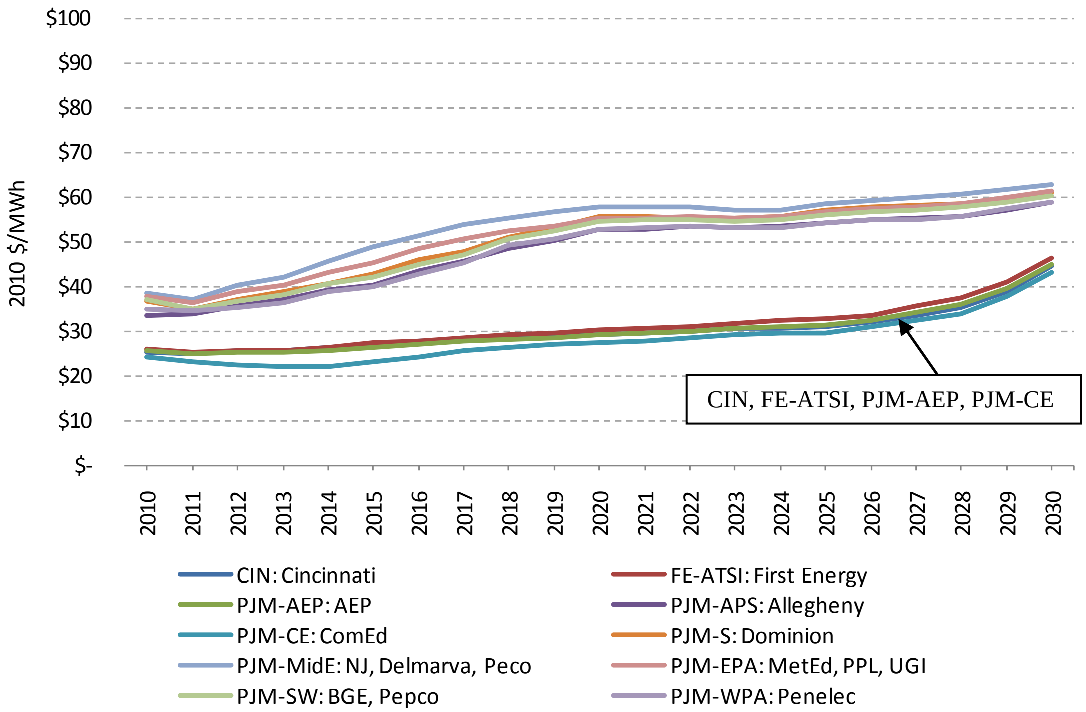
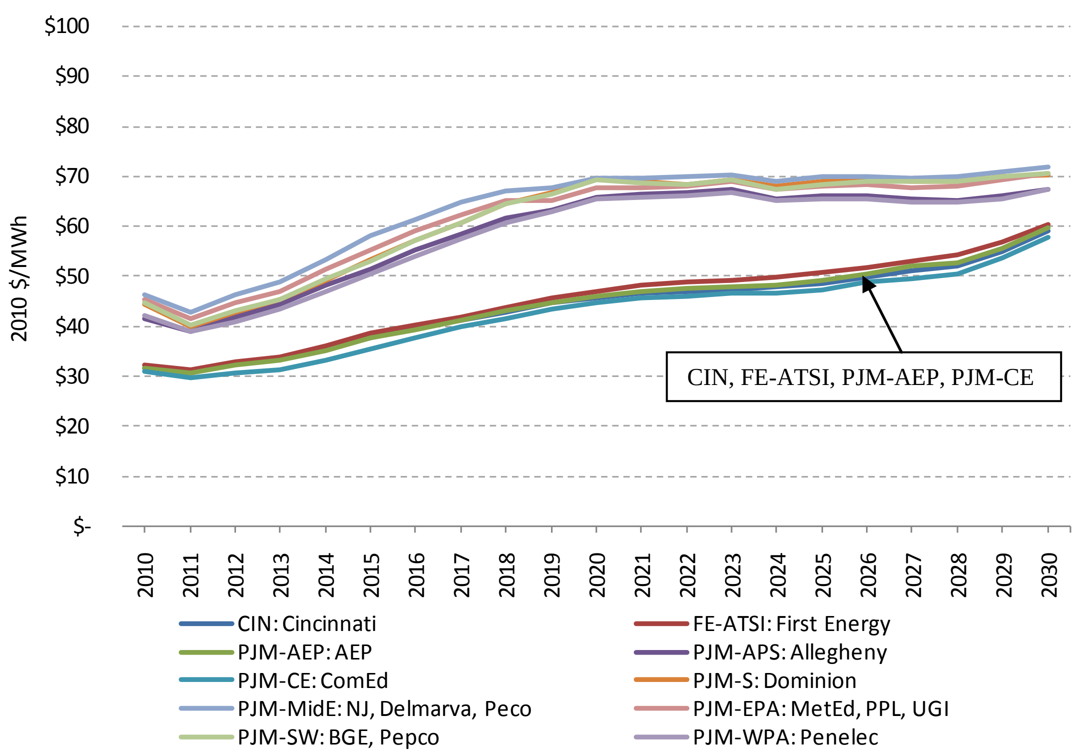


Figure 4.5 PJM Real All-Hours Energy Prices

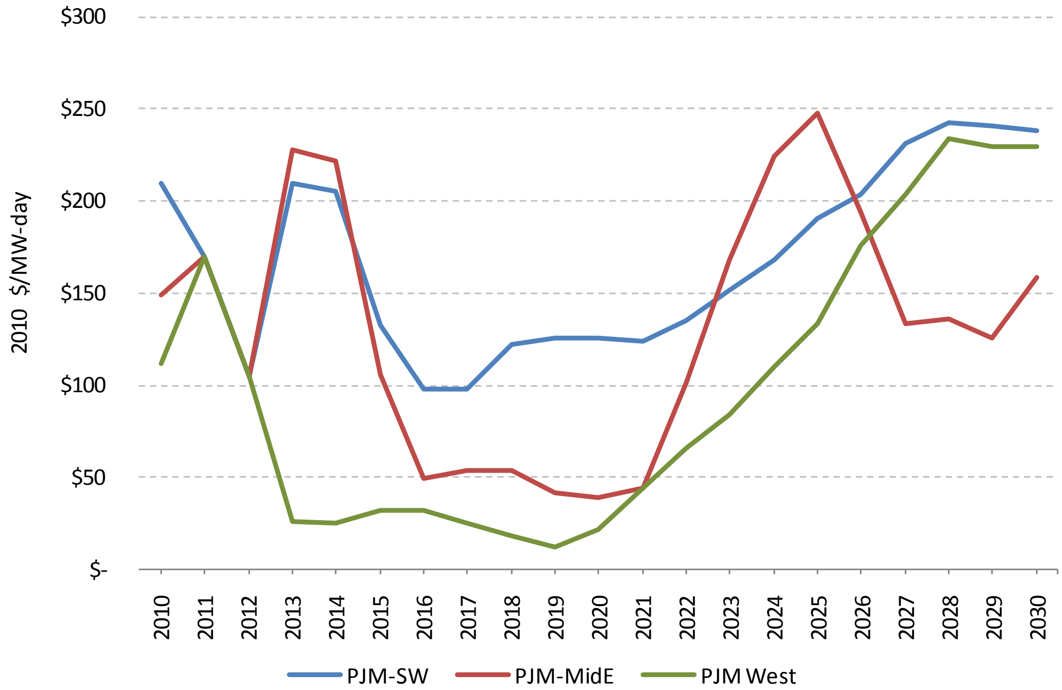


4.6 Capacity Prices

The model uses actual PJM Reliability Pricing Model ("RPM") capacity prices through 2014 (the years available at the time the modeling was conducted). From 2015 to 2019, PJM overall is in a supply surplus situation. [18] Therefore, the capacity values are calculated as "make-whole" payments for the marginal unit (see Chapter 2) until load growth requires new generation additions (post 2019). As new generation is built, capacity prices can be calculated by the model using a cost-of-entry variable and thus capacity costs increase to levels more in line with the cost of new capital during the last ten years of the study period. The average real price (in 2010 dollars) for capacity in the PJM-SW zone from 2021 to 2030 is $193 per MW-day; for PJM-MidE, $150 per MW-day; and for the other PJM zones, $152 per MW-day. In 2029, for PJM-SW and PJM-MidE, capacity prices peak at $249 per MW-day and $266 per MW-day respectively. Figure 4.6 shows the capacity prices for the three Maryland-relevant zones.

[18] By "supply surplus," we mean that available generating capacity exceeds peak demand requirements plus the PJM reserve margin of approximately 15 percent of peak demand.

Figure 4.6 LTER Reference Case Capacity Prices



The capacity prices generated by the Ventyx model can vary significantly from year to year and are highly sensitive to new generation, transmission system expansion, and load levels. Further, when PJM (or a zone within PJM) is characterized by excess generating capacity, capacity prices estimated by the model are generally low ($20 to $50 per MW-day). These results are consistent with actual capacity prices emerging from the PJM RPM auctions for certain zones, such as PJM-APS. Excess reserves, however, also leads to relatively low capacity prices in PJM-SW from 2015 to 2019, which are the years following the availability of actual capacity price data *and* before capacity shortfalls require the addition of new generation facilities. The actual capacity prices for Pepco and BGE for 2013/2014 were in excess of $200 per MW-day, and these prices drop in the first model year (2015) to approximately $142 per MW-day. The most recent RPS auction results, released May 13, 2011, were close to the Ventyx model results demonstrating a significant drop in capacity prices for the 2014/2015 planning year in the Pepco and BGE zones from the 2013/2014 actual RPM auction results, with capacity clearing in each of these zones at $136.50 per MW-day. However, capacity prices for PJM-APS were at $46 per MW-day in the Ventyx model whereas the actual RPM clearing price rose significantly from the previous planning year to $125.99 per MW-day for the 2014/2015 planning year.

It should be recognized that the capacity prices simulated by the model for any particular year may not accurately reflect actual future capacity prices for that year. Capacity price projections are more useful when averaged over several years and used to compare one scenario (e.g., the LTER Reference Case) to alternative scenarios (e.g., the aggressive energy efficiency scenarios).

4.7 Emissions

The Maryland Healthy Air Act ("HAA") applies to Maryland's coal-fired power plants, which have installed the necessary control technologies to remain in compliance. Since no new coal plants are built in Maryland in the LTER Reference Case, emissions from existing plants remain below HAA limits throughout the study period. Emissions rise slightly through 2020 as the Maryland coal plants operate at increasing capacity factors, then stabilize at the maximum output levels through 2030. Figure 4.7, Figure 4.8, and Figure 4.9, below, outline the HAA plant emission for SO_2, NO_x, and mercury.

Figure 4.7 Maryland SO_2 Emissions from HAA Plants

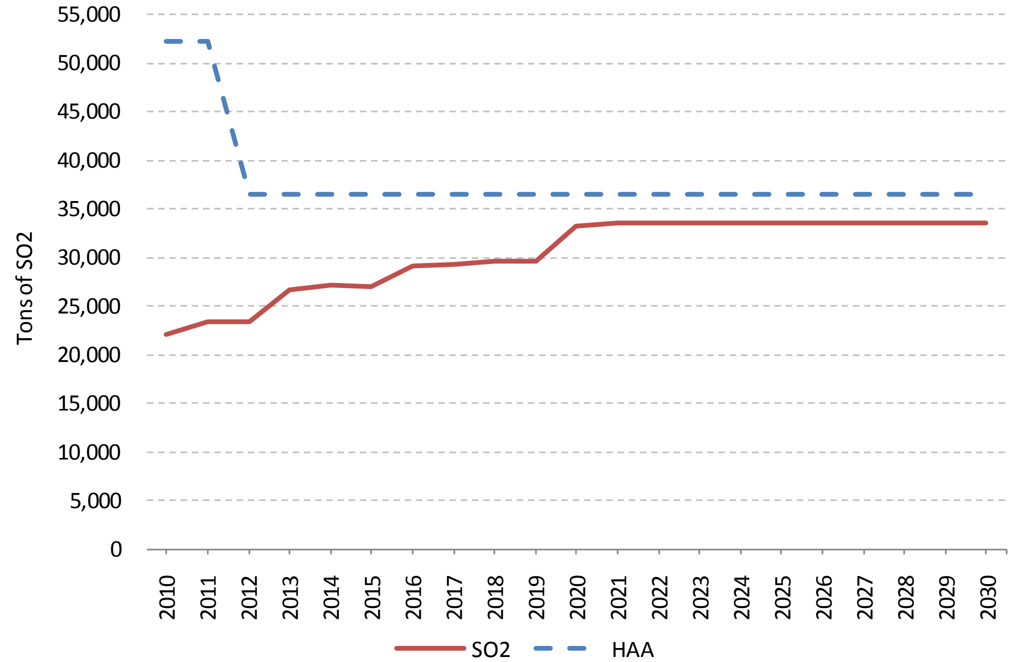


Figure 4.8 Maryland NO_x Emissions from HAA Plants

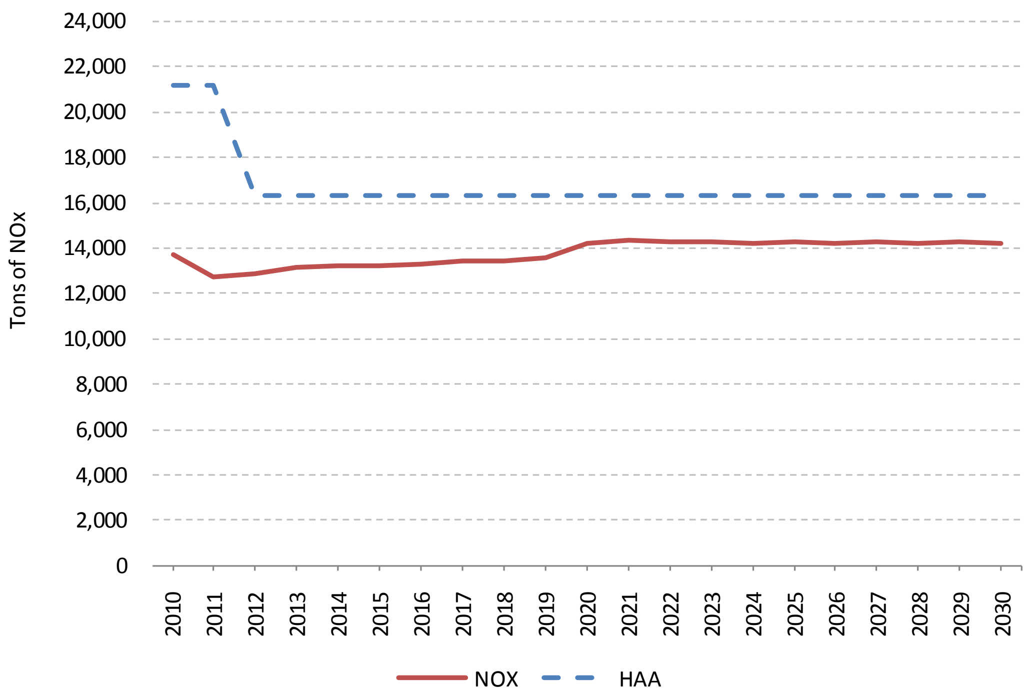
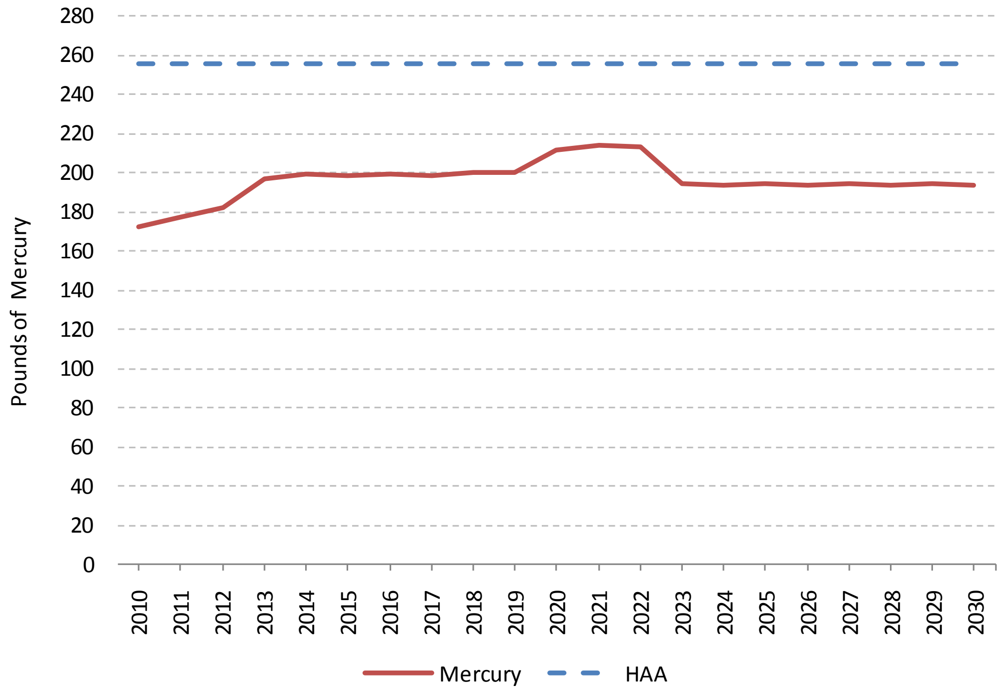


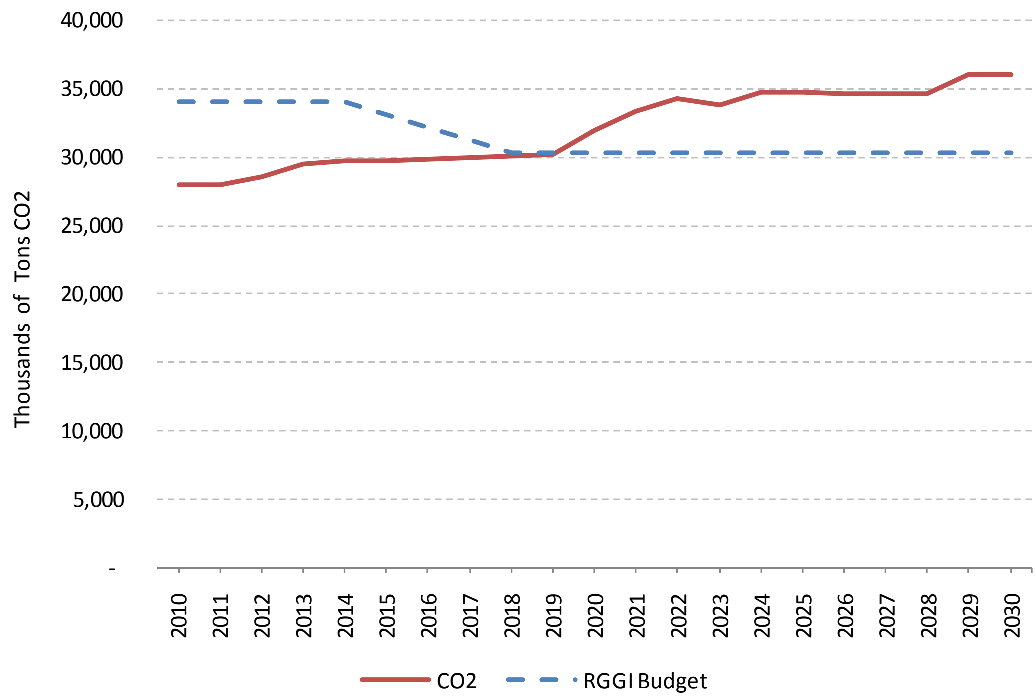
Figure 4.9 Maryland Mercury Emissions from HAA Plants



On a State-wide basis, NO_x emissions rise in the out-years due to the addition of new natural gas-fired facilities. The increase is relatively small as the new plants are assumed to incorporate state-of-the-art emissions control equipment. Total State NO_x emissions from all electric power sources reaches 17,000 tons in 2030.

NO_x and CO_2 emissions rise on a State-wide basis as Maryland coal plants ramp up generation and new natural gas plants are added. Figure 4.10, below, shows State-wide Maryland CO_2 emissions from electric generation facilities , which reach 36 million tons in 2030.

Figure 4.10 Maryland Electric Generation CO_2 Emissions



Note that with the introduction of new natural gas-fired generation in Maryland, and increasing capacity factors for Maryland's existing coal-fired facilities, CO_2 emissions exceed Maryland's Regional Greenhouse Gas Initiative ("RGGI") after 2019. As discussed in Chapter 3, exceeding Maryland's RGGI CO_2 budget during the last ten years of the study period as shown in Figure 4.10 is not viewed as indicating Maryland's inability to adhere to its RGGI obligations.

4.8 Results

The principal results to emerge from the LTER Reference Case analysis, which will be used to gauge the impacts of alternatives to the LTER Reference Case, are:

- Under the LTER Reference Case load assumptions, new generation is not needed to be constructed until 2020. Until that time, there are adequate generation resources in PJM to meet load requirements plus reserve margins.
- New generation resources are expected to be either natural gas combined cycle units or combustion turbines based on least-cost.
- Emissions of NOx, SO_2, and mercury from Maryland power plants subject to Maryland's Healthy Air Act remain below the HAA caps for those pollutants throughout the study period.
- Emissions of CO_2 are shown to exceed Maryland's RGGI budget during the later years of the study period, which will require Maryland generation facilities to purchase RGGI emission allowances from other RGGI states and/or purchase offsets in order for the State to comply with its RGGI obligations.
- Real energy prices are expected to rise during the first half of the study period, then level off, even with increases in the real price (2010 dollars) of natural gas from $4.46 per mmBtu in 2010 to $8.01 per mmBtu in 2030.
- Capacity prices are projected to increase over the study period, and begin to converge at prices approximating the cost of new entry towards the end of the study period. Capacity price differentials among transmission zones are anticipated to diminish as new capacity is added to meet load requirements.

5. INFRASTRUCTURE ALTERNATIVE SCENARIOS

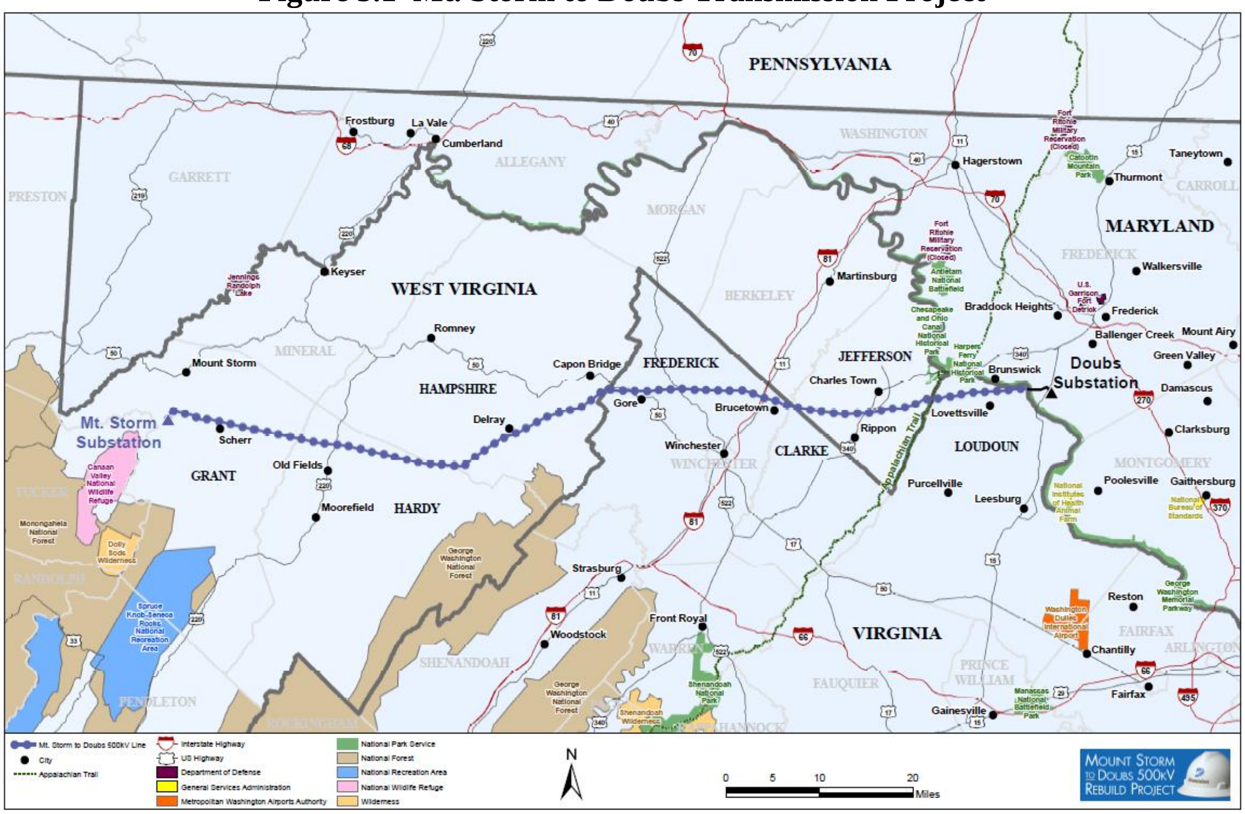
5.1 Introduction

The first set of alternative scenarios consists of select variations on the LTER Reference Case examining specific infrastructure and legislative changes and combinations thereof. The scenarios consider the effects of the following: the construction and operation of Calvert Cliffs Unit 3 ("CC3"); implementation of national carbon legislation, which also includes a national Renewable Portfolio Standard ("NCO2"); construction of the Mt. Storm to Doubs transmission line upgrade ("MSD"); and construction of the Mid-Atlantic Power Pathway transmission project ("MAPP").

Calvert Cliffs Unit 3 is added to the model in 2019 at an assumed capacity of 1,600 MW. National carbon legislation is assumed to take effect in 2015 and is implemented as a cost on carbon emissions of $16 per ton (2010 $) in 2015, increasing by $1 per ton annually through 2023 and then by an average of about $4.50 per ton each year through 2030 to reach a maximum allowance price of $54 per ton (2010 $) of CO_2 in 2030. This assumption, developed by Ventyx, is consistent with proposed cap-and-trade legislation previously introduced in Congress (e.g., by the Waxman-Markey Bill of 2009). A federal Renewable Portfolio Standard ("RPS") is included as part of the carbon legislation and is set at 12 percent by 2020. States with more aggressive state-level RPS requirements still meet the higher state standard. The 12 percent standard is based on the Waxman-Markey Bill (the American Clean Energy and Security Act), although adjusted downward to capture a higher likelihood of adoption.

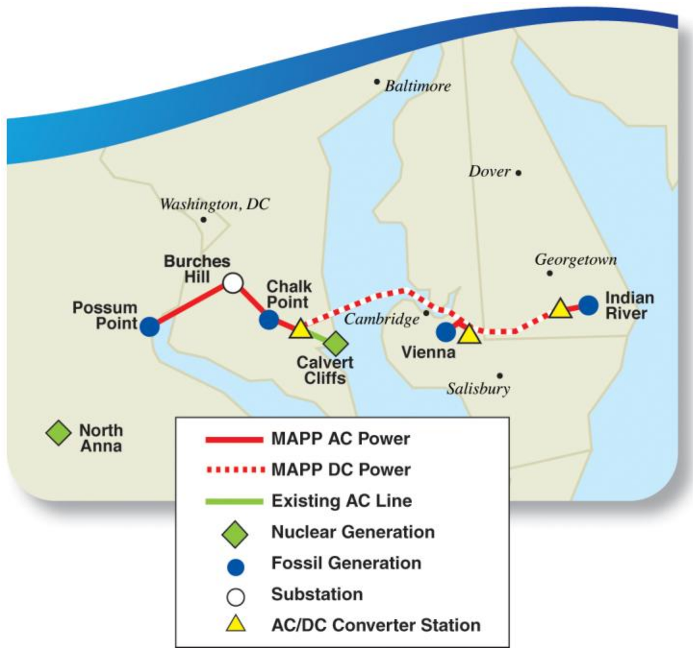
The Mt. Storm to Doubs transmission project, shown in Figure 5.1 below, comes on-line in 2015, increasing bi-directional transfer capability between PJM-APS and PJM-SW by 1,700 MW. The MAPP project is put in-service in 2018 (see Figure 5.2), increasing transmission capacity between PJM-SW and PJM-MidE by 2,500 MW and between PJM-SW and PJM-S by 1,250 MW. The MAPP project was originally planned to be in-service in 2015, however, at the time of this analysis PJM was reviewing the projected date the MAPP line would be needed. The LTER opted to delay the inclusion of the MAPP project to 2018 in keeping with the uncertainty surrounding the project. The later in-service date is deemed to be a more plausible outcome. The six stand-alone/combination alternative scenarios examined are: MSD alone, MAPP alone, MSD+MAPP, CC3 alone, CC3+NCO2, and CC3/NCO2/MSD/MAPP.

Figure 5.1 Mt. Storm to Doubs Transmission Project



Source: Mount Storm to Doubs Rebuild Project website: http://www.dom.com/about/electric-transmission/mtstorm/index.jsp

Figure 5.2 MAPP Transmission Project

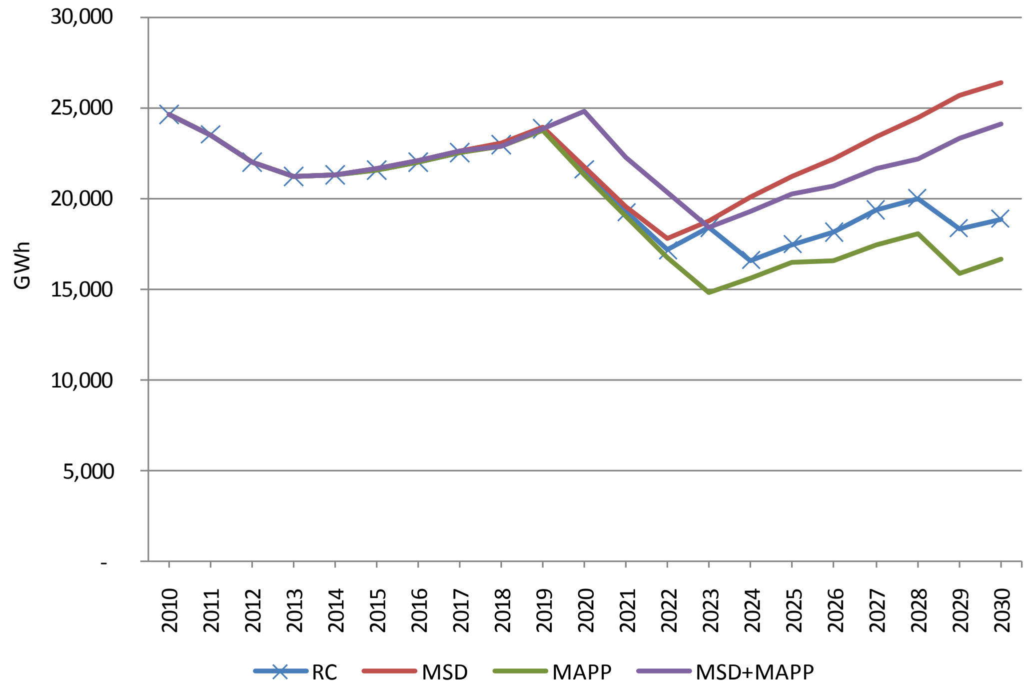


Source: MAPP Project website: http://webapps.powerpathway.com/mapp/

5.2 Net Imports

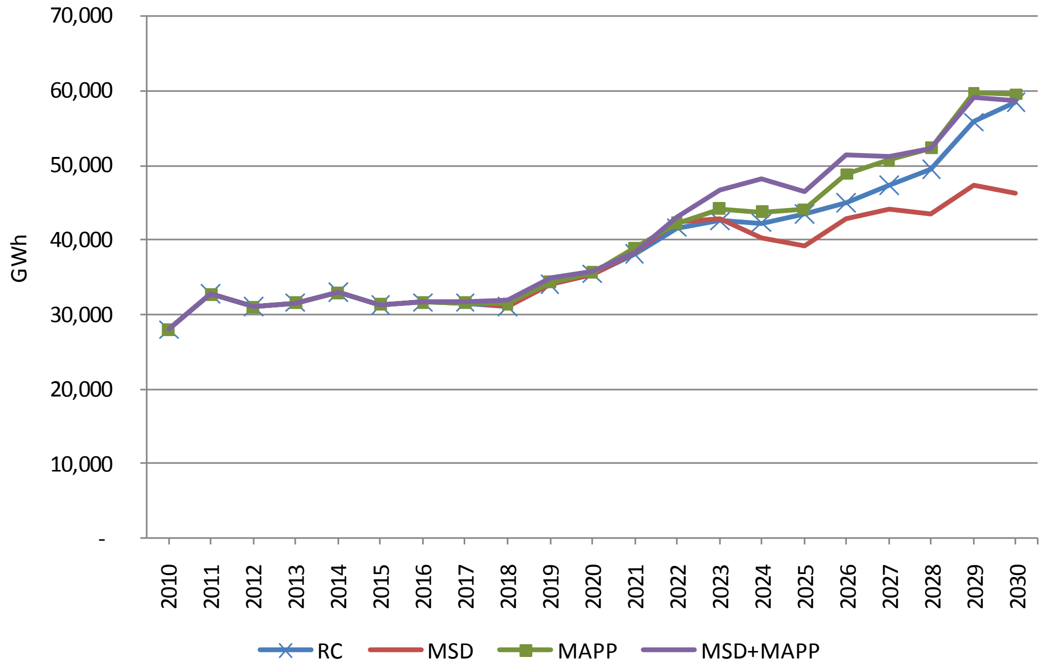
Net imports are strongly affected by both transmission improvements and carbon legislation, and, in PJM-SW, by the capacity addition represented by CC3. PJM-SW and PJM-MidE are significant importers of energy from PJM-APS and other Western PJM zones. Figure 5.3, below, shows the effect of transmission upgrades on PJM-SW net imports.

Figure 5.3 PJM-SW Net Imports Under Transmission Scenarios



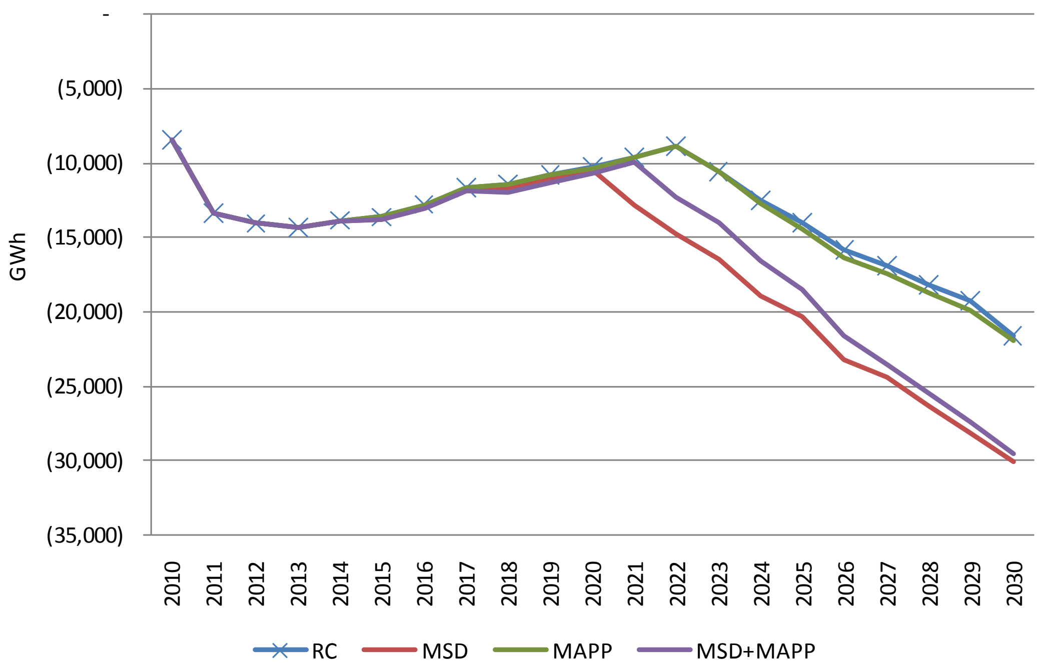
As with the LTER Reference Case, once new capacity begins to be built in the zone, net imports start to decline. Net imports in both scenarios with MSD are higher than under the LTER Reference Case as the transmission project increases transfer capability from PJM-APS to PJM-SW, facilitating a larger amount of net imports into the PJM-SW zone from Western PJM. Under MSD+MAPP, net imports are slightly lower than for MSD alone, as PJM-SW also exports some energy to PJM-MidE due to the increased transfer capability between the two zones from the MAPP project. Net imports with the MAPP project alone are lower than the LTER Reference Case due to an increase in exports into PJM-MidE. PJM-MidE imports as much electricity as possible because capacity in that zone is relatively expensive. Figure 5.4 shows net imports into PJM-MidE and mirrors the effects discussed above.

Figure 5.4 PJM-MidE Net Imports Under Transmission Scenarios



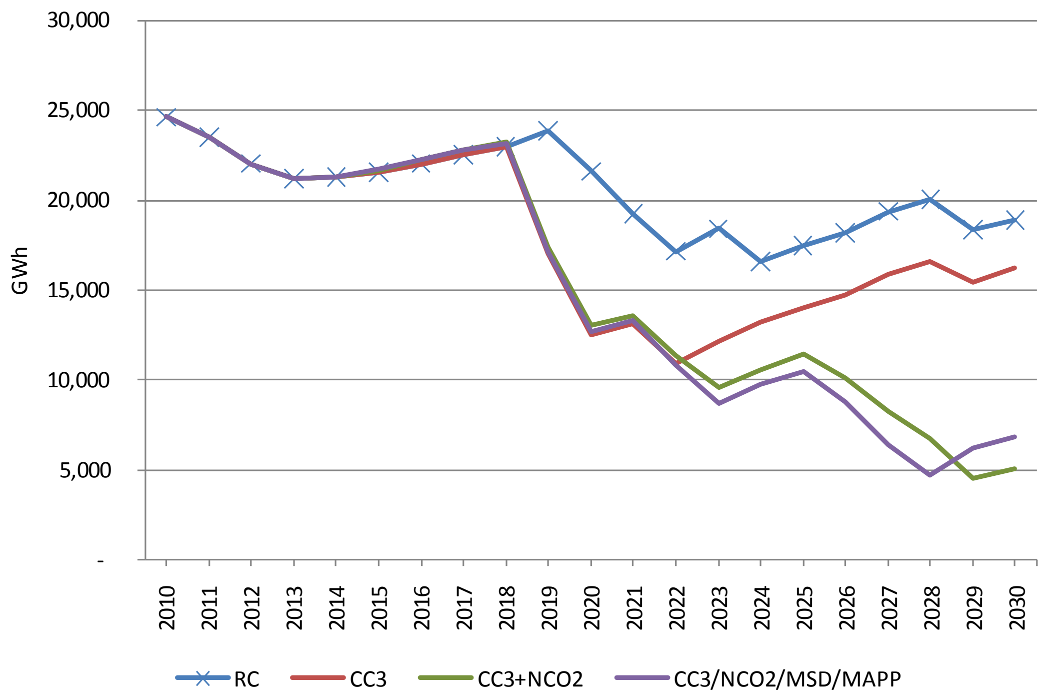
Under the MSD scenario, increased imports into PJM-SW from Western PJM means reduced capacity additions in PJM-SW, and, therefore, reduced import opportunities into PJM-MidE. This effect is mitigated by the addition of MAPP, which allows the additional electricity from the western zones to continue into PJM-MidE, the eastern-most PJM zone. PJM-APS remains an exporter throughout the study period because it is a lower-cost zone compared to PJM-SW and PJM-MidE. Exports steadily increase into the Eastern zones in the last ten years of the study period, as load growth catches up with regional supply and new capacity additions begin to come on-line. Exports from PJM-APS are highest under the MSD scenarios due to the increased transfer capability into the PJM-SW (see Figure 5.5).

Figure 5.5 PJM-APS Net Imports Under Transmission Scenarios



Net imports for PJM-SW in the CC3 scenarios drop significantly due to the addition of the new capacity in the zone. Figure 5.6, below, shows PJM-SW net imports under the CC3 scenarios.

Figure 5.6 PJM-SW Net Imports Under CC3 Scenarios



Under CC3 alone, PJM-SW net imports decline when Calvert Cliffs 3 comes on-line and increase beginning in the early 2020's once load growth has fully absorbed the CC3 addition and new resources are needed. With the addition of national carbon legislation, imports remain low as coal-fired generation becomes displaced in all zones (discussed in detail in the next section on capacity additions). Net imports in PJM-MidE and PJM-APS are very similar to the LTER Reference Case results, as PJM-MidE will still utilize the lowest cost resources (imports) first and PJM-APS will continue to build the lower-cost resources and export power to the east (see Figure 5.7 and Figure 5.8 below).

Figure 5.7 PJM-MidE Net Imports Under CC3 Scenarios

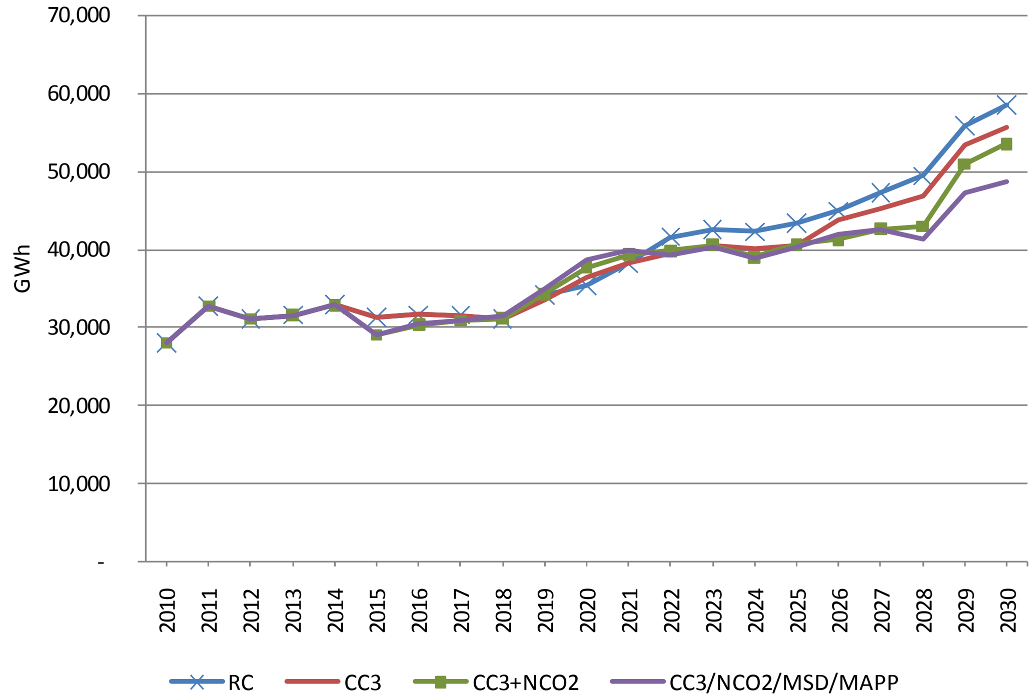
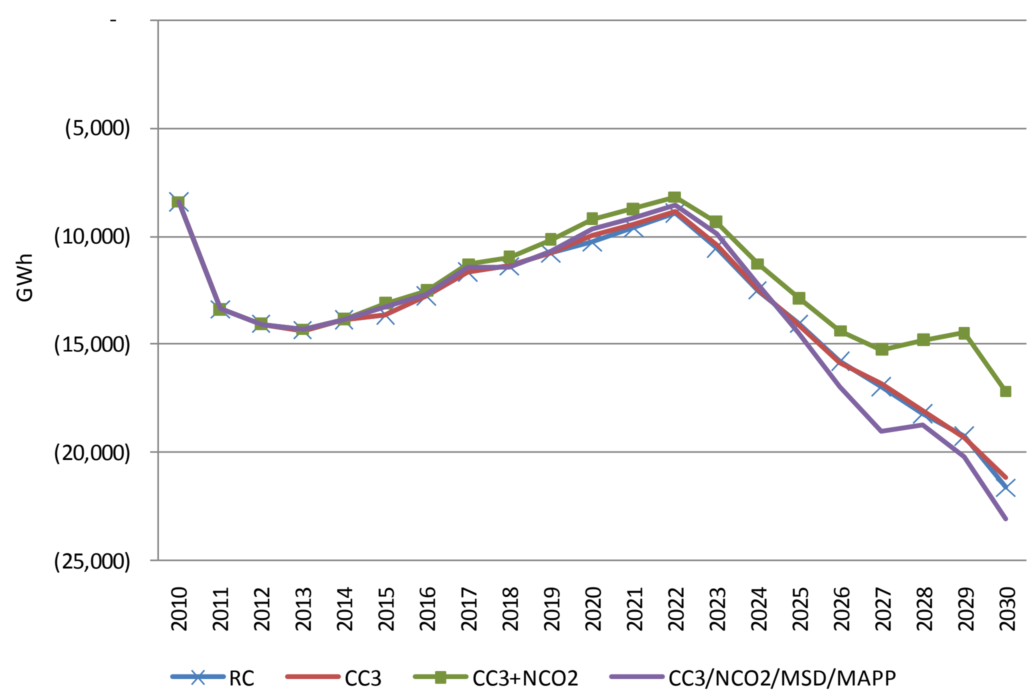


Figure 5.8 PJM-APS Net Imports Under CC3 Cases



5.3 Capacity Additions and Retirements

Planned capacity additions and age-based retirements are the same as those assumed for the LTER Reference Case. Table 5.1, below, shows the cumulative retirements and capacity reductions resulting from retrofits in PJM under the infrastructure and national carbon legislation scenarios.

Table 5.1
Cumulative Retirements and Retrofit Capacity Reductions in PJM (MW)

Retirements				Retrofits
Year	CC3, MSD, MAPP, and MSD+MAPP	CC3+NCO2	CC3/NCO2/MSD/MAPP	CC3+NCO2 and CC3/NCO2/MSD/MAPP
2015	0			
2016	194	206	206	
2017	221	327	327	
2018	221	718	718	
2019	221	855	1,099	
2020	315	855	1,099	
2021	315	855	1,099	
2022	315	855	1,099	
2023	315	855	1,099	
2024	315	855	1,099	
2025	315	855	1,099	
2026	315	855	1,099	1,499
2027	315	855	1,099	1,931
2028	315	855	1,099	3,778
2029	315	855	1,099	5,285
2030	315	855	1,099	6,745

Economic retirements are unaffected by the transmission changes or the construction of an additional unit at Calvert Cliffs, remaining at 315 MW for the MSD, MAPP, MSD+MAPP, and CC3 scenarios. Economic retirements are, however, affected by the implementation of carbon legislation. More importantly, many coal-fired plants are retrofitted with carbon sequestration technology in the last six years of the study period when carbon prices accelerate. Plants retrofitted with carbon sequestration technology are assumed to experience a 33 percent reduction in usable capacity and a 33 percent increase in heat rate due to the introduction of these controls.[19] These plants are also assumed to have an increase in O&M costs, which changes their position in the model's dispatch stack.[20] Under CC3+NCO2, economic retirements rise modestly to 855 MW. However, a total of 6,745 MW of generation capacity is lost due to retrofit de-rates. In the CC3/NCO2/MSD/MAPP scenario, de-rates also equal 6,745 MW. Although the transmission changes alone do not affect retirements, transmission upgrades combined with national carbon legislation and CC3 cause one additional 251 MW plant retirement in western PJM.

Total generic natural gas capacity additions for PJM as a whole are largely unaffected by the transmission additions. Table 5.2, below, shows the cumulative natural gas capacity built by the model through 2030 for the Maryland-relevant zones.

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[19] Heat rate is a measure of power plant efficiency generally expressed as mmBtu per kWh, a higher heat rate is an efficiency loss, i.e., it takes more heat input to produce a kWh of energy. Retrofit assumptions developed by Ventyx based on engineering analysis conducted by Ventyx.

[20] With the exception of intermittent renewable generation, (i.e., wind and solar), the Ventyx model dispatches generation in economic merit order, that is, the least costly generation resource is dispatched first to meet load requirements.

Table 5.2
Cumulative Natural Gas Capacity Additions Through 2030 (MW)

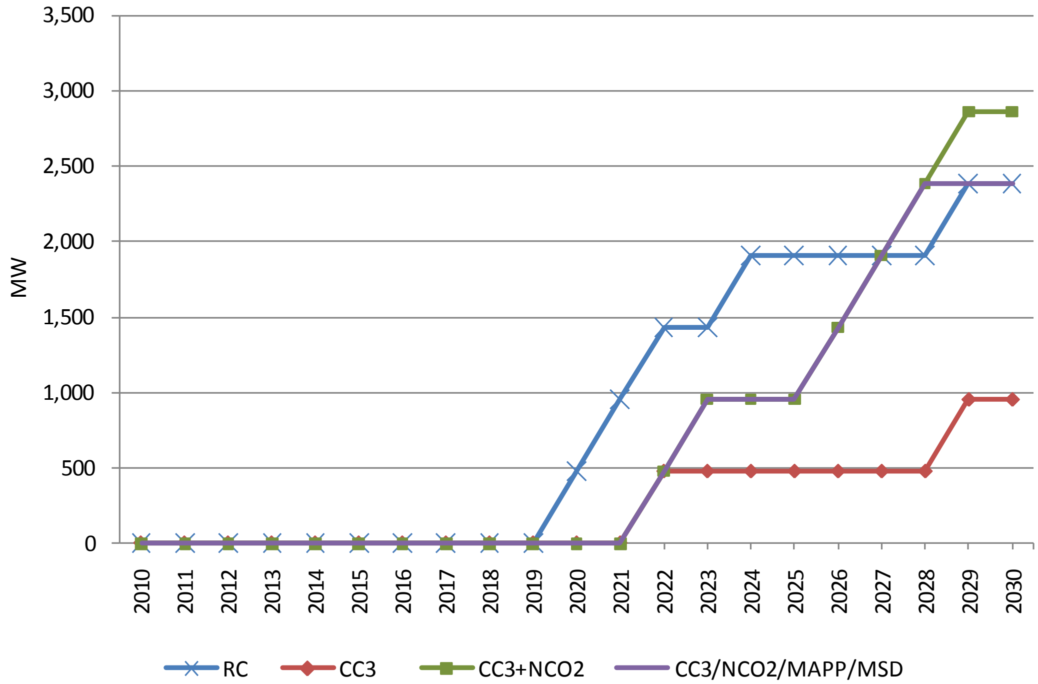
Scenario	PJM-SW	PJM-MidE	PJM-APS	PJM Total
RC	2,385	1,908	3,816	30,101
MSD	1,431	3,816	4,770	30,145
MAPP	2,385	1,908	3,816	30,101
MSD+MAPP	1,431	2,082	4,293	30,016
CC3	954	2,385	3,816	28,496
CC3+NCO2	2,862	2,385	3,816	35,273
CC3/NCO2/MSD/MAPP	2,385	4,467	3,816	35,661

The project builds under the MAPP scenario are identical to the LTER Reference Case. Generic capacity additions at a zonal level are strongly influenced by the Mt. Storm to Doubs transmission line. The MSD project increases the transfer capability between PJM-APS and PJM-SW. This increased capability allows PJM-SW to increase imports from western PJM, which is a lower-cost solution than building capacity. However, MSD does not increase transmission capacity between PJM-SW and PJM-MidE. Therefore, increased imports are not available to the PJM-MidE zone, from either western PJM or from new plants in PJM-SW as PJM-SW builds less capacity, having satisfied load growth requirements through imports. As a result, under the MSD assumptions, PJM-MidE total natural gas capacity additions double to 3,816 MW, because PJM-MidE must meet a larger portion of its load growth requirements through self-builds. PJM-APS also builds additional capacity in the MSD scenario, as it is an exporting zone and can sell more energy into PJM-SW. This effect is mitigated by the addition of the MAPP project, which increases transmission capacity from PJM-SW to PJM-MidE. Under MSD+MAPP, PJM-MidE can access the lower-cost energy from PJM-APS, and, therefore, needs to build only one additional peaking plant compared to the least-cost build schedule simulated for the LTER Reference Case.

The addition of CC3 and carbon legislation significantly affects both the magnitude and timing of natural gas capacity additions. As discussed earlier, under carbon legislation, existing generating capacity is reduced mainly due to retrofit de-rates. As a result, more new natural gas generation is required to make up for the lost capacity, resulting in over 5,000 MW of new natural gas capacity in PJM as a whole under the carbon legislation scenarios compared to the LTER Reference Case (see Table 5.2 on the previous page).

The addition of CC3 affects capacity additions mainly in PJM-SW and PJM-MidE. PJM-APS builds the same amount of new natural gas capacity under all three CC3 scenarios as in the LTER Reference Case. Under CC3 alone, the extra capacity is utilized by PJM-MidE as it is not needed in PJM-SW. In the scenarios with national carbon legislation, PJM-APS is also building replacement capacity due to retirements and retrofit de-rates. Figure 5.9, below, shows the natural gas capacity additions in PJM-SW under the various CC3 scenarios.

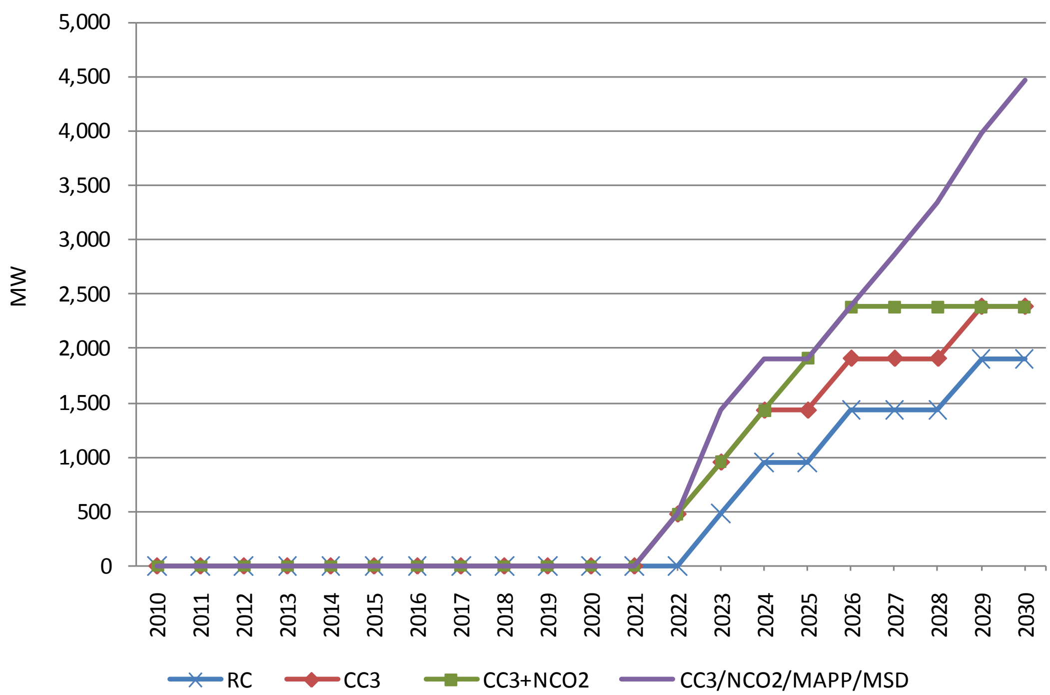
Figure 5.9 PJM-SW Natural Gas Capacity Additions



CC3 alone displaces much of the need for new natural gas generation in PJM-SW and delays those builds for two years. When carbon legislation is added, additional new natural gas generation is required to make up for the reduction in existing capacity due to retirements and retrofit de-rates, and the amount of total new generation built is higher than in the LTER Reference Case. Transmission improvements increase transfer capacity both into and out of PJM-SW and therefore the same amount of new natural gas capacity is built in the zone as in the LTER Reference Case to satisfy both load growth and retirement and retrofit losses. The MSD effect mitigates the need for new builds by one less combined cycle plant compared to the CC3+NCO2 scenario.

Figure 5.10, below, shows the natural gas capacity additions in PJM-MidE for the CC3 scenarios. Under all CC3 scenarios, PJM-MidE is required to build more capacity than in the LTER Reference Case and capacity builds begin a year earlier.

Figure 5.10 PJM-MidE Natural Gas Capacity Additions



Under CC3 alone, PJM-SW builds only a few new natural gas plants to satisfy load growth in later years, and therefore no additional imports are available for transfer into PJM-MidE. With the addition of carbon legislation, PJM-MidE builds the same amount as in CC3 alone but slightly earlier. Only a single minor retrofit capacity reduction occurs in PJM-MidE, and, therefore, the zone is only minimally affected by retirement and retrofit decisions. As discussed earlier, the MSD effect is significant in PJM-MidE and the zone needs to satisfy a larger portion of its load growth requirements through new natural gas generation capacity additions under the CC3/NCO2/MSD/MAPP scenario.

5.4 Fuel Use

Fuel use in Maryland mirrors the net import and capacity build patterns. Table 5.3, below, shows the coal and natural gas usage for electricity generation in Maryland under the transmission and CC3 alone scenarios.

Table 5.3
Fuel Usage in Maryland in 2030 (mmBTU)

Scenario	Coal	Natural Gas
RC	292,159,864	93,701,484
MSD	291,989,236	43,068,200
MAPP	292,255,074	108,892,353
MSD+MAPP	292,228,690	58,010,633
CC3	291,997,430	25,996,962
CC3+NCO2	283,917,440	120,402,872
CC3/NCO2/MSD/MAPP	283,935,860	107,721,991

With MSD, Maryland imports more energy and builds fewer natural gas plants. Therefore, coal usage is slightly lower and natural gas usage is less than half that of the LTER Reference Case. With MAPP alone, Maryland coal usage changes very little and natural gas usage is slightly higher than in the LTER Reference Case due to the slight increase in exports to PJM-MidE that are facilitated by the transmission project. The MSD+MAPP scenario shows the combined effect of the increased imports from PJM-APS and increased exports into PJM-MidE. The addition of CC3 has the largest impact on fuel usage in Maryland, as the project eliminates the need for several incremental natural gas plants. The addition of a carbon price reduces coal usage by approximately 8.2 million mmBtu, with the lost generation made up by additional natural gas plants; hence, the large increase in natural gas usage.

5.5 Energy Prices

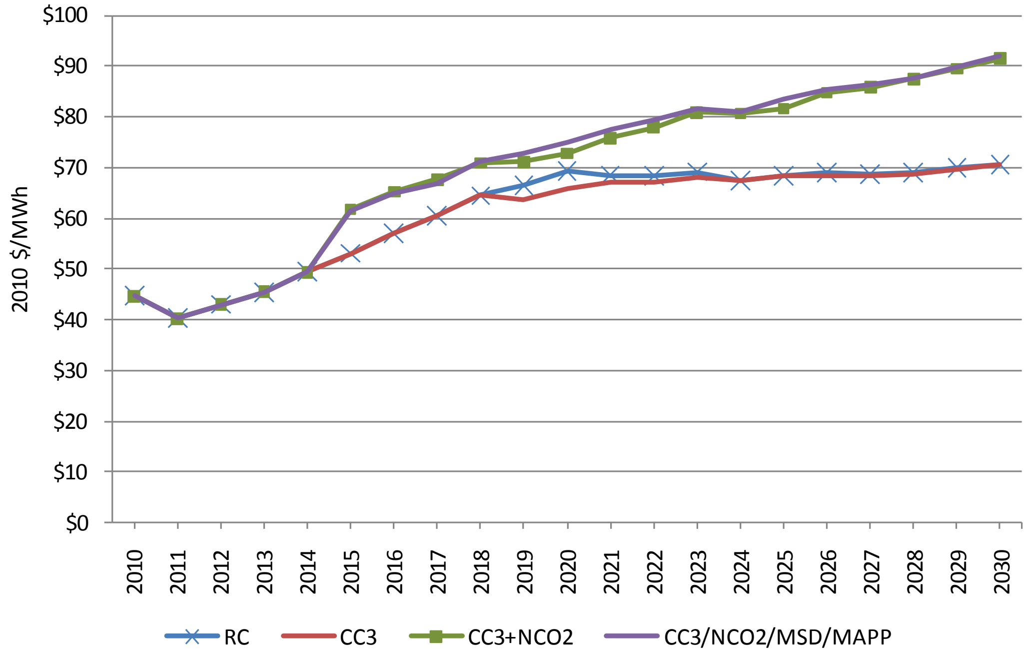
Wholesale energy prices in the three Maryland-relevant zones are only marginally affected by transmission improvements. PJM-SW energy prices are almost identical to the LTER Reference Case throughout the study period under the transmission scenarios (see Table 5.4 below). PJM-MidE and PJM-APS prices at the end of the study period are slightly higher in the scenarios with MSD due to its effect on import/export flows.

Table 5.4
Real All-Hours Energy Prices in the Transmission Scenarios
(2010 $/MWh)

	RC	MSD	MAPP	MSD+MAPP
PJM-SW	70.64	69.66	71.11	70.94
PJM-MidE	71.86	72.11	71.91	72.04
PJM-APS	67.52	68.13	67.58	68.47

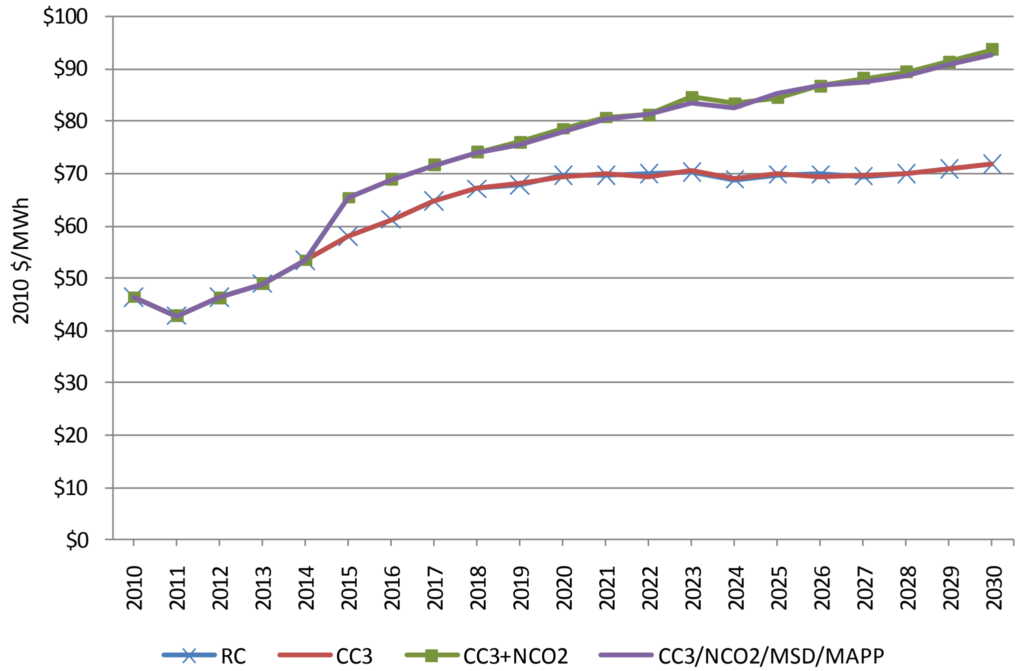
National carbon legislation has a significant impact on wholesale energy prices. Figure 5.11, below, shows the energy prices for PJM-SW under the CC3 scenarios. With CC3 alone, PJM-SW energy prices experience a transitory mid-term price decrease when the unit first comes on-line but then converge to the long run LTER Reference Case price. Energy prices, however, continue to escalate along a carbon price path throughout the study period for the NCO2 scenarios.

Figure 5.11 PJM-SW Real All-Hours Energy Prices



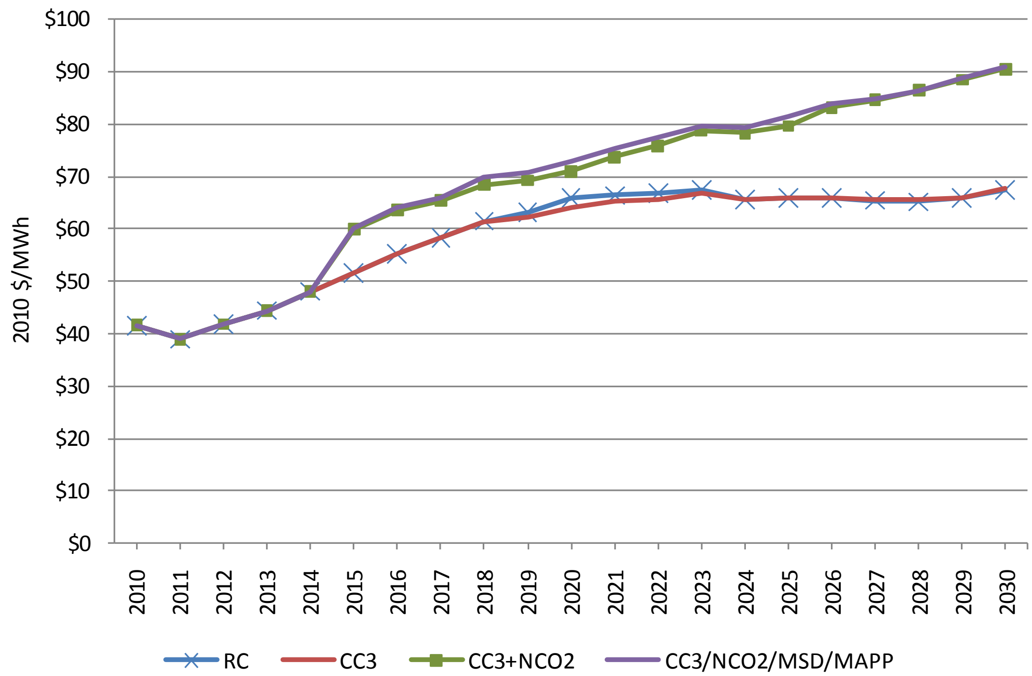
PJM-MidE prices are unaffected by CC3 and follow the same carbon price trajectory under the NCO2 cases (see Figure 5.12).

Figure 5.12 PJM-MidE Real All-Hours Energy Prices Under CC3 Scenarios



PJM-APS prices display the mid-term CC3 price dip due to the short-term small reduction in exports into PJM-SW from the capacity addition in that zone (see Figure 5.13 below).

Figure 5.13 PJM-APS Real All-Hours Energy Prices Under CC3 Scenarios



5.6 Capacity Prices

Relative to the LTER Reference Case, the transmission upgrade, CC3, and national carbon legislation scenarios exhibit distinct and sustained adjusted trends in PJM-SW and PJM-MidE. Capacity prices in PJM-SW are lower in all of these cases compared to the LTER Reference Case, and, in PJM-MidE, the capacity prices tend to be higher than in the LTER Reference Case. The four figures below display the capacity prices for PJM-SW and PJM-MidE under the six different scenarios. The PJM-MidE capacity prices display the same volatility as found in the LTER Reference Case due to the timing of the capacity builds.

Figure 5.14 PJM-SW Capacity Prices for Transmission Scenarios

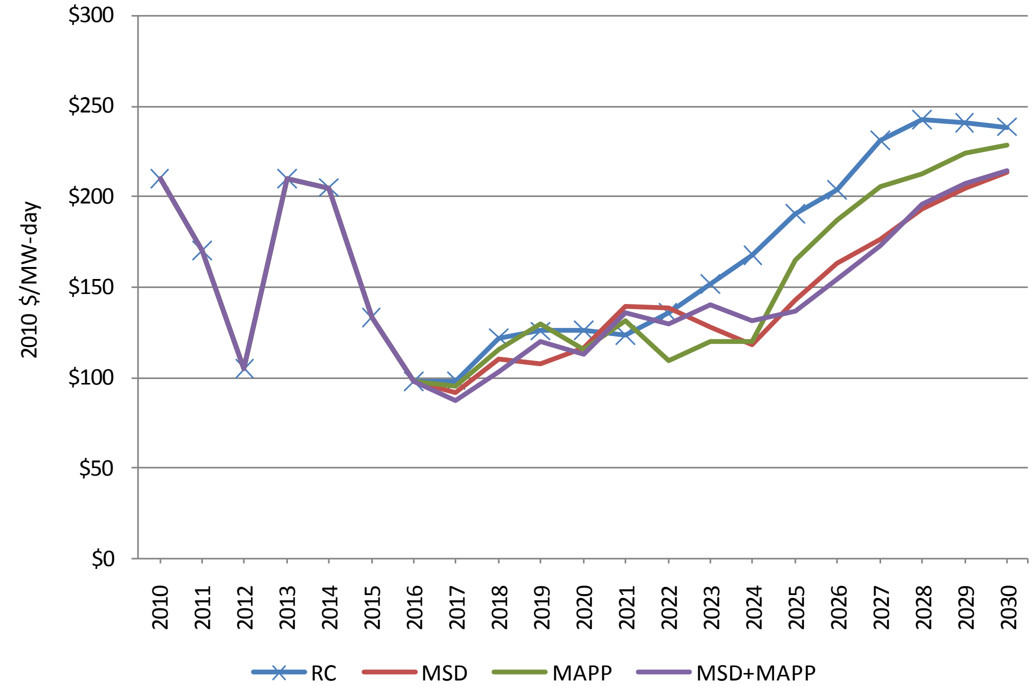


Figure 5.15 PJM-SW Capacity Prices for CC3 Scenarios

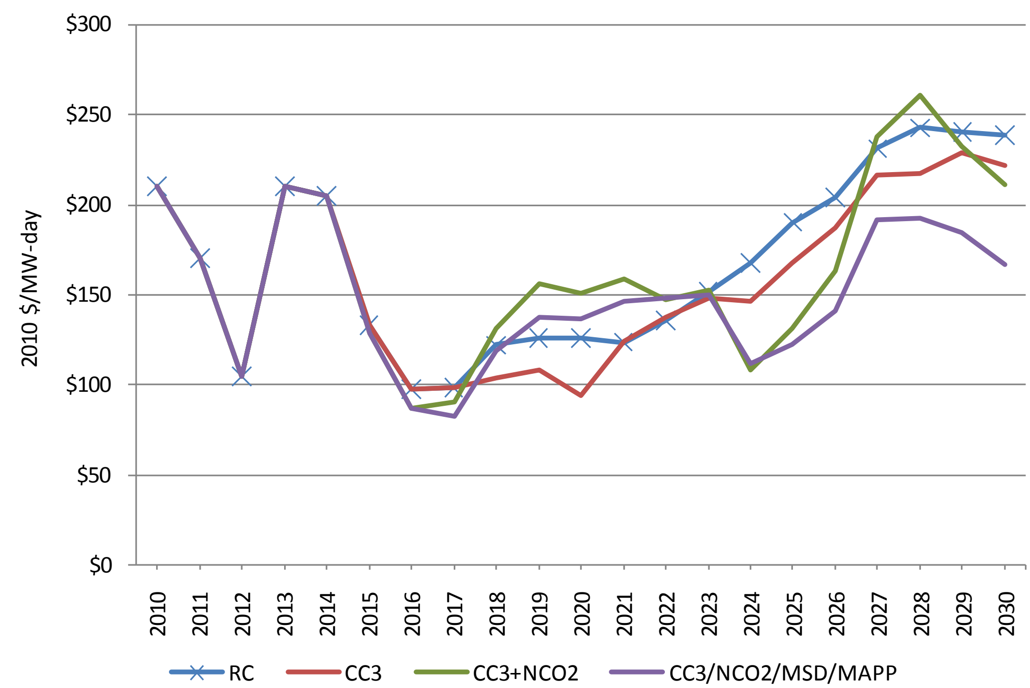


Figure 5.16 PJM-MidE Capacity Prices for Transmission Scenarios

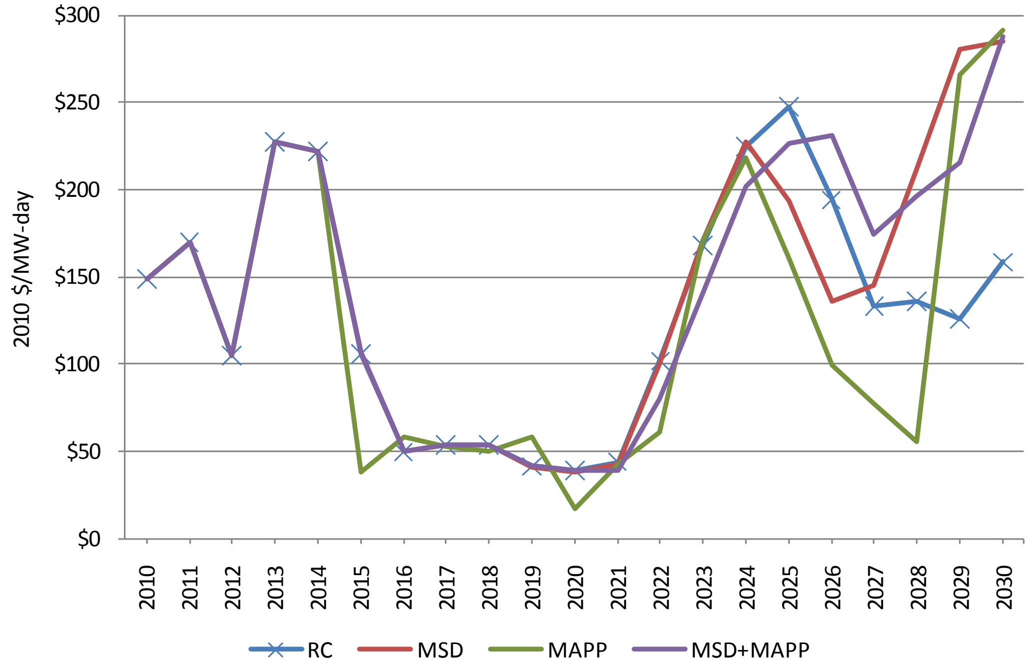
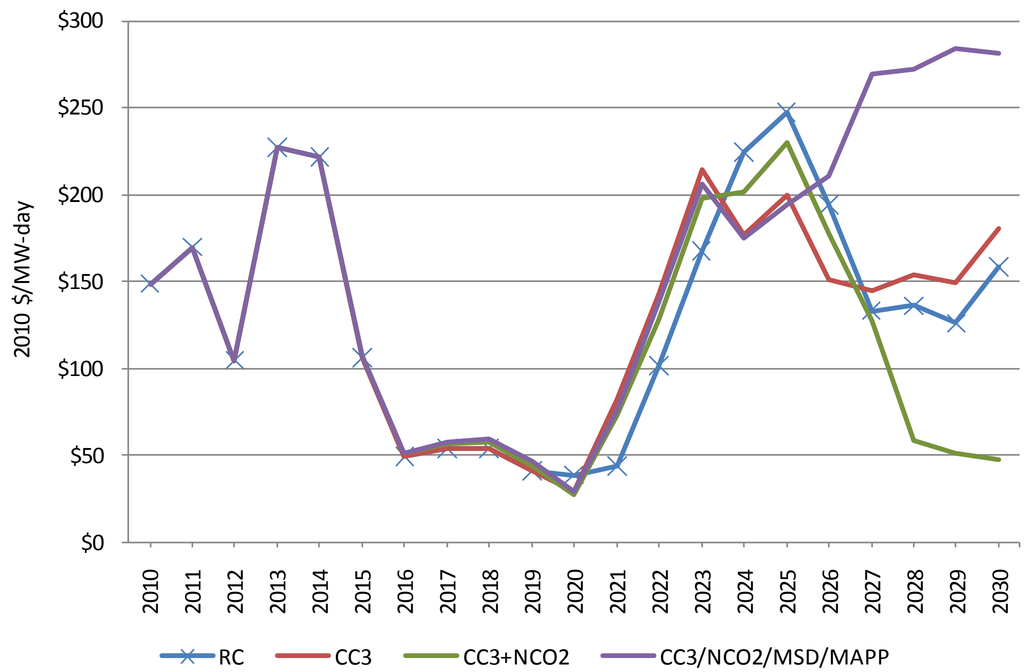


Figure 5.17 PJM-MidE Capacity Prices for CC3 Scenarios



Capacity prices in PJM-APS are almost identical to the LTER Reference Case in all the infrastructure and national carbon legislation scenarios, with only minor deviations (in real terms) over the study period.

5.7 Emissions

For Maryland plants subject to Healthy Air Act ("HAA") restrictions, there are only minor changes to emissions, as it is still more economical to run these units than to build new capacity. Except for the scenarios with a national carbon price, NO_x emissions are virtually identical to the LTER Reference Case results (see Appendix G for graphs). For the carbon price scenarios, HAA plant NO_x emissions are reduced slightly by about 200 tons per year due to reduced coal-plant capacity from retrofit de-rates. The same effect is seen in SO_2 emissions for HAA plants, with a slight reduction of about 100 tons per year due to the retrofit de-rates.

Total Maryland CO_2 emissions are significantly affected by both infrastructure changes and carbon legislation. Figure 5.18 shows the total CO_2 emissions for Maryland under the transmission scenarios. Both of the MSD scenarios have lower in-State CO_2 emissions than in the LTER Reference Case due to the increased use of imported energy. In the MAPP scenario, however, total in-State CO_2 emissions are higher, as Maryland builds extra capacity for export into PJM-MidE. As with the LTER Reference Case, under all of the transmission scenarios Maryland continues to be over the Regional Greenhouse Gas Initiative's ("RGGI") budget for the State.

Figure 5.18 Maryland CO_2 Emission for Transmission Scenarios

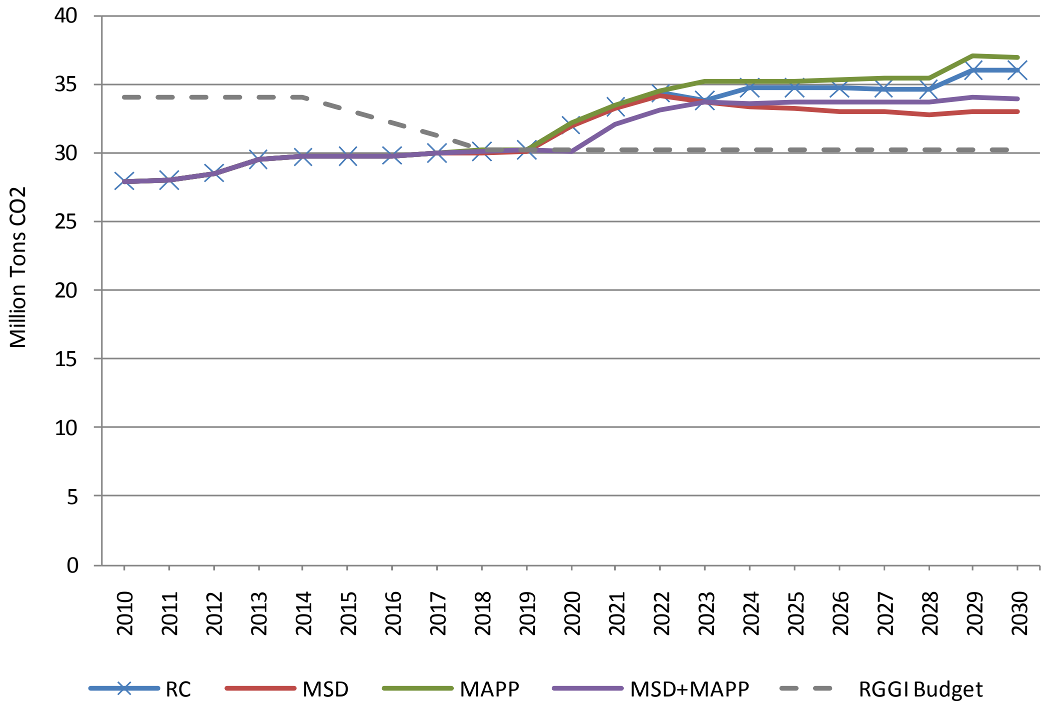
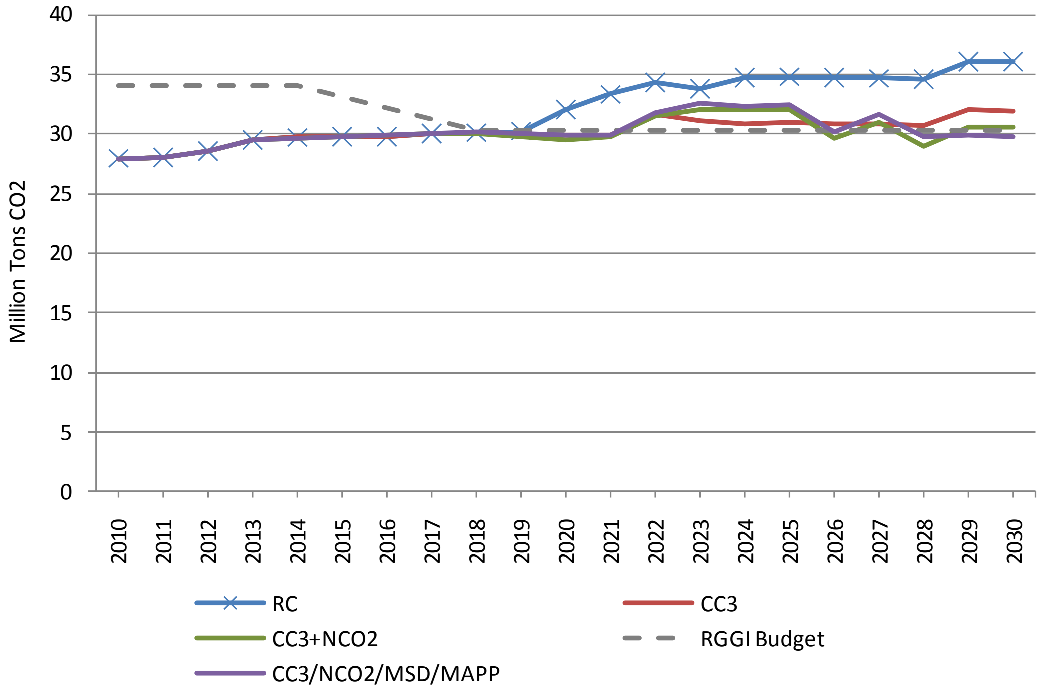


Figure 5.19, below, shows the total Maryland CO_2 emissions under the CC3 scenarios. All of these scenarios result in lower in-State CO_2 emissions. Though emissions under the CC3+NCO2 scenario dip below the RGGI budget, only the combined impacts incorporated in the CC3/NCO2/MSD/MAPP scenario result in enough CO_2 emissions reductions to remain under the RGGI budget in 2030. This is due to a combination of Calvert Cliffs 3 generation displacing new natural gas builds; national carbon legislation inducing coal plant retirements and retrofits; and the Mt. Storm to Doubs transmission upgrade facilitating greater net energy imports also reducing the need for new natural gas builds.

Figure 5.19 Maryland CO_2 Emissions for CC3 Scenarios



5.8 Results

The principal results from the analysis presented in the chapter are:

- Construction of the upgrade to the Mt. Storm to Doubs transmission line results in increased net imports for PJM-SW relative to the LTER Reference Case over the second half of the study period, but reduced net imports for PJM-MidE over the same period.

- Construction of the MAPP line facilitates greater net imports for PJM-MidE relative to the LTER Reference Case.

- The PJM-APS zone is a consistent net exporter of energy over the full 20-year study period, and net exports increase during the second half of the study period with the introduction of the Mt. Storm to Doubs transmission line.

- All scenarios that include construction of the Calvert Cliffs 3 nuclear unit result in reduced imports for PJM-SW relative to the LTER Reference Case from 2018 to 2030.

- Construction of the MAPP transmission project does not result in any difference in the new generating capacity constructed in either PJM-SW, PJM-MidE, or PJM-APS relative to new plant construction in those zones in the LTER Reference Case.
- The upgrade of the Mt. Storm to Doubs transmission line reduces new plant construction relative to the LTER Reference Case in PJM-SW but increases new plant construction in PJM-APS and PJM-MidE.
- The construction of Calvert Cliffs 3 reduces new power plant construction in PJM-SW, increases new plant construction in PJM-MidE, and does not affect total new plant construction in PJM-APS relative to the LTER Reference Case. When construction of Calvert Cliffs 3 is coupled with the introduction of national carbon legislation, new plant construction in PJM-SW increases significantly relative to the scenario with Calvert Cliffs 3 alone. Additionally, new plant construction in PJM increases from 30,100 MW under the LTER Reference Case to 35,300 MW under the CC3+NCO2 scenario.
- The combination of Calvert Cliffs 3, national carbon legislation, the Mt. Storm to Doubs line, and the MAPP line, while not affecting new plant construction in either PJM-SW or PJM-APS relative to the LTER Reference Case, does increase new plant construction in PJM-MidE (from 1,900 MW in the LTER Reference Case to 4,500 MW in the CC3/NCO2/MSD/MAPP scenario).
- Construction of Calvert Cliffs 3 does not materially affect energy prices in Maryland relative to the LTER Reference Case.
- Energy prices in Maryland are significantly affected by the introduction of national carbon legislation. By 2030, real all-hours energy prices in PJM-SW, PJM-MidE, and PJM-APS are shown to increase by approximately $21 per MWh relative to the LTER Reference Case.
- Capacity prices in PJM-SW under all three transmission scenarios (MSD, MAPP, and MSD+MAPP) track the LTER Reference Case capacity prices until 2021, then decline below the LTER Reference Case capacity prices through the end of the study period.

- CO_2 emissions in Maryland generally remain below the LTER Reference Case emissions and below the RGGI budget for those transmission scenarios that include the Mt. Storm to Doubs transmission line. For the MAPP scenarios, CO_2 emissions in Maryland are above the LTER Reference Case level beginning in 2023 and remain above the LTER Reference Case level (and the RGGI budget) through 2030.
- Maryland CO_2 emissions under all of the scenarios that include Calvert Cliffs 3 are below those of the LTER Reference Case between 2019 and 2030 but only the CC3/NCO2/MSD/MAPP ends up below the RGGI budget in 2030.

6. NATIONAL CARBON LEGISLATION ALTERNATIVE SCENARIOS

6.1 Introduction

In recent years, Congress has considered enacting legislation to restrict carbon dioxide emissions at the national level and has introduced bills aiming to establish a national-level Renewable Energy Portfolio Standard ("RPS"). While neither a national CO_2 reduction policy nor a national RPS has yet been passed, such national legislation could be put in place during the period covered in the LTER analysis. The national RPS stipulates 12 percent renewable energy by 2020. In those cases where a state already has an RPS in place, the higher of the two requirements would be in effect -- if the state RPS has higher renewable energy requirements, the state RPS would be met; if the national RPS requirement is higher, the national RPS would be met. National carbon legislation is assumed to take effect in 2015, and is based on a cap-and-trade program similar to the Waxman-Markey legislation that was introduced in 2007 but was not enacted by Congress. The assumed program allows for two billion tons of CO_2 offsets. The corresponding cost of allowances starts at $16 per ton (in 2010 dollars) of CO_2 in 2015, increasing by $1 per year through 2023, then it increases by an approximate average of $4.50 per year through 2030, for a maximum allowance of $54 per ton (in 2010 dollars) of CO_2 in 2030.

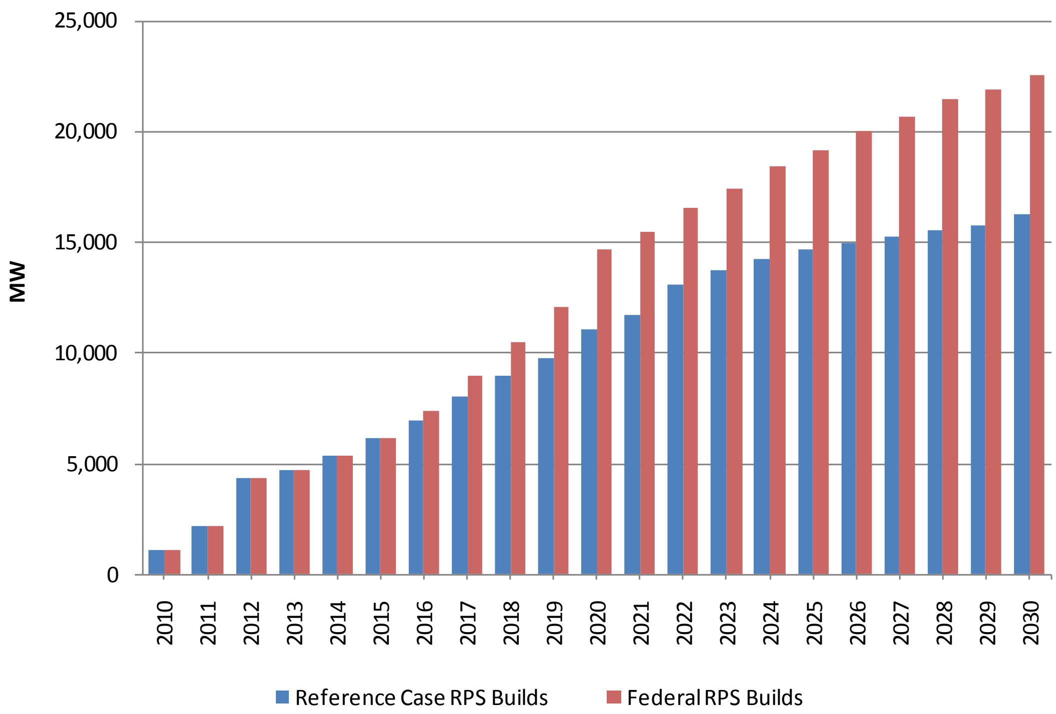
To isolate the effects of these two significant national energy policies, two alternative scenarios were run that focused only on the national carbon legislation/national renewable energy portfolio impacts. The first is a legislation alone scenario ("NCO2") and the second is legislation along with the construction of the Mt. Storm to Doubs line ("NCO2+MSD"), which is put in-service in 2015. This chapter compares the NCO2 scenario results with the LTER

Reference Case ("RC") and the NCO2+MSD scenario results to the Mt. Storm to Doubs alone alternative scenario ("MSD").

6.2 Capacity Retirements and Additions

To comply with a national RPS, the required level of renewable capacity additions in PJM will be greater than the level established for the LTER Reference Case, which is solely based on meeting state RPSs (refer to Chapter 4 for RC RPS input assumptions). Under the NCO2 scenarios, cumulative RPS capacity additions in PJM reach 22,541 MW through 2030, which is 6,285 MW (in 2030) more than under the LTER Reference Case assumptions (see Figure 6.1).

Figure 6.1 Renewable Energy Capacity Additions



Maryland RPS capacity additions are not affected by the implementation of the federal RPS, as Maryland's RPS requirements are higher than the 12 percent federal standard and Maryland continues to source the majority of its renewable energy from lower-cost out-of-State resources.

As with all other scenarios, age-based retirements are unchanged from the LTER Reference Case. However, under the NCO2 scenarios, economic-based plant retirements are slightly higher when compared to the LTER Reference Case and the MSD scenario. As indicated in Chapter 5, under both the LTER Reference Case and the MSD scenario, economic retirements account for a total of 315 MW of PJM-wide economic retirements throughout the study period. As shown in Table 6.1 below, economic-based retirements account for 717 MW from 2016 to 2018 under the NCO2 scenarios. The NCO2+MSD scenario includes the retirement of two plants in 2019, one that accounts for 137 MW and another that accounts for 244 MW, while the NCO2 alone scenario includes the retirement of only the 137 MW plant in 2019.

Table 6.1
NCO2 Scenarios Economic-Based Plant Retirements (MW)

Year	LTER Reference Case and MSD	NCO2	NCO2+MSD
2016	194	206	206
2017	27	121	121
2018	0	390	390
2019	0	137	381
2020	94	0	0
Total Through 2030	315	855	1099

As displayed in the table above, the modeling results indicate that no other plants will retire for economic-based reasons after 2020 through the remainder of the study period. However, the implementation of national carbon legislation prompts 28 coal-burning facilities in PJM to install carbon-sequestration technologies between 2026 and 2030. These retrofits cause each facility to lose approximately 33 percent of their generating capacity. In addition to the reduced energy production as a result of the capacity de-rate, each plant experiences a decreased level of efficiency due to an increase in heat rate. Therefore, the total energy production lost due to the carbon sequestration technology is greater than just accounted for by the 33 percent reduction in capacity. The retrofits result in approximately 4,800 MW of generating capacity lost due to plant capacity de-rates, in both the NCO2 and the NCO2+MSD scenarios.

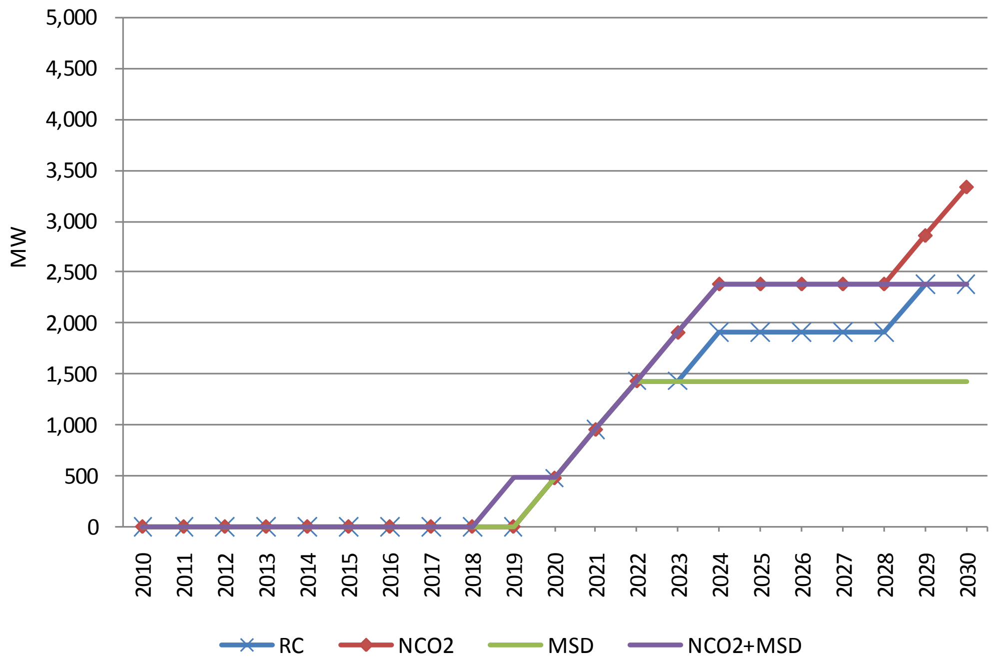
In comparison to the LTER Reference Case and the MSD scenario, the NCO2 scenarios result in about 7,000 MW of additional PJM-wide natural gas power plant additions (see Table 6.2 below). This additional capacity is built because economic natural gas resources displace coal resources in PJM. Although some of this displacement is linked to economic-based retirements of coal plants, the majority of the additional natural gas plants are needed to compensate for the reduced energy production associated with retrofitting coal plants to decrease carbon emissions. Note that the increase in new power plants does not occur until the later years of the study period when the carbon emissions allowances become relatively more expensive.

Table 6.2
Cumulative Natural Gas Capacity Additions in PJM (MW)

Year	RC	NCO2	MSD	NCO2+MSD
2018	477	477	477	477
2019	954	954	954	1,431
2020	1,908	1,908	1,908	1,908
2021	3,339	2,862	3,339	2,862
2022	4,770	4,770	5,247	5,724
2023	7,155	7,632	7,155	7,632
2024	9,540	10,017	9,540	10,017
2025	10,971	11,448	11,448	11,448
2026	13,356	13,704	13,356	14,399
2027	16,218	17,132	16,089	17,480
2028	19,950	23,209	20,297	23,254
2029	24,938	30,240	24,983	30,066
2030	30,101	37,181	30,145	37,355

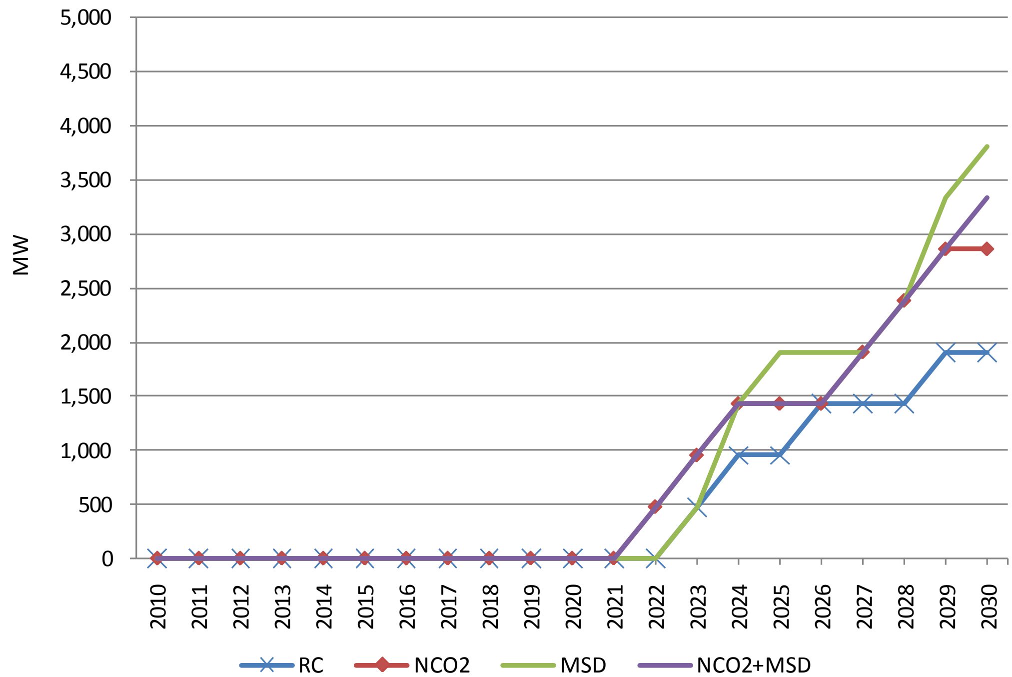
For each of the NCO2 scenarios, the modeling results indicate that through 2030, two additional generic combined cycle plants are constructed in PJM-SW (see Figure 6.2 below). In the LTER Reference Case, five natural gas plants are constructed in PJM-SW while seven plants are constructed in the NCO2 alone scenario, through 2030. In the MSD alone scenario, three plants are constructed in PJM-SW while five are constructed in the NCO2+MSD scenario, through 2030. These incremental increases in capacity additions in the NCO2 scenarios as compared to the LTER Reference Case capacity builds, are mainly attributable to the additional generation needed in PJM-SW following the retrofit de-rates. Plant additions in the MSD scenarios are lower overall due to the increased imports available through the upgraded transmission line.

Figure 6.2 PJM-SW Natural Gas Capacity Additions



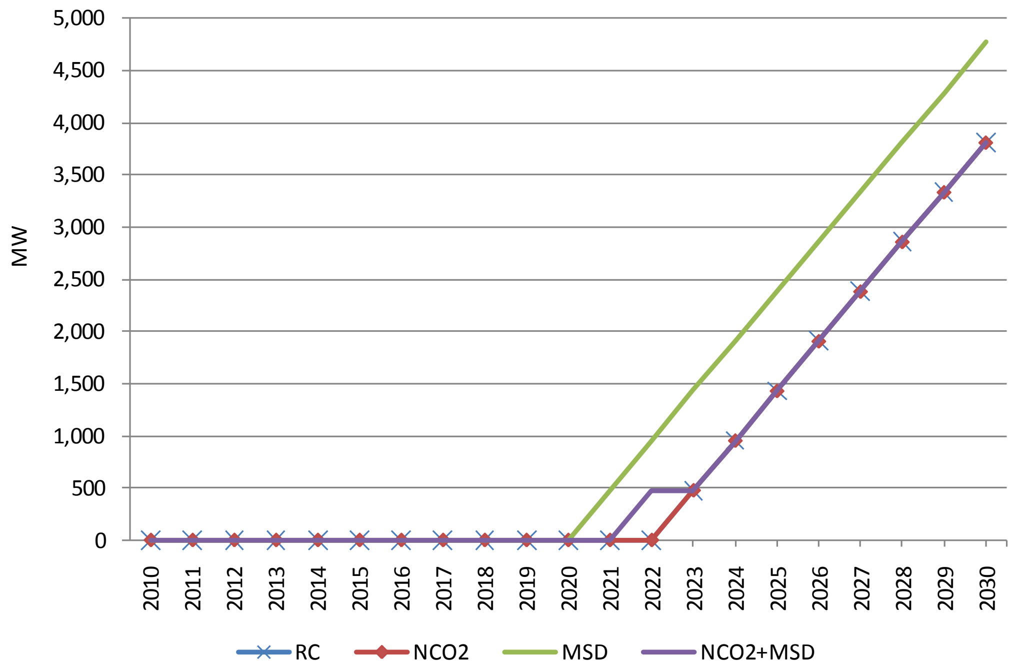
As with PJM-SW, under the NCO2 scenario two additional combined cycle natural gas plants are built in PJM-MidE by 2030, relative to the LTER Reference Case (see Figure 6.3 below). As discussed in Chapter 5, the MSD line reduces the availability of imports into the PJM-MidE, therefore under NCO2+MSD another additional natural gas plant is constructed in PJM-MidE relative to NCO2 alone. However, relative to MSD alone, one fewer natural gas addition is required under NCO2+MSD, as more capacity in this scenario is built in PJM-SW and, therefore, slightly more imports into PJM-MidE are available.

Figure 6.3 PJM-MidE Natural Gas Capacity Additions



As PJM-APS is a lower-cost exporting zone, there is no change in natural gas builds between the LTER Reference Case and the NCO2 scenarios (see Figure 6.4 below). Under the MSD alone scenario builds are slightly higher in PJM-APS because of the increased opportunity to export into PJM-SW. The builds under MSD alone compared to the NCO2+MSD scenario are greater in PJM-APS, as more capacity is added in PJM-SW under NCO2+MSD thereby reducing PJM-SW's need for imports.

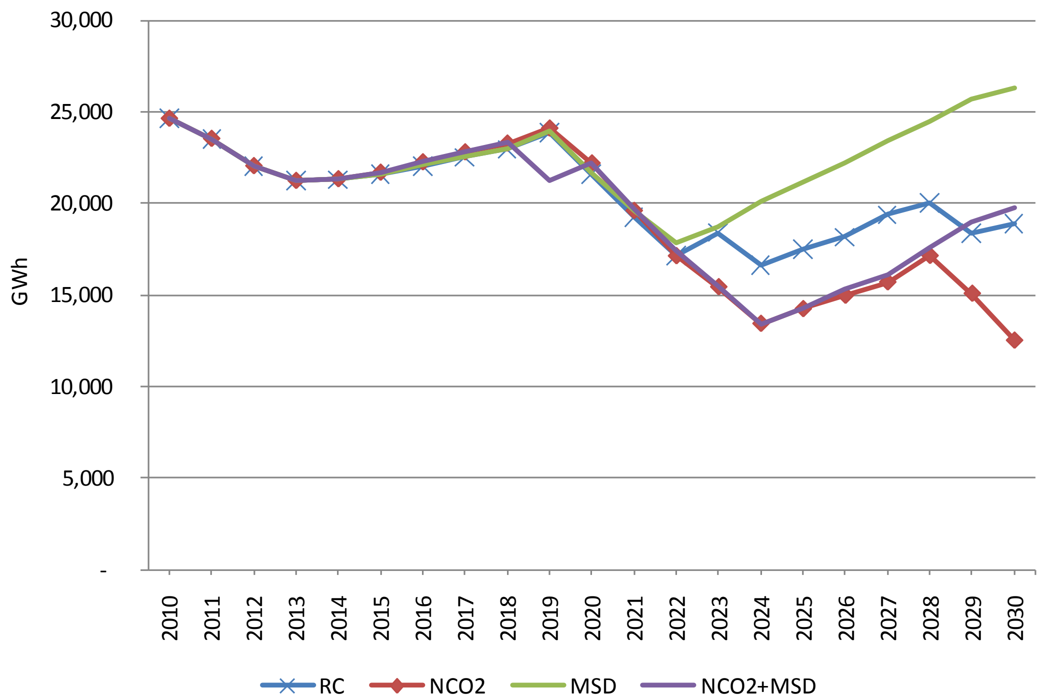
Figure 6.4 PJM-APS Natural Gas Capacity Additions



6.3 Net Energy Imports

Net imports are affected by the introduction of national carbon legislation due mainly to the capacity retrofit de-rates and increased retirements resulting in more incremental capacity being built in PJM-SW. Figure 6.5, below, shows the net imports for PJM-SW. Net imports into PJM-SW are lower under the NCO2 alone scenario compared to the LTER Reference Case, as more of the load growth is met by natural gas capacity additions. Under MSD alone, PJM-SW net imports are higher than in the LTER Reference Case due to the increased transfer capacity from PJM-APS facilitated by the transmission upgrade. PJM-SW net imports under the NCO2+MSD scenario converge towards the LTER Reference Case result in the last few years of the study period as the effects of the two tend to run counter to each other, i.e. national carbon legislation increases zonal builds thereby decreasing imports while the Mt. Storm to Doubs line increases import capacity thereby decreasing zonal builds.

Figure 6.5 PJM-SW Net Imports



In the PJM-MidE and PJM-APS zones (see Figure 6.6 and Figure 6.7 below), the modeling results indicate similar trends—when comparing the NCO2 scenarios to the LTER Reference Case and MSD, the change in energy imports reflects the change in capacity additions and import/export capabilities in each zone.

Figure 6.6 PJM-MidE Net Imports

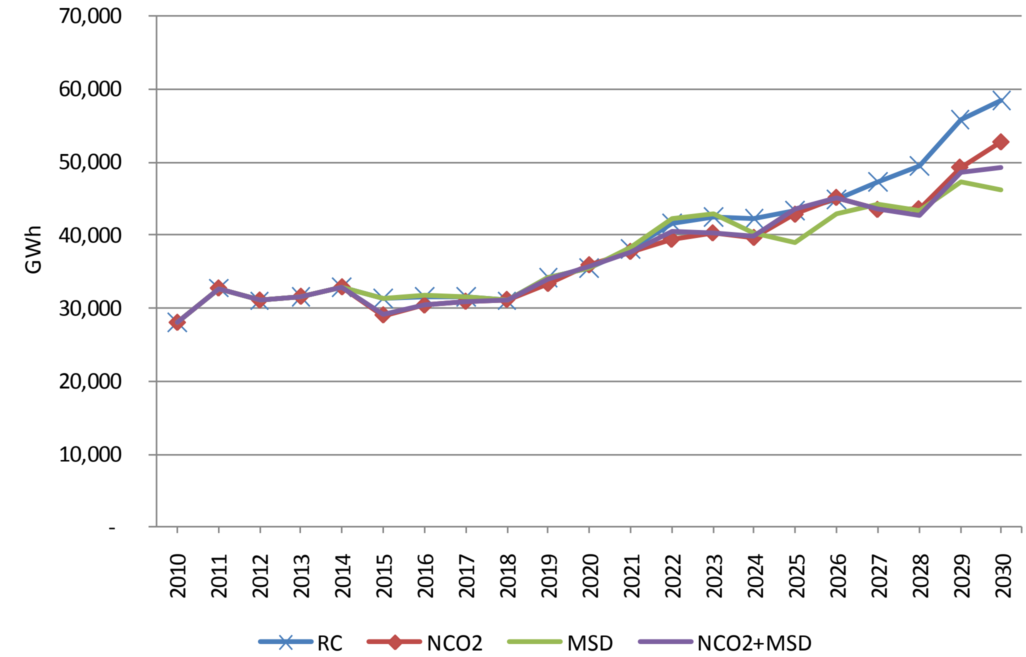
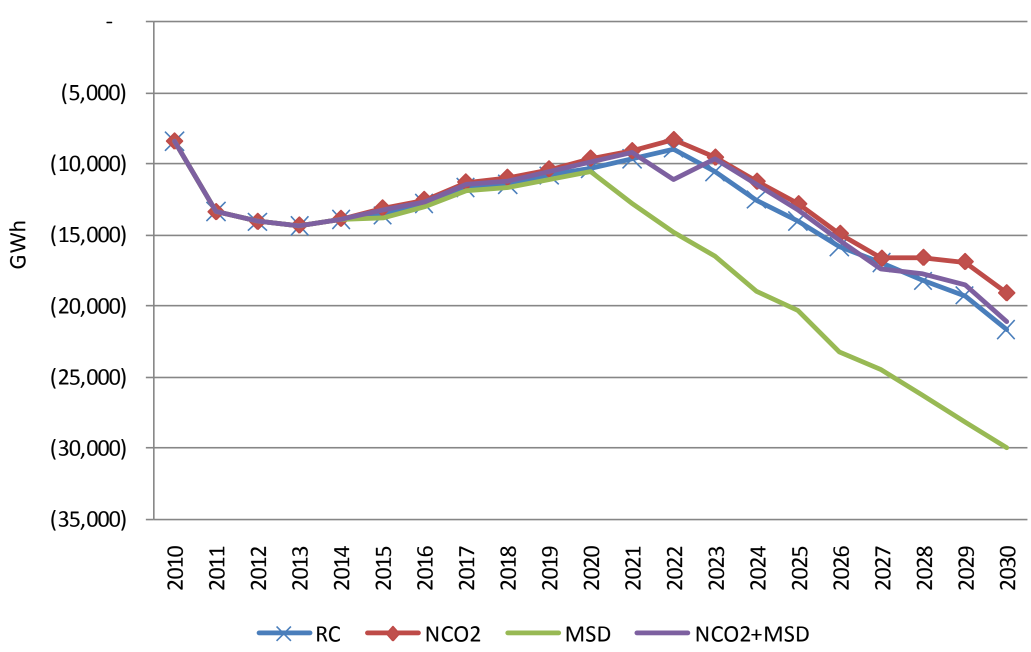


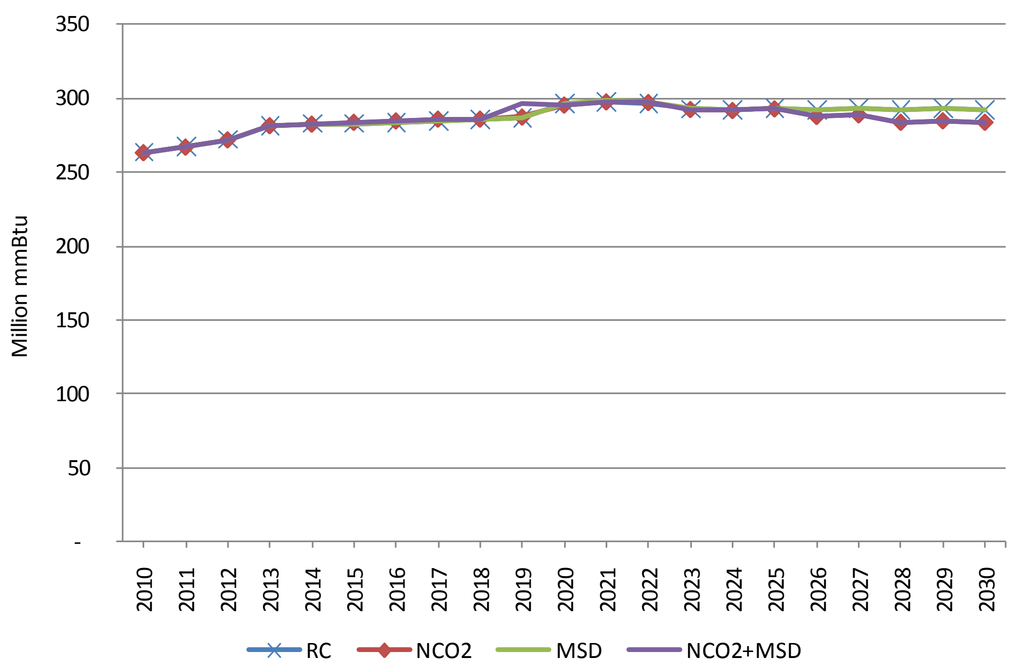
Figure 6.7 PJM-APS Net Imports



6.4 Fuel Use

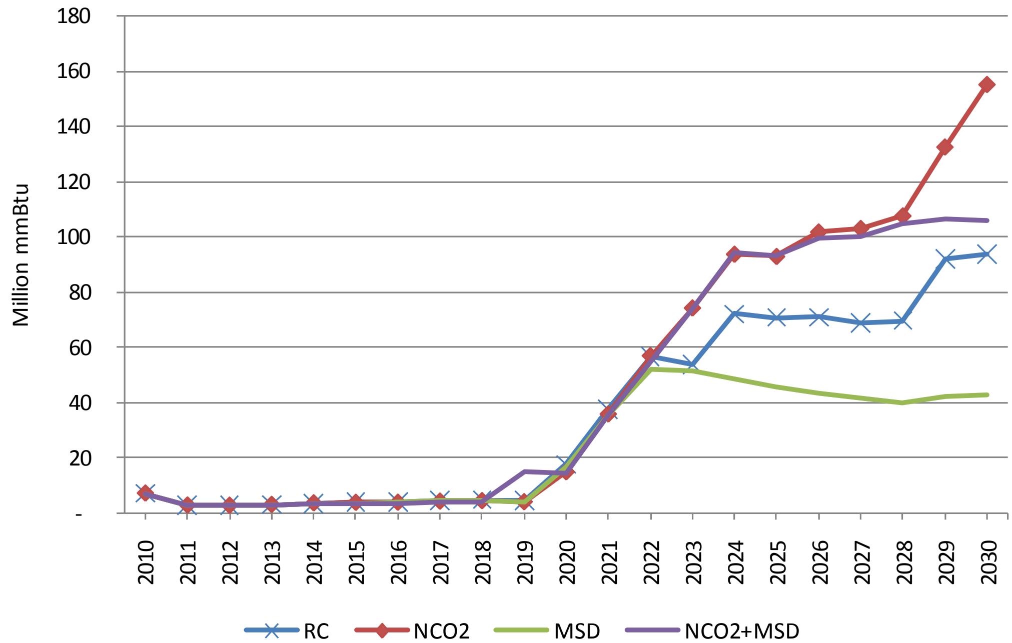
Under both of the NCO2 scenarios there is a small reduction (about 3 percent) in coal consumption for electricity generation in Maryland by 2030 (see Figure 6.8 below). This is due to a reduction in coal-fired generating capacity associated with retrofit de-rates.

Figure 6.8 Coal Use for Electricity Generation in Maryland



Natural gas consumption in Maryland is significantly affected by the introduction of national carbon legislation (see Figure 6.9 below), due to the additional incremental natural gas capacity additions under those scenarios. As with the natural gas capacity builds, the effects of national carbon legislation and the Mt. Storm to Doubs transmission upgrade tend to counteract each other. Under the NCO2+MSD scenario natural gas use for electricity generation falls between the MSD alone and NCO2 alone scenario results and converges towards the LTER Reference Case result.

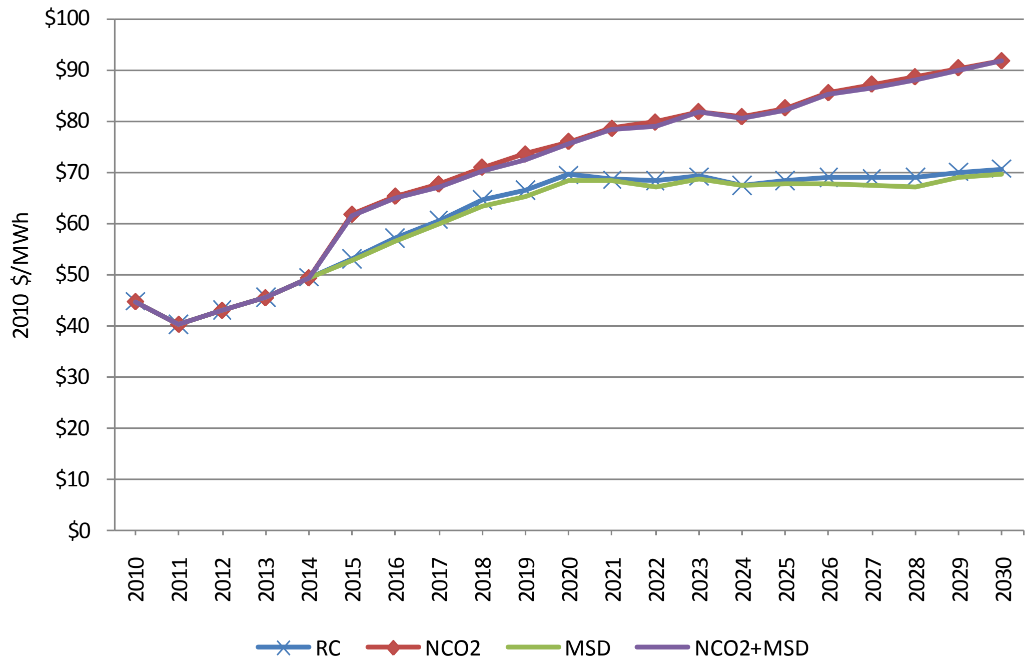
Figure 6.9 Natural Gas Consumption for Electricity Generation in Maryland



6.5 Energy Prices

Under MSD alone, the effect on energy prices is minimal compared to the LTER Reference Case. National carbon legislation, however, has a significant impact on energy prices. The legislation is reflected in the wholesale energy price increases beginning in 2015 (the year the carbon legislation takes effect), which become more pronounced in the later years of the study period, as the carbon emission allowances become more expensive. Figure 6.10, Figure 6.11, and Figure 6.12 show the price impacts (in 2010 dollars) for the PJM-SW, PJM-MidE, and PJM-APS zones.

Figure 6.10 PJM-SW Real All-Hours Energy Prices



For both of the NCO2 scenarios, energy prices increase by approximately 16 percent in PJM-SW between 2014 and 2015, when compared to the LTER Reference Case and MSD and about 13 percent in PJM-MidE (Figure 6.11 below) and 16 percent in PJM-APS (Figure 6.12 below). By 2030, the relative price increase in PJM-SW is approximately 31 percent, and about 30 percent and 34 percent in PJM-MidE and PJM-APS, respectively. These price increases are related to emissions allowance prices that increase to $54 per ton of CO_2 by the final year of the study period.

Figure 6.11 PJM-MidE Real All-Hours Energy Prices

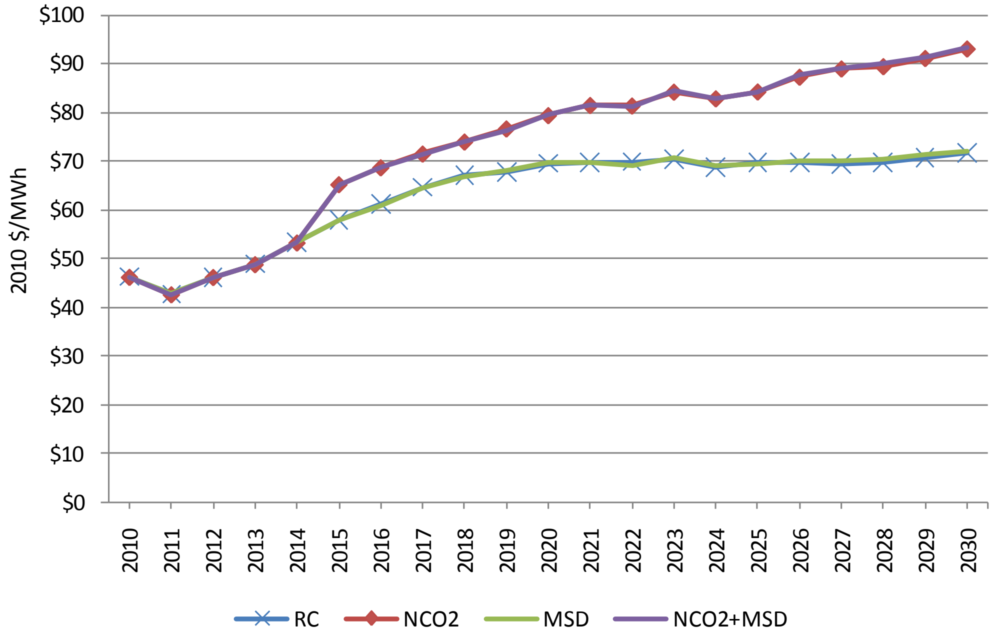
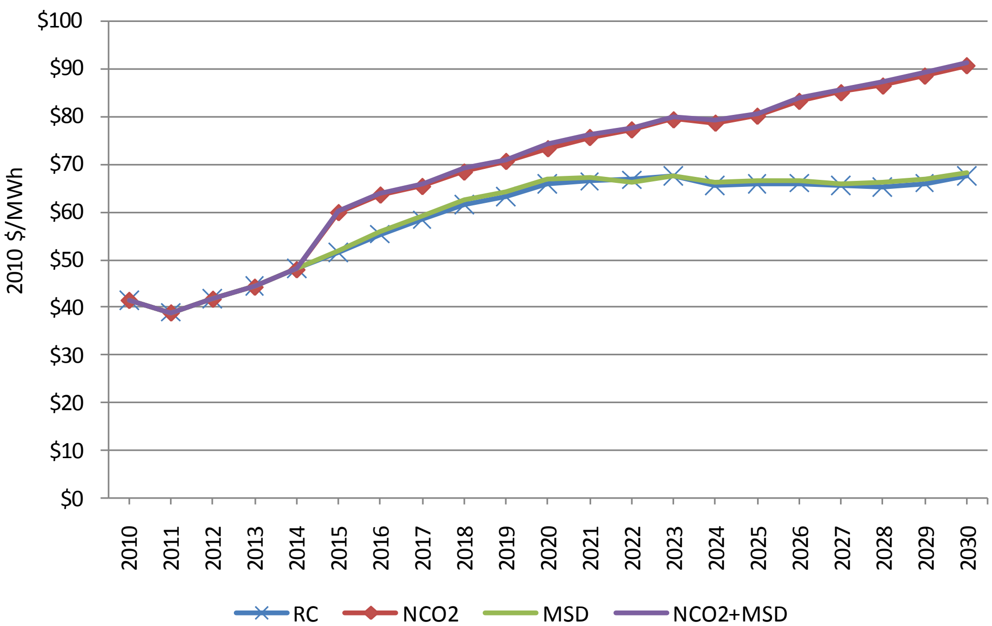


Figure 6.12 PJM-APS Real All-Hours Energy Prices



6.6 Capacity Prices

Capacity prices in PJM-SW under the national carbon legislation assumptions, shown in Figure 6.13 below, track the LTER Reference Case capacity prices through 2022. After 2022, differences in capacity prices emerge related to imports into PJM-SW and the plant build-out schedule. The PJM-SW capacity costs associated with the NCO2 scenarios are below the LTER Reference Case capacity costs over the second half of the study period, which closely matches the differences in the power plant build-out schedule. Under the NCO2 alone scenario, PJM-SW sees a higher level of natural gas power plant construction relative to the LTER Reference Case starting in 2023, which matches the difference in capacity costs over the same period.

Capacity prices in the NCO2+MSD scenario show no consistent relationship to the capacity costs for the MSD scenario. While there are fewer plants built under the MSD scenario than the NCO2+MSD scenario, there are lower levels of imports under the NCO2+MSD scenario than under the MSD scenario. The opposite directions of the two influences on capacity costs result in the inconsistent relationship in capacity prices between these two scenarios.

Figure 6.13 PJM-SW Capacity Prices

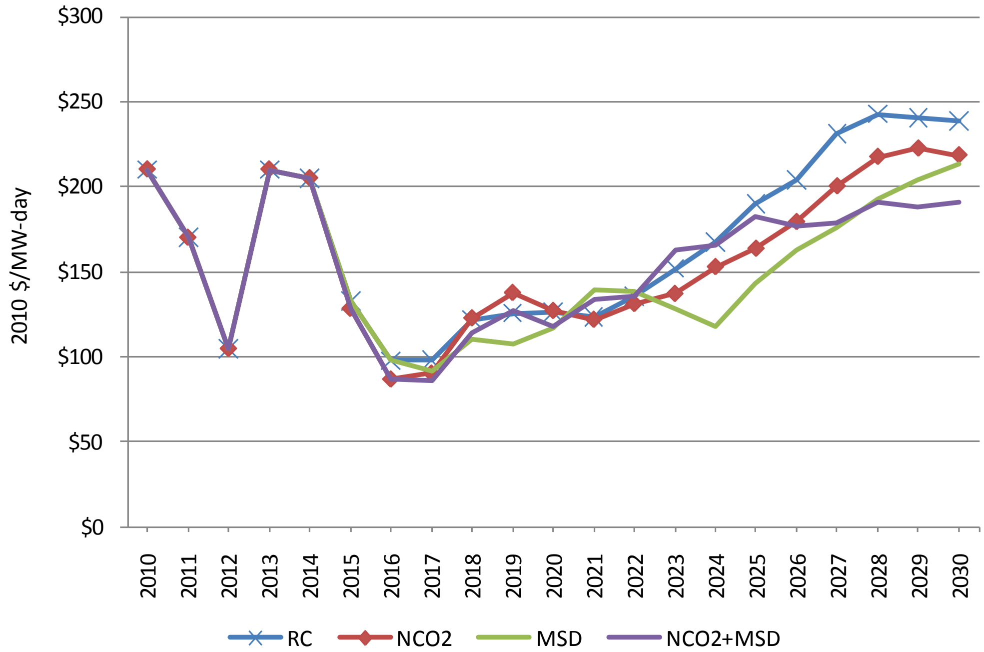
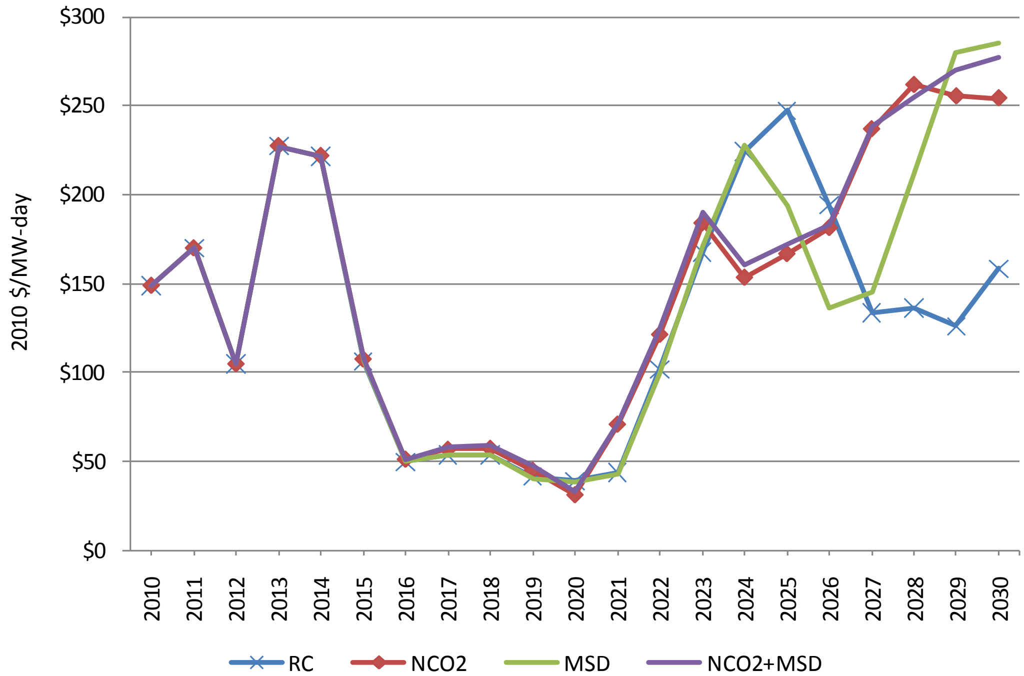


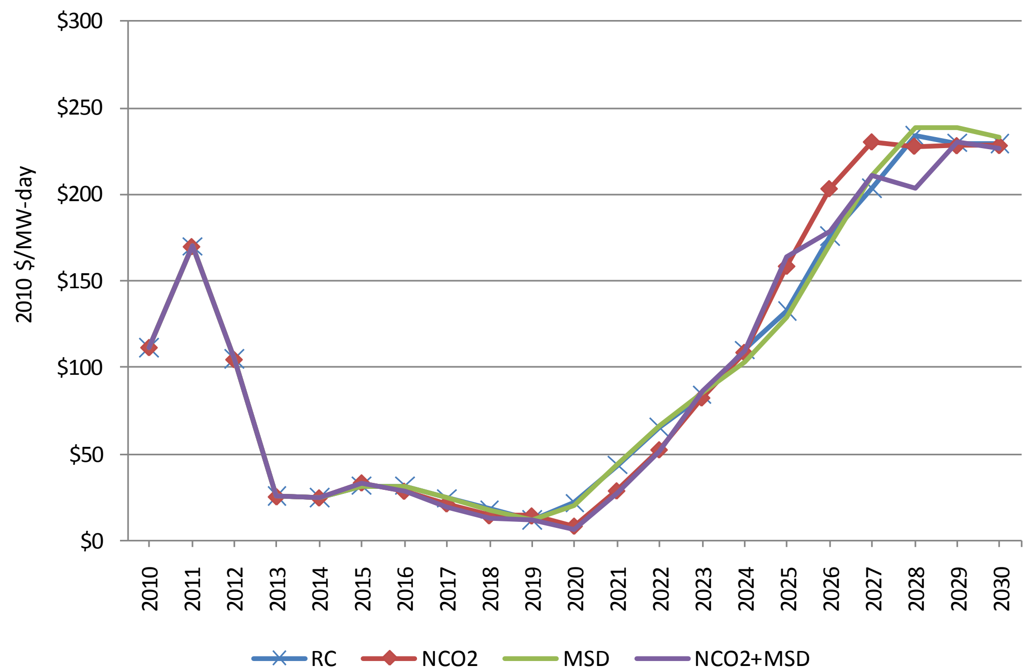
Figure 6.14, below, shows the capacity costs in the PJM-MidE area. As was the case for capacity prices in PJM-SW, capacity prices in PJM-MidE exhibit little differences among the scenarios until the early to mid-2020s. Throughout the period, both of the national carbon legislation scenarios track together, with the exception of 2030, when the NCO2+MSD scenario increases relative to the NCO2 alone scenario. This difference relates to the construction of an additional natural gas plant in the NCO2+MSD scenario in that year. The movement in the RC and the MSD scenarios is tied to power plant construction schedules.

Figure 6.14 PJM-MidE Capacity Prices



There is little difference in the capacity prices under any of the examined scenarios in PJM-APS, as shown in Figure 6.15 below. This result stems from there being little difference in the build-out schedule for power plants in PJM-APS under the four scenarios considered.

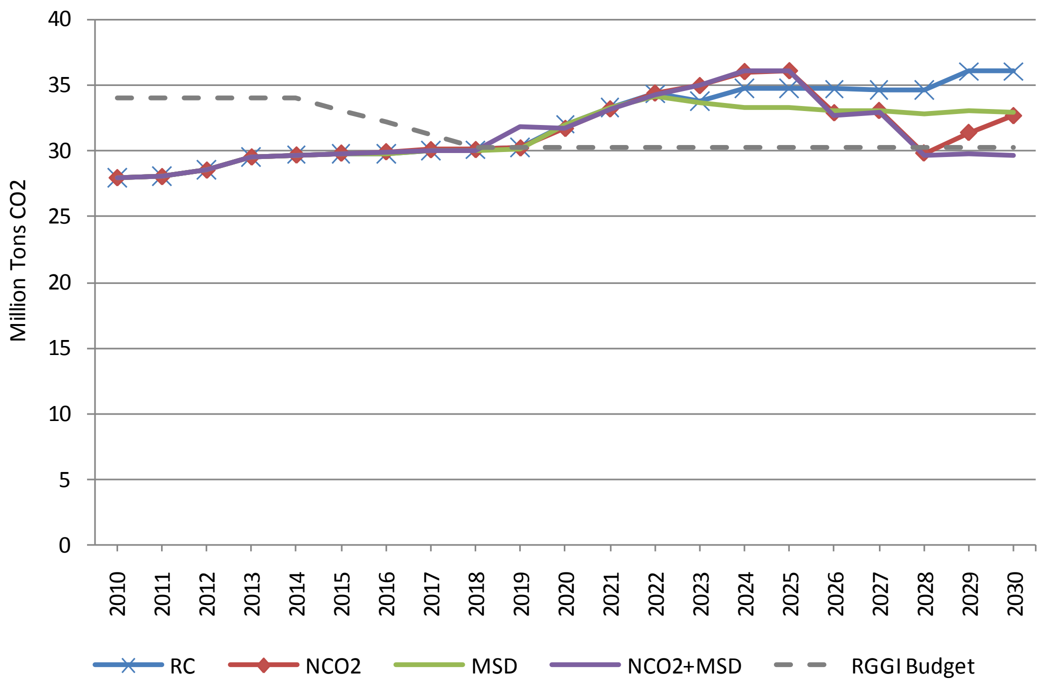
Figure 6.15 PJM-APS Capacity Prices



6.7 Emissions

Under the NCO2 scenarios, SO_2 and NO_x emissions from plants subject to the Maryland Healthy Air Act ("HAA") are minimally affected in comparison to the LTER Reference Case, as these plants remain the least-cost source of energy for the State. Total in-State Maryland CO_2 emissions however, are affected by both the national carbon legislation and increased in imports (and hence, decrease in new capacity additions) facilitated by the Mt. Storm to Doubs transmission upgrade. Figure 6.16, below, shows the Maryland CO_2 emissions under the LTER Reference Case, the MSD alone scenario, and the NCO2 scenarios. In 2026 and again in 2028, the level of carbon emissions in Maryland decreases, as retrofits begin to affect coal-fired generation. Under the NCO2 alone scenario, carbon emissions begin to increase again 2029, which is due to the increase in natural gas consumption resulting from the natural gas capacity addition that year. At the end of the study period, Maryland's in-State CO_2 emissions are about 10 percent lower than in the LTER Reference Case under the national carbon legislation scenarios. Only the combination of coal plant retirements and retrofits from national carbon legislation and the increased net energy imports facilitated by the Mt. Storm to Doubs transmission line (reducing the need to build new natural gas capacity) provide enough emissions reductions to bring Maryland into compliance with the State's Regional Greenhouse Gas Initiative's CO_2 budget.

Figure 6.16 Maryland CO_2 Emissions



6.8 Results

The key results obtained from the analysis of the scenarios containing the assumption of national carbon legislation combined with a national RPS are presented below:

- The scenarios that include national carbon legislation result in power plant additions of 37,200 MW (NCO2 scenario) and 37,400 MW (NCO2+MSD scenario), compared to the LTER Reference Case additions of 30,100 MW. These plant additions are natural gas plants that displace coal-fired plants.
- In PJM-SW, approximately 1,000 MW of capacity is added under the national carbon legislation scenario assumptions above the level of capacity added under the LTER Reference Case. This difference does not emerge until the final two years of the study period.
- Under the NOC2+MSD scenario, 1,000 MW of capacity is added in PJM-SW above the level of capacity added under the MSD scenario (excluding national carbon legislation). This difference is evident over the last seven years of the study period. In 2029 and 2030, the cumulative additions in the NCO2+MSD scenario are equivalent to those in the LTER Reference Case.
- In PJM-MidE, both of the scenarios that include national carbon legislation are characterized by greater levels of new capacity additions than shown for the LTER Reference Case.
- Under the NCO2 scenarios, 22,500 MW of renewable resources are added to PJM, compared to 16,300 in the LTER Reference Case.
- Under the NCO2 scenarios, between 850 and 1,100 MW of fossil fuel facilities are retired in PJM over the 20-year study period, compared with 300 MW under the LTER Reference Case.
- In both of the NCO2 scenarios, Maryland's generation mix becomes more heavily gas-fired and less heavily coal-fired.
- Real all-hours energy prices increase by about $21 per MWh by 2030 for the NCO2 scenarios for PJM-SW, PJM-MidE, and PJM-APS.
- In PJM-SW, capacity prices under the NCO2 scenarios are between $20 and $50 per MW-day lower than in the LTER Reference Case in 2030, but track LTER Reference Case capacity prices through 2022.

- In PJM-MidE, capacity prices under the NCO2 scenarios track capacity prices under the LTER Reference Case through 2023, then the capacity prices are above those shown for the LTER Reference Case.
- In PJM-APS, neither of the two NCO2 scenarios exhibit capacity prices very different from those shown for the LTER Reference Case.
- Maryland CO_2 emissions in the NCO2 scenarios are below the LTER Reference Case levels after 2025 when retrofits begin. In the last three years of the study period, in-State CO_2 emissions for Maryland are below the RGGI budget for the NCO2+MSD scenario.

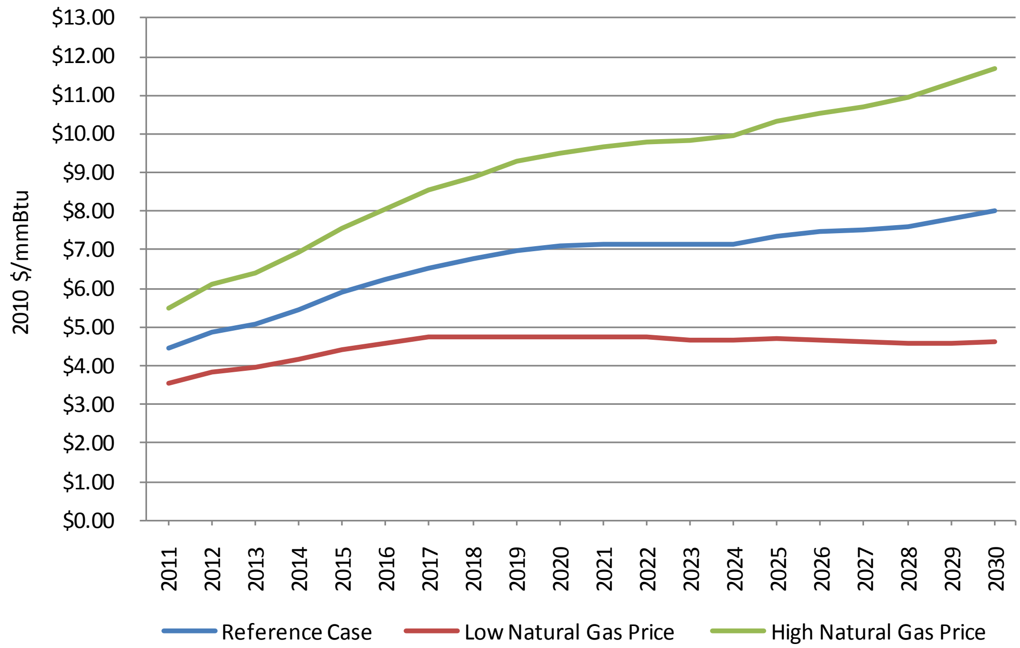
7. HIGH AND LOW NATURAL GAS PRICE ALTERNATIVE SCENARIOS

7.1 Introduction

The price of natural gas is one of the most important drivers of wholesale electricity prices. To explore the effect of changes to the natural gas price assumptions developed for the LTER Reference Case, several alternative scenarios were developed using a high priced natural gas forecast and a low priced natural gas forecast. The natural gas price forecasts in this analysis are based on the Henry Hub, the most liquid natural gas hub in the United States, with prices adjusted upward to account for the cost of transporting the natural gas from the Henry Hub to the region where the generator is located.

Average natural gas prices in the Low Price Natural Gas scenario start at $3.56 per mmBtu in 2011 and rise to $4.63 by 2030, while in the High Price Natural Gas scenario, average natural gas prices start at $5.50 per mmBtu in 2011 and increase to $11.70 per mmBtu by 2030, compared to the LTER Reference Case natural gas price forecast which begins at $4.46 per mmBtu and ends at $8.01 per mmBtu (see Chapter 3, Section 3.4 for a detailed discussion of the natural gas price assumptions). Figure 7.1, below, presents the average annual natural gas prices for the LTER Reference Case, the Low Price Natural Gas ("LPNG") scenarios, and the High Price Natural Gas ("HPNG") scenarios. The natural gas price scenarios were also ran with the Mt. Storm to Doubs transmission upgrade ("LPNG+MSD" and "HPNG+MSD").

Figure 7.1 Forecast of the Average Annual Natural Gas Price at the Henry Hub



7.2 Net Energy Imports

PJM-SW net imports are shown in Figure 7.2 and Figure 7.3, both below. Net energy imports are slightly lower under LPNG compared to the LTER Reference Case in the last four years of the study period, as PJM-SW begins to build new capacity. Net imports under HPNG are higher and converge towards the long-run LTER Reference Case result at the end of the study period as transmission transfer capacity is fully utilized. Net imports are higher than the LTER Reference Case under the scenarios with the Mt. Storm to Doubs transmission upgrade as this line facilitates increased energy imports from PJM-APS. However, PJM-SW net imports under HPNG+MSD are lower than for MSD alone or for LPNG+MSD as exports into PJM-MidE increase slightly due to PJM-SW being a lower-cost zone for adding capacity.

Figure 7.2 PJM-SW Net Imports for Alternative Gas Price Scenarios

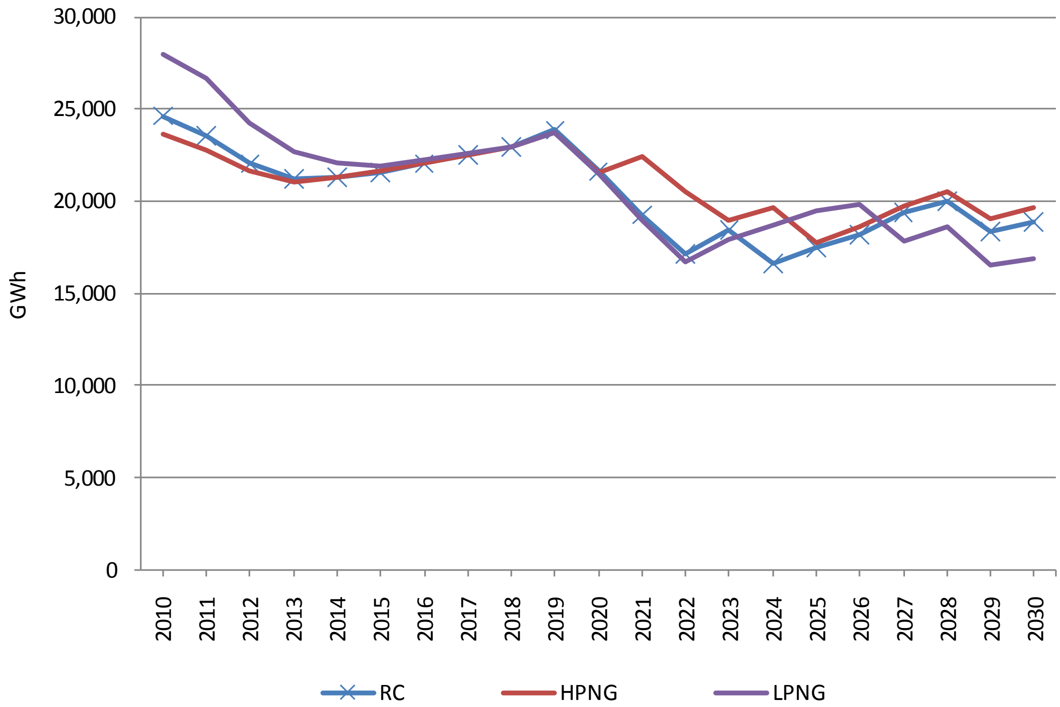
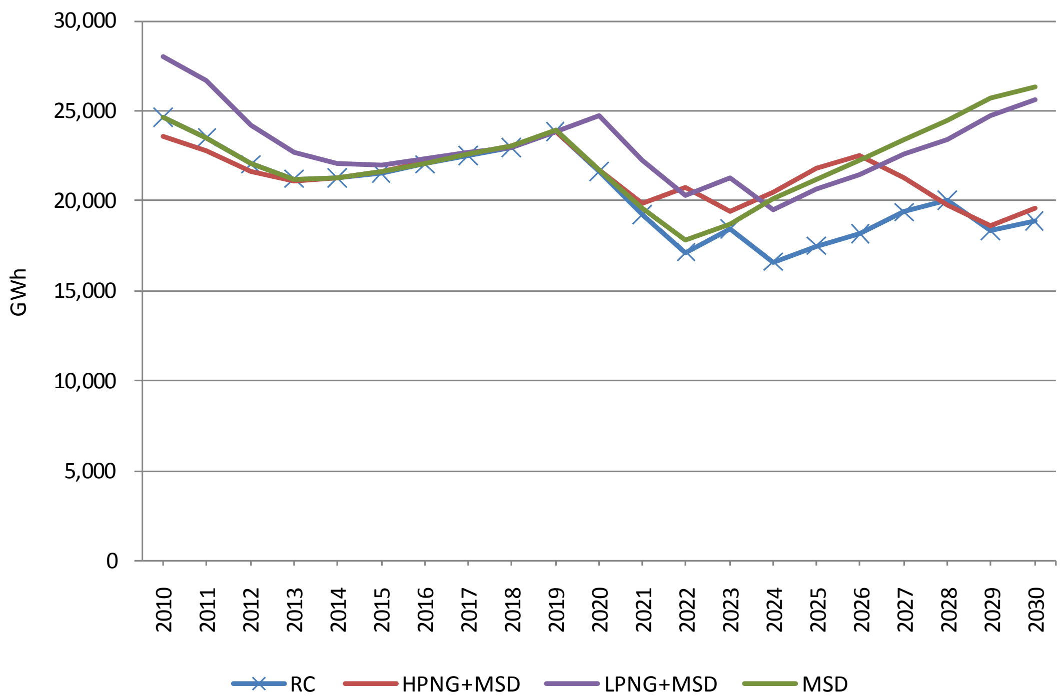
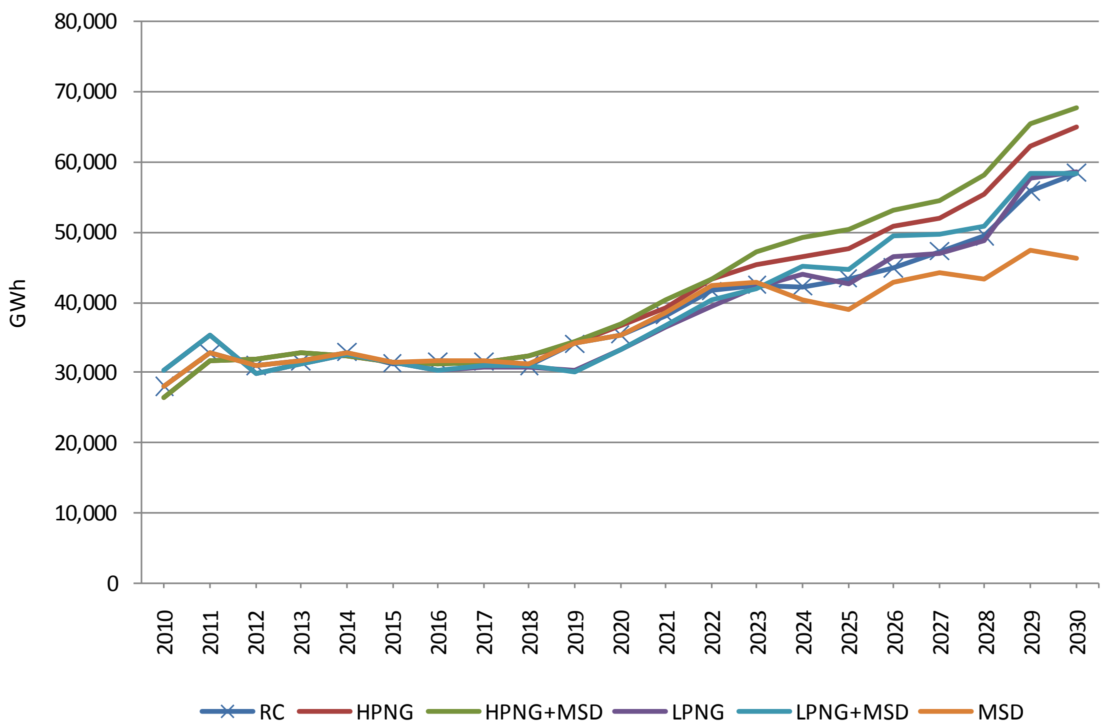


Figure 7.3 PJM-SW Net Imports for Alternative Gas Price and MSD Scenarios



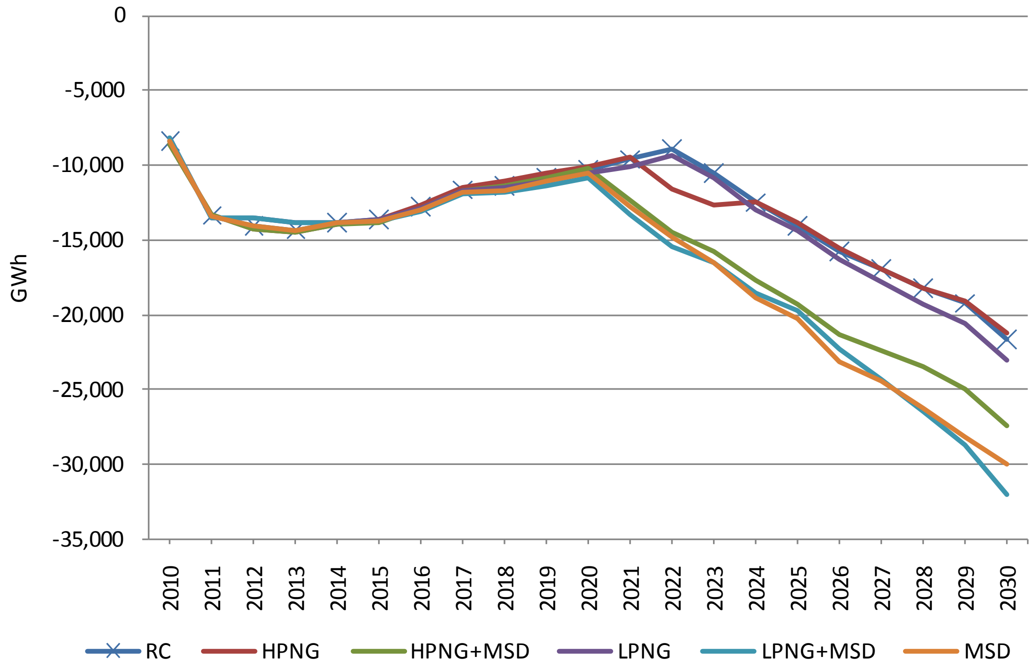
Net energy imports in PJM MidE increase under all scenarios (see Figure 7.4 below) and are very similar to the LTER Reference Case under the scenarios with a lower natural gas price. Net imports to PJM-MidE are lowest in the MSD alone scenario as PJM-SW builds less capacity in that scenario (see Chapter 5). PJM-SW, however, is a lower-cost zone compared to PJM-MidE and therefore, under the scenarios with higher natural gas prices, new capacity is built first in PJM-SW and sold into PJM-MidE leading to higher PJM-MidE net imports in that zone.

Figure 7.4 PJM-MidE Net Imports



PJM-APS remains a strong net exporter under all scenarios (see Figure 7.5 below), with exports increasing significantly with the addition of the Mt. Storm to Doubs transmission upgrade. PJM-APS exports are less affected by changes in the natural gas prices, as PJM-APS is still a lower-cost zone for new capacity additions, compared to PJM-SW and PJM-MidE.

Figure 7.5 PJM-APS Net Imports



7.3 Plant Retirements and Additions

Economic generating plant retirements are marginally affected by the change in natural gas prices. In the LTER Reference Case, 315 MW of capacity retired due to economics. Under lower natural gas prices, 327 MW of capacity retires due to economics, and under higher natural gas prices 117 MW of capacity retires. The Mt. Storm to Doubs transmission upgrade has no effect on economic retirements. Other factors held constant, high natural gas prices, which result in upward pressure on market energy prices, favorably affect the economics of coal-fired facilities.

The differences in natural gas prices between the HPNG scenario and the LPNG scenario affects the selection of the types of plants built in PJM to meet growing loads and to replace the generating capacity lost from retirements. As shown in Figure 7.6 and Figure 7.7, below, a greater proportion of the new capacity built under conditions of low natural gas prices is made up of combustion turbines (“CT”), which begin coming on line as early as 2023. Under the HPNG scenario, combustion turbines are not built until 2029.

The two lowest cost technologies for new generation are natural gas-fired combined cycle units (“CCNG”) and combustion turbine units (“CT”). CTs have a lower per-MW installed capacity cost than CCNGs but a higher heat rate, that is, the CTs are less efficient and therefore are more expensive to run at any given natural gas price. The modeling results indicate that in most circumstances, CCNGs are more economic than CTs and hence tend to be the selected technology. However, under the Low Natural Gas Price scenarios, the economics of CTs improve relative to CCNGs since construction costs are unaffected by natural gas prices while operating costs are reduced.

Figure 7.6 HPNG: Cumulative Generation Additions in PJM

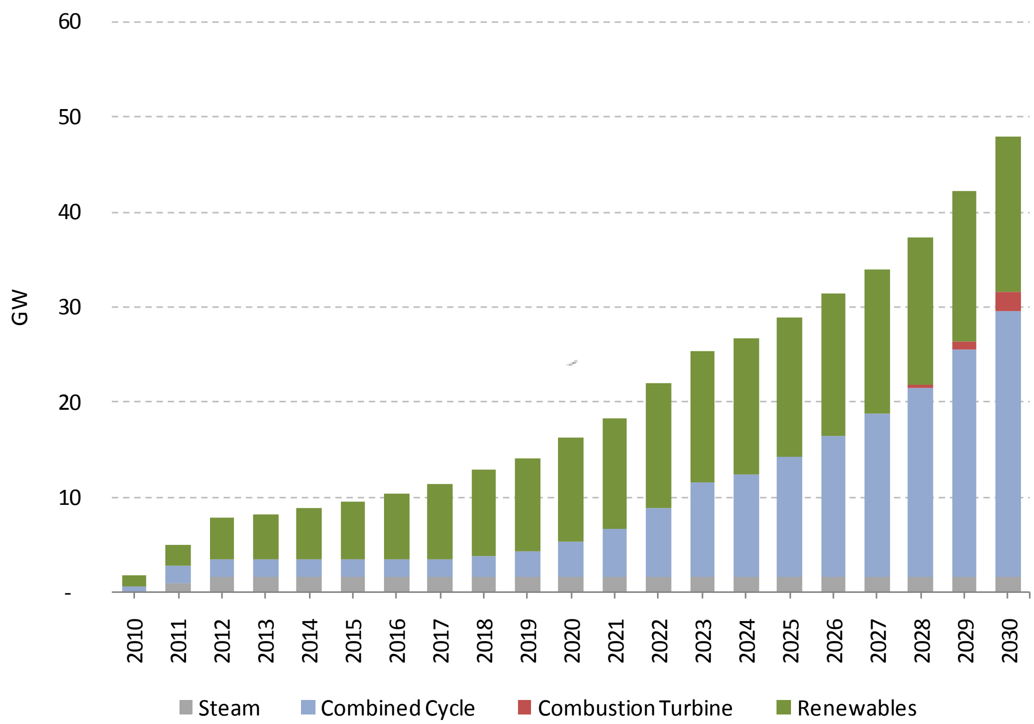


Figure 7.7 LPNG: Cumulative Generation Additions in PJM

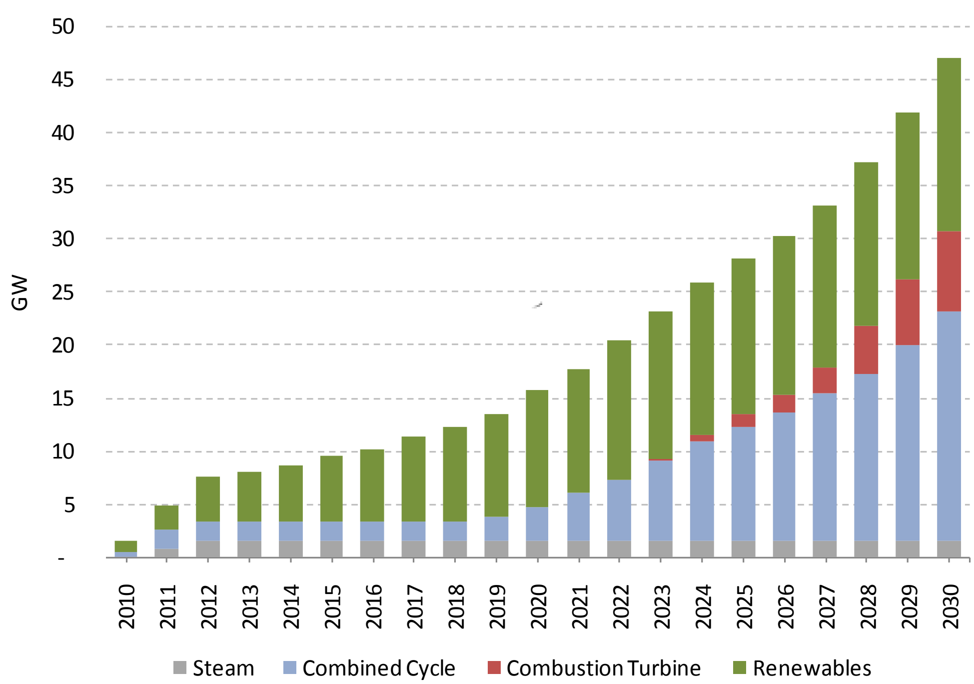


Table 7.1, below, shows the cumulative natural gas capacity additions for the Maryland-relevant zones under the various natural gas price scenarios. Total PJM capacity additions vary only slightly as load growth is the same as in LTER Reference Case. The differences in total PJM builds is mainly due to the composition of the capacity that is added under alternative gas prices, as outlined above (i.e., more CTs are built under lower natural gas prices whereas fewer CTs are built under higher natural gas prices).

Table 7.1
Cumulative Natural Gas Capacity Additions (MW)

Scenario	PJM-SW	PJM-MidE	PJM-APS	PJM Total
RC	2,385	1,908	3,816	30,101
HPNG	2,385	954	3,816	29,927
LPNG	2,907	2,261	3,816	29,335
HPNG+MSD	2,862	651	4,770	29,360
LPNG+MSD	1,605	1,913	4,770	29,599
MSD	1,431	3,816	4,770	30,145

PJM-APS is the least-cost zone for capacity additions relative to PJM-SW and PJM-MidE and, therefore, the total capacity constructed in PJM-APS is not affected by natural gas prices but only by the addition of the Mt. Storm to Doubs transmission upgrade which increases transfer capacity into the eastern zones. The changes in natural gas capacity additions observed in PJM-SW and PJM-MidE are due to the fact that PJM-SW is a lower-cost zone compared to PJM-MidE and therefore, additional capacity will be constructed first in PJM-SW and exported into PJM-MidE as long as transmission transfer capacity is available. Under the HPNG scenario, PJM-MidE builds as little capacity as possible, relying instead on increased imports from the lower-cost zones. Under the LPNG scenario, costs are more equalized across all zones and, therefore, PJM-SW and PJM-MidE rely less on imports and build more internal capacity.

The Mt. Storm to Doubs gives PJM-SW and PJM-MidE access to more imports from lower-cost PJM-APS. PJM-MidE builds the least amount of internal capacity under the HPNG+MSD scenario, relying instead on imports from the lower-cost zones. The MSD effect is mitigated somewhat by the equalizing influence of lower natural gas prices.

7.4 Fuel Use

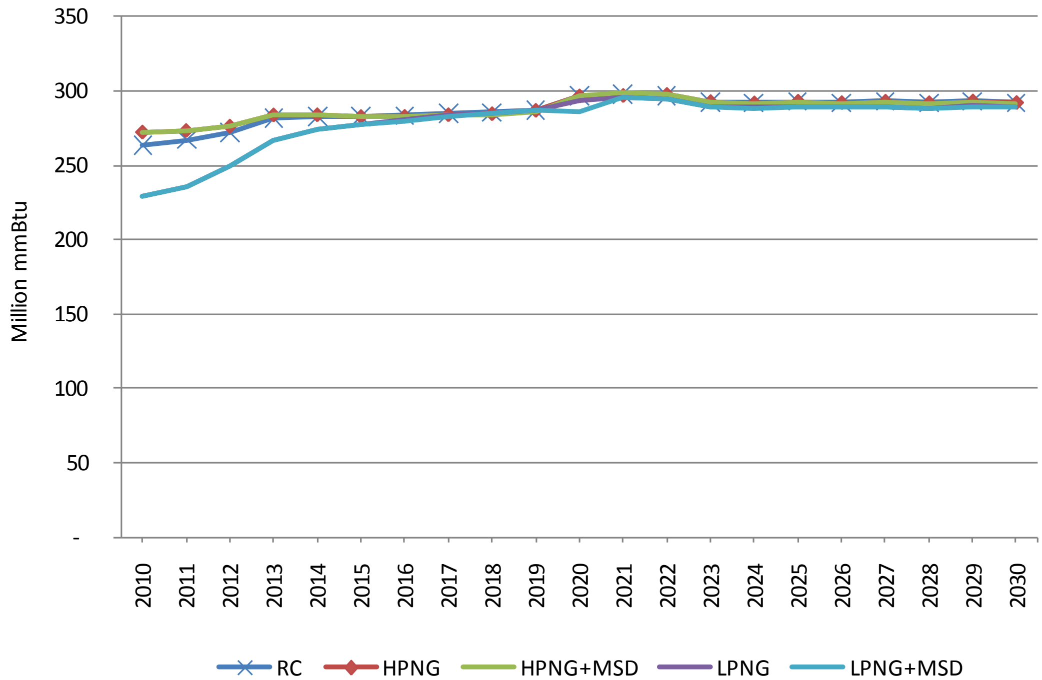
The generation mix in Maryland, shown in Table 7.2 below, changes little among these scenarios compared to the LTER Reference Case, except for LPNG+MSD, when higher levels of power are transported from PJM-APS to PJM-SW. In the LPNG+MSD scenario, the share of natural gas generation in 2030 is 13 percent (compared to 21 percent in the LTER Reference Case); coal is 53 percent (compared to 48 percent in the LTER Reference Case); and nuclear is 26 percent (compared to 23 percent in the LTER Reference Case). The capacity factors for coal-fired plants are higher in the HPNG scenario, while the capacity factor of combined cycle natural gas plants is lower. The reverse is true in the LPNG scenario.

Table 7.2
Maryland Generation Mix (%)

Year	Scenario	Total Generation (GWh)	Gas	Coal	Nuclear	Renewables	Hydro
2010	All	46,389	2	60	32	2	5
2020	RC	53,478	5	58	27	5	4
	HPNG	53,509	4	58	27	5	5
	HPNG+MSD	53,387	4	58	28	5	5
	LPNG	53,668	5	58	27	5	4
	LPNG+MSD	50,533	1	60	29	5	5
2030	RC	64,291	21	48	23	4	4
	HPNG	63,565	20	48	23	4	4
	HPNG+MSD	63,621	20	48	23	4	4
	LPNG	64,910	25	47	23	2	4
	LPNG+MSD	57,581	13	53	26	5	4

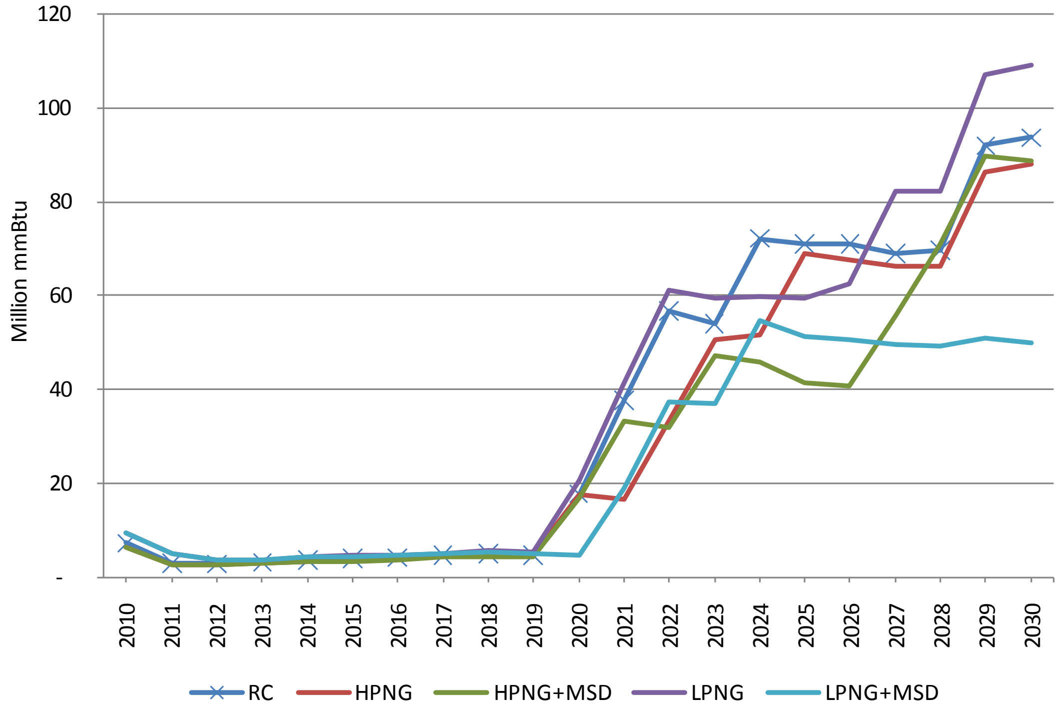
Coal consumption in Maryland is minimally affected by natural gas prices (see Figure 7.8 below). Maryland generators use approximately 2.5 million mmBtu less coal under the lower natural gas price scenarios compared to the LTER Reference Case and the higher natural gas price scenarios.

Figure 7.8 Maryland Coal Use for Electricity Generation



Natural gas consumption is about six percent lower in the HPNG and HPNG+MSD scenarios than the LTER Reference Case, and about 17 percent higher in the LPNG scenario (see Figure 7.9 below). Natural gas consumption is much lower in the LPNG+MSD case, with natural gas consumption reduced by 47 percent due to an increase in power imports into PJM-SW from PJM-APS with the operation of the MSD line.

Figure 7.9 Maryland Natural Gas Use for Electricity Generation



7.5 Energy Prices

Natural gas prices have a significant and direct impact on overall energy prices but are unaffected by the transmission upgrade. In the LTER Reference Case, energy prices increase in real terms in PJM-SW, PJM Mid-E, and PJM-APS until 2020, when new generation begins to come on-line and energy prices stabilize. In the higher natural gas price scenarios, energy prices in real terms continue increasing past 2020 to between \$94 per MWh and \$97 per MWh in PJM-SW, PJM Mid-E, and PJM-APS in 2030, about one-third higher than energy prices in the LTER Reference Case and about twice that of energy prices in the lower natural gas price scenarios. Energy prices in real terms in the lower natural gas price scenarios are about 30 percent lower than energy prices in the LTER Reference Case for PJM-SW, PJM Mid-E and PJM-APS in

2030. Figure 7.10, Figure 7.11, and Figure 7.12, below, show the wholesale energy prices in PJM-SW, PJM-MidE, and PJM-APS, respectively.

Figure 7.10 PJM-SW Real All-Hours Energy Prices

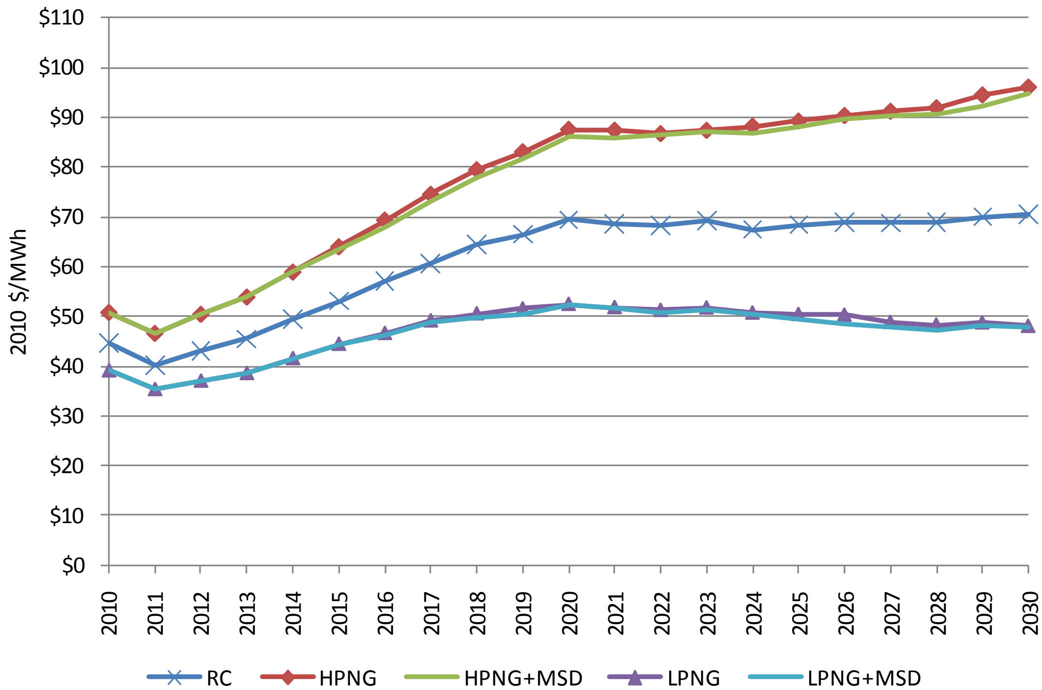


Figure 7.11 PJM-MidE Real All-Hours Energy Prices

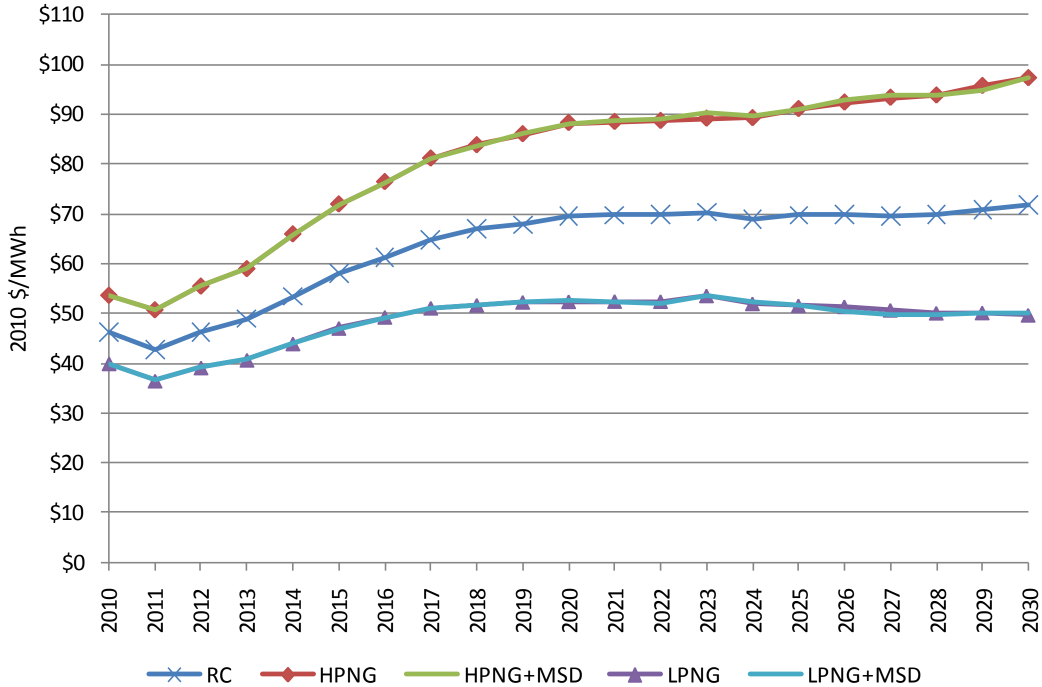
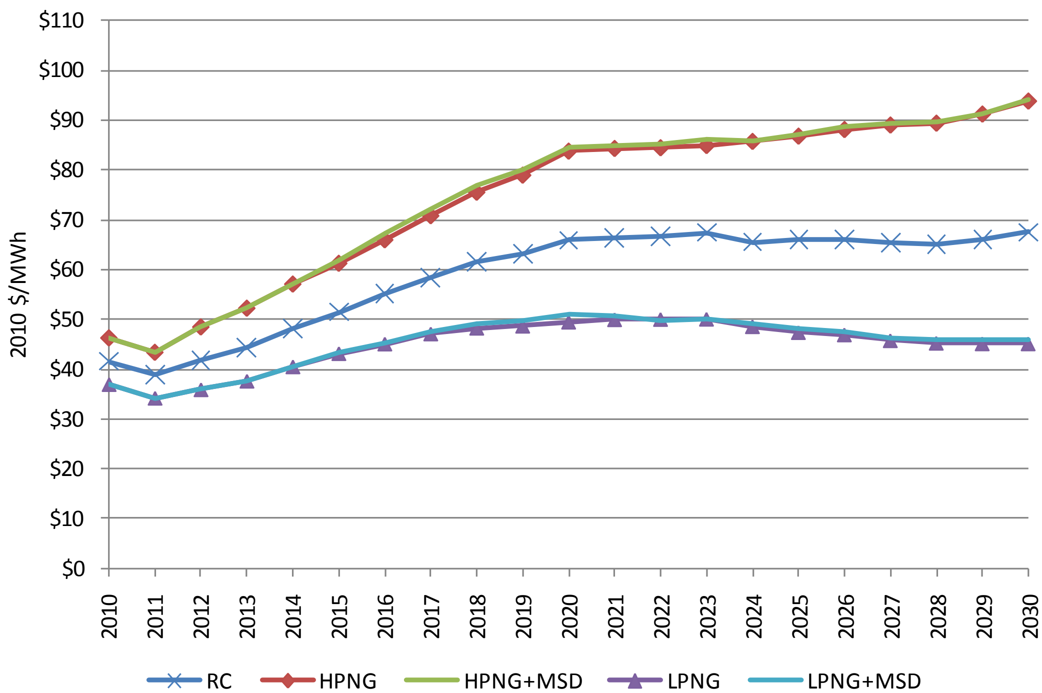


Figure 7.12 PJM-APS Real All-Hours Energy Prices

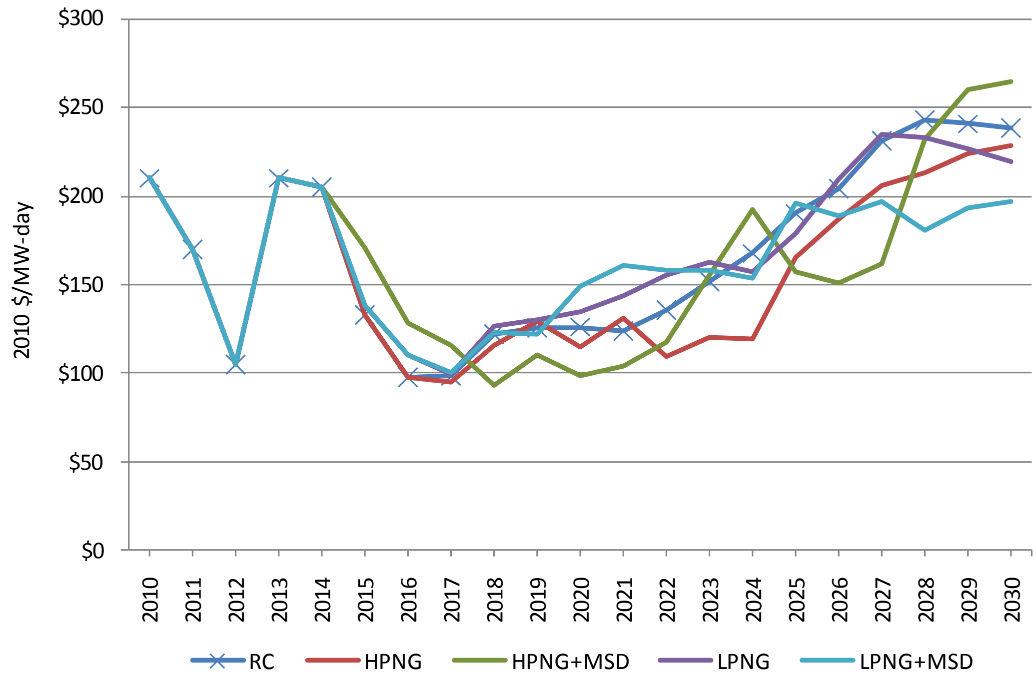


Although the impact of either higher or lower natural gas prices on overall energy prices is clear, Maryland's ability to influence the price of natural gas through measures to encourage additional natural gas supply or to limit demand for natural gas is extremely limited. As noted earlier, natural gas is a national market, with price differentials among various regions in the U.S. attributable to transportation costs. In addition, Maryland's demand for natural gas is a relatively small part of the overall natural gas demand, and available natural gas supplies in Maryland are also not very large. Therefore, Maryland cannot on its own influence natural gas market prices.

7.6 Capacity Prices

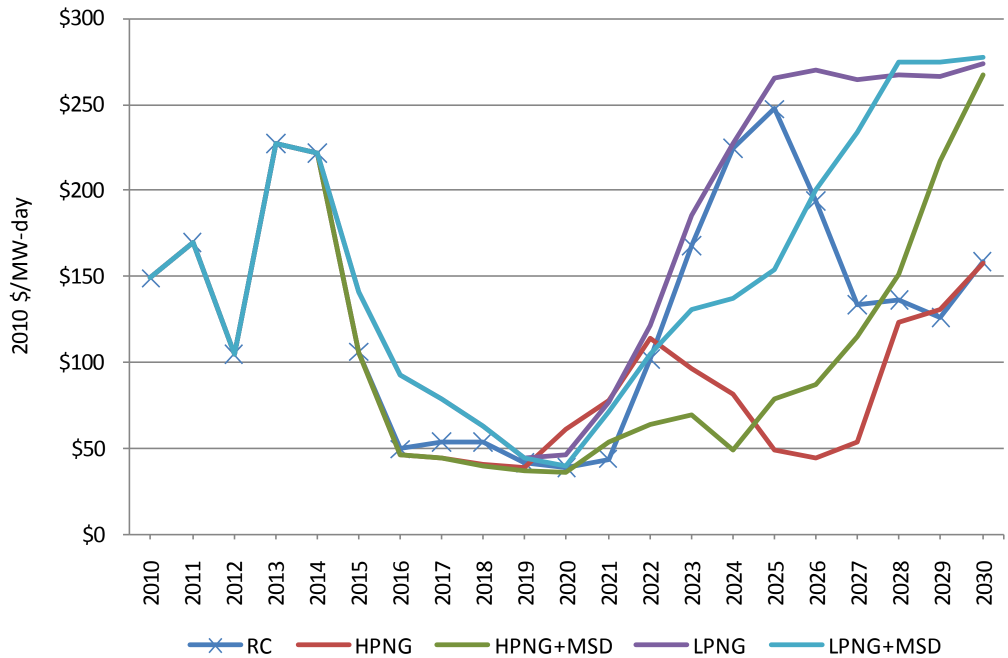
Capacity prices for PJM-SW are shown in Figure 7.13, below. In general, the trend in capacity prices is similar under all of the alternative natural gas price scenarios though capacity prices under the higher natural gas price scenarios are consistently lower than the LTER Reference Case prices. The reason for this is that under conditions of high gas prices, energy prices are high, and new, more efficient generating capacity requires a lower capacity price to be economic. The capacity price under the HPNG+MSD scenario is more volatile due to the changes in the new natural gas capacity build schedule.

Figure 7.13 PJM-SW Capacity Prices



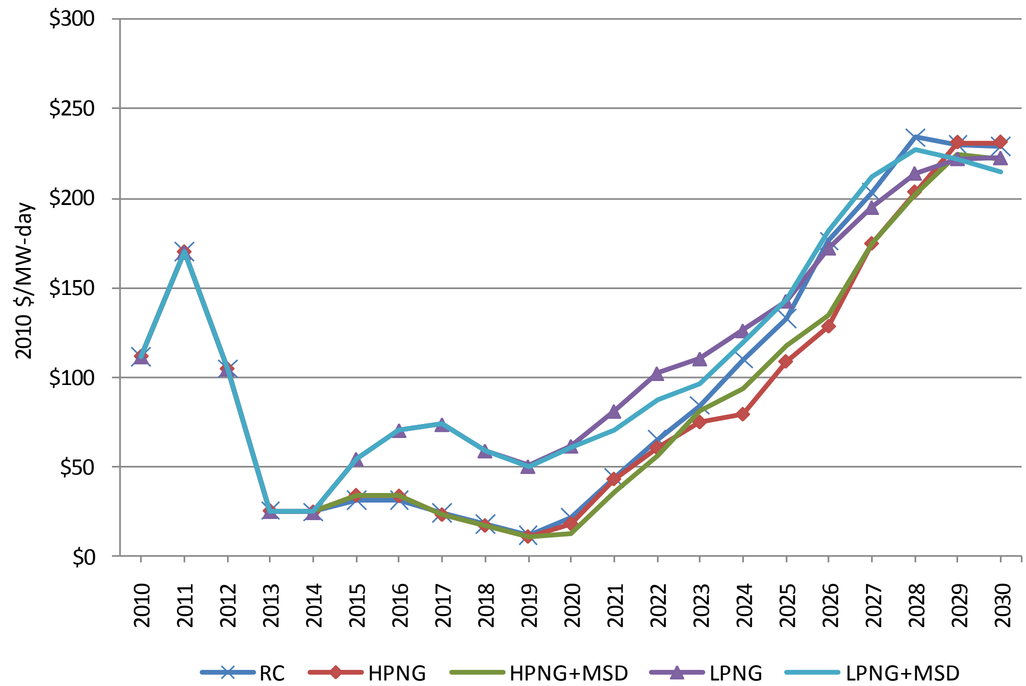
Capacity prices simulated for the PJM-MidE zone are shown in Figure 7.14, below, and exhibit the same volatility that is characteristic of this zone. Capacity prices diverge from 2022 through 2030 because they are highly sensitive to the power plant construction schedule. As was the case for the PJM-SW region, capacity prices for the HPNG scenario are lower than the capacity prices for the LTER Reference Case due to new, more efficient plants being able to operate profitably with lower capacity costs when market energy prices are high. Under the LPNG scenario, capacity prices are higher than under the LTER Reference Case given the low energy prices that result from low gas prices, and the need for higher capacity prices to allow new plants to cover costs.

Figure 7.14 PJM-MidE Capacity Prices



Capacity prices for the PJM-APS zone are shown in Figure 7.15 below. The same basic relationships as discussed for the PJM-SW and PJM-MidE zones with respect to the high and low gas price scenarios relative to the LTER Reference Case are evident for capacity prices in PJM-APS, although they are less pronounced due to a more consistent schedule of plant build-outs. In PJM-APS, capacity prices are more stable than those simulated for PJM-MidE, and tend to converge towards the end of the study period as plant build-out stabilizes.

Figure 7.15 PJM-APS Capacity Prices



7.7 Emissions

Under the lower natural gas price scenarios, SO_2 emissions from plants subject to the Maryland Healthy Air Act ("HAA") are consistently lower than in the LTER Reference Case mainly due to the slight decrease in coal use, as the plants run at reduced capacity factors (see Figure 7.16 below). Under LPNG and LPNG+MSD, Maryland SO_2 emissions are approximately 1,500 tons lower in 2030 compared to the LTER Reference Case. The same impacts are observed for Maryland HAA NO_x emissions thought the differential between the lower natural gas price scenarios and the LTER Reference Case is only about 200 tons in 2030 (see Figure 7.17).

Figure 7.16 SO$_2$ Emissions from Coal Plants Subject to HAA

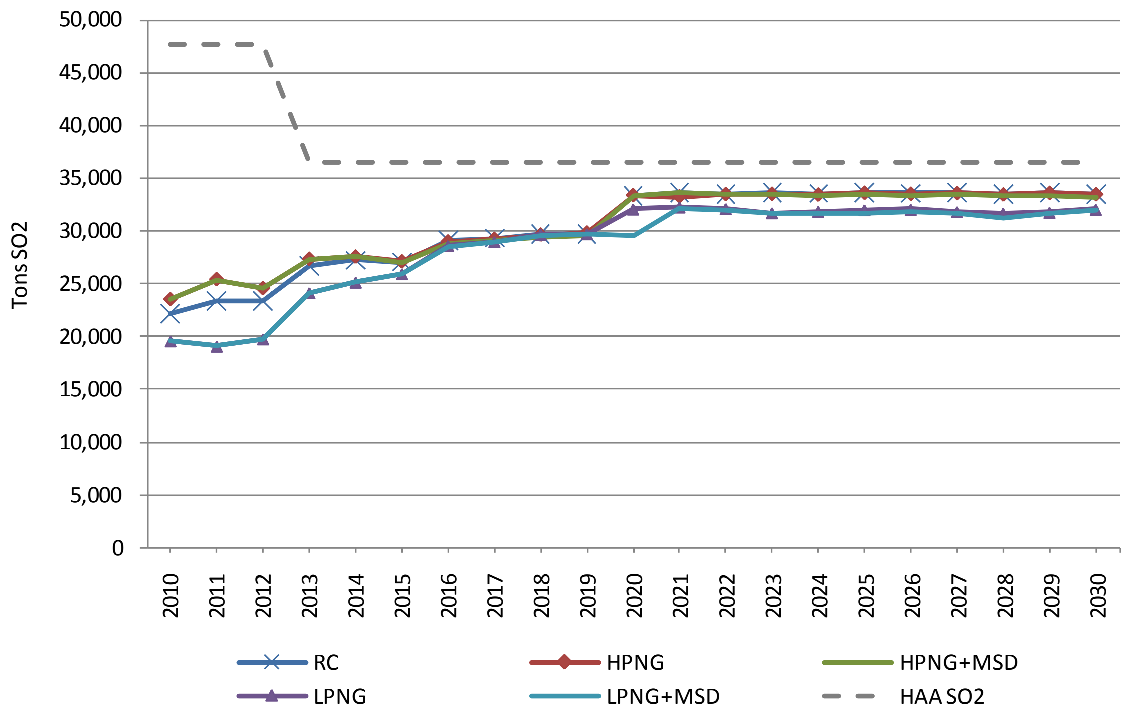
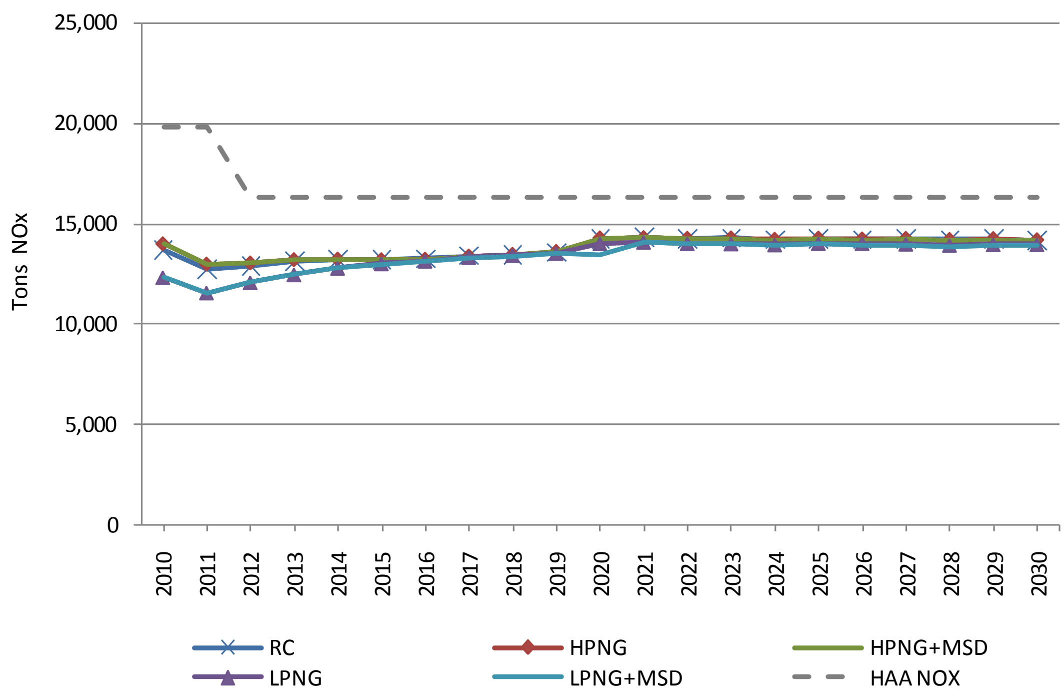
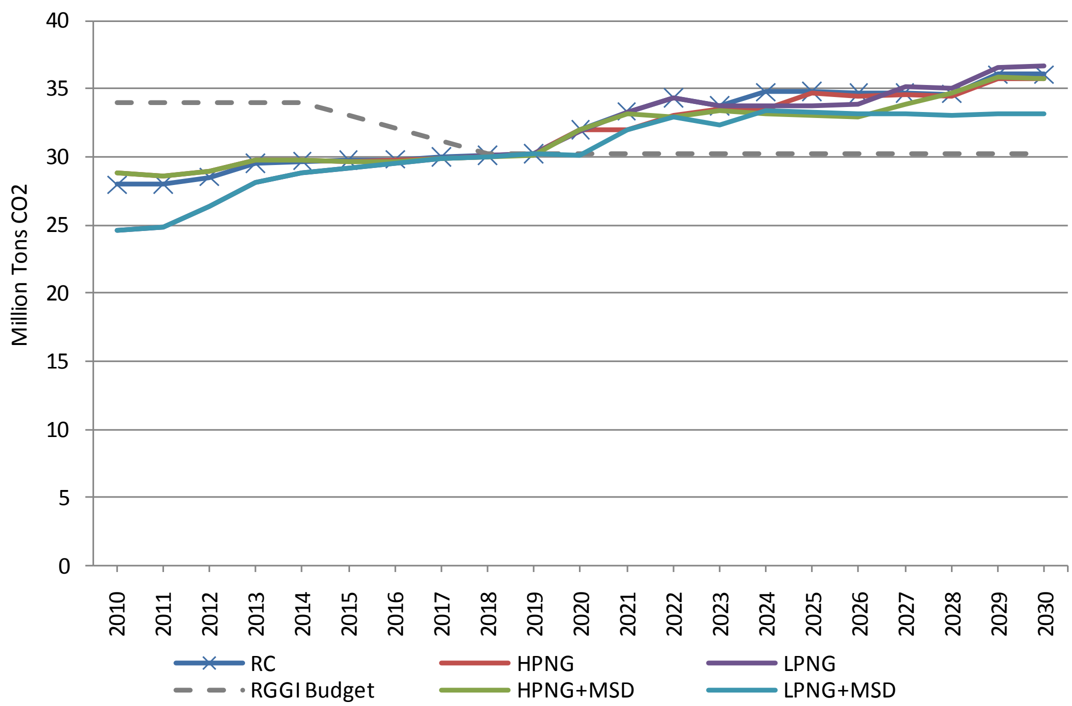


Figure 7.17 NO$_x$ Emissions from Coal Plants Subject to HAA



Total CO_2 emissions in Maryland are very similar to the LTER Reference Case for all the alternative natural gas price scenarios except under the LPNG+MSD scenario. The lower natural gas prices coupled with the increased imports available through the Mt. Storm to Doubs transmission upgrade significantly reduce the new natural gas capacity builds needed in PJM-SW (see Table 7.1, on page 7-8) and, therefore, reduce overall in-State CO_2 emissions. All of the scenarios exceed Maryland's Regional Greenhouse Gas Initiative ("RGGI") budget for CO_2 emissions after 2019, when new natural gas capacity starts to be built.

Figure 7.18 Maryland CO_2 Emissions



7.8 Results

The modeling analysis presented in this chapter provides the following findings:

- The HPNG scenario assumptions do not affect the construction of new gas-fired power plants in PJM-SW or PJM-APS relative to the LTER Reference Case. New power plant construction in PJM-MidE, however, declines by approximately 1,000 MW over the 30-year study period relative to the LTER Reference Case.
- New power plant construction under the LPNG scenario increases by approximately 500 MW in PJM-SW and 400 MW in PJM-MidE relative to the LTER Reference Case over the 30-year study period.
- Construction of new power plants in PJM under the LPNG scenario shows a greater proportion of combustion turbines than is the case under the HPNG scenario.
- There is no significant difference in net energy imports into PJM-SW, PJM-APS, or PJM-MidE based on the alternative gas price assumptions relative to the LTER Reference Case.
- Natural gas prices have a substantial impact on market energy prices. By the year 2030, energy prices under the HPNG scenario – in all three zones that include a Maryland portion – are over $20 per MWh above the LTER Reference Case prices. Under the LPNG scenario, prices in all three zones are more than $20 per MWh below the LTER Reference Case prices.
- Under the HPNG scenario capacity prices in PJM-SW are consistently below the LTER Reference Case capacity prices after 2019. The LPNG scenario does not display any sustained difference in capacity prices relative to the LTER Reference Case.
- In PJM-MidE capacity prices under the HPNG scenario are generally lower than the LTER Reference Case capacity after 2023. Under the LPNG assumptions however, capacity prices are significantly higher than the LTER Reference Case capacity prices after that same year.

- In PJM-APS the capacity prices under the HPNG scenario are consistently lower than those for the LTER Reference Case. There are no significant differences between the capacity prices for the LPNG scenario compared to those for the LTER Reference Case. Capacity prices for all scenarios converge in 2030.
- Emissions of CO_2 in Maryland under all gas price scenarios generally track CO_2 emissions shown for the LTER Reference Case.

8. HIGH AND LOW LOAD ALTERNATIVE SCENARIOS

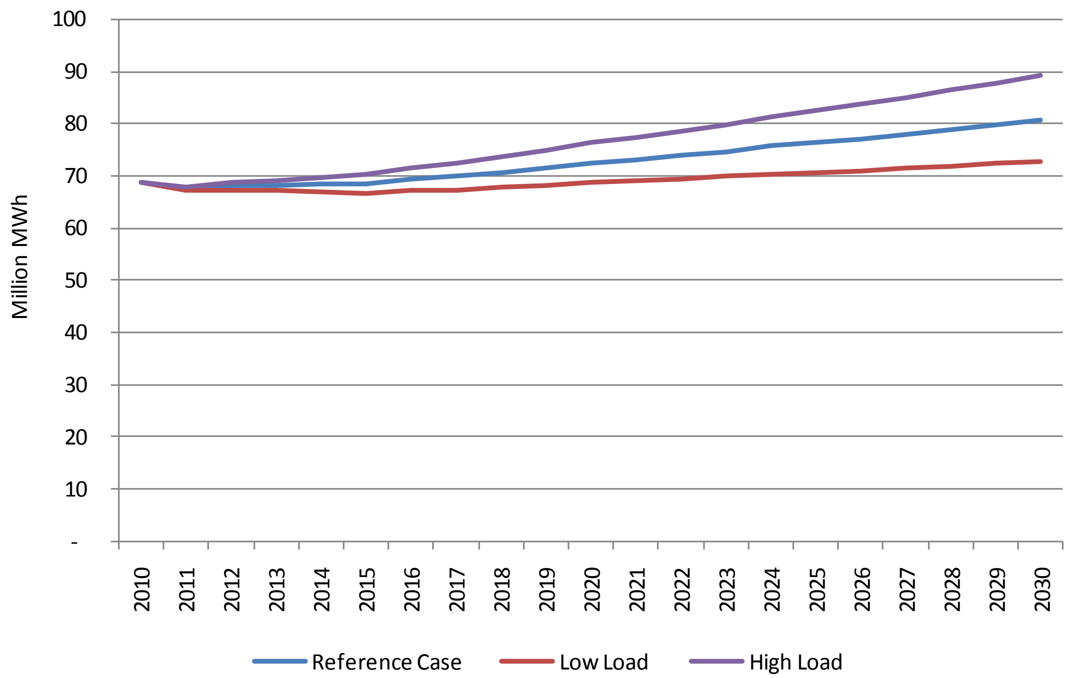
8.1 Introduction

The high and low load alternative scenarios address the estimated impacts of load growth at rates different from those represented in the LTER Reference Case. The high and low load scenarios were run on the LTER Reference Case assumptions and two alternative cases: Low Load ("LL") and High Load ("HL") with the Mt. Storm to Doubs transmission line ("LL+MSD" and "HL+MSD"); and LL and HL with Calvert Cliffs 3, national carbon legislation, the Mt. Storm to Doubs line, and the Mid-Atlantic Power Pathway ("MAPP") transmission line ("LL/CC3/NCO2/MSD/MAPP" and "HL/CC3/NCO2/MSD/MAPP").

The alternative load scenarios assume that all of the Eastern Interconnection, including all of PJM, experiences a different load growth path than that assumed for the LTER Reference Case. The LTER Reference Case load assumptions were altered to incorporate lower and higher load growth rates. Figure 8.1, below, shows the LTER Reference Case load as compared to the high and low loads for the PJM-SW zone. In the Low Load scenario, loads in all PJM zones are approximately 10 percent lower than in the LTER Reference Case by 2030. In the High Load scenario, loads in all PJM zones are approximately 10 percent higher than the LTER Reference Case.

The high load growth scenarios were developed by increasing the growth rate in load used for the LTER Reference Case by 0.5 percentage points per year. Analogously, the low load growth scenarios were developed by reducing the growth rate in load used for the LTER Reference Case by 0.5 percentage points per year. These changes allow for meaningful and sustained deviations in load relative to the LTER Reference Case but should not be interpreted as either upper or lower bounds to load growth. Load could increase more rapidly than represented by the high load cases or less rapidly than represented by the low load cases. The high and low load cases, however, represent plausible alternatives to the LTER Reference Case loads while allowing significant deviation from the LTER Reference Case loads.

Figure 8.1 PJM-SW Loads



8.2 Capacity Additions and Retirements

For all load scenarios, planned capacity additions and age-based plant retirements are identical to those for the LTER Reference Case since these are incorporated by assumption into the model. While total renewable energy builds in PJM are affected by load growth, the renewable energy builds in Maryland are not affected, as Maryland sources the major portion of RPS requirements from out-of-state resources under all but the High Renewables scenarios.

Economic retirements are affected by changes in load. Table 8.1, below, outlines the economic retirements for the LTER Reference Case and the load cases, and compares them to the LTER Reference Case modified to include the Mt. Storm to Doubs line ("MSD") and the LTER Reference Case that includes Calvert Cliffs Unit 3, national carbon legislation, the Mt. Storm to Doubs line, and the MAPP transmission line ("CC3/NCO2/MSD/MAPP"). Under the MSD scenario, economic retirements were identical to the LTER Reference Case, and, as shown in Table 8.1, the assumptions for low and high load growth alone and with MSD have only a minor impact on economic retirements. However, load growth changes under a carbon legislation assumption have a significant effect on economic retirements. Under low load growth assumptions, an additional 1,296 MW of capacity retires as compared to the CC3/NCO2/MSD/MAPP scenario with LTER Reference Case load, and under high load growth, there are 865 MW fewer retirements. Under all high load growth scenarios, economic retirements occur less compared to the LTER Reference Case, as it becomes more economic for plants that would otherwise retire to stay in-service due to the increased electricity demand.

Table 8.1
PJM Economic Retirements

Scenario	Plant Retirements (MW)
RC	315
MSD	315
LL and LL+MSD	300
HL and HL+MSD	194
CC3/NCO2/MSD/MAPP	1,098
LL/CC3/NCO2/MSD/MAPP	2,394
HL/CC3/NCO2/MSD/MAPP	233

The total MW of natural gas-fired capacity added in PJM-SW is strongly affected by the changes in load (see Table 8.2, below). In the LTER Reference Case, PJM-SW builds 2,385 MW of natural gas capacity, and in all of the low load scenarios, this capacity is reduced to 1,908 MW. The addition of MSD and national carbon legislation does not affect builds of natural gas plants in PJM-SW but does affect builds in PJM-MidE. At lower load levels than assumed for the LTER Reference Case, loads stay below the threshold in PJM-MidE that would require adding generating capacity. Under a national carbon legislation assumption, PJM-MidE needs to build a small amount of gas-fired capacity as coal-fired generation is displaced. PJM as a whole needs only 8,109 MW of incremental capacity to meet load requirements in LL and LL+MSD, as opposed to the 30,101 MW built in the LTER Reference Case.

Under the HL scenario, PJM-SW needs to build over 1,400 MW of additional natural gas capacity to account for the increased demand, and PJM-MidE needs over 3,600 MW of additional capacity compared to the LTER Reference Case. The Mt. Storm to Doubs transmission line reduces the need for capacity builds only slightly and some additional capacity is required in the national carbon legislation case due to a reduction in coal generation.

Table 8.2
Cumulative Natural Gas Capacity Additions Through 2030 (MW)

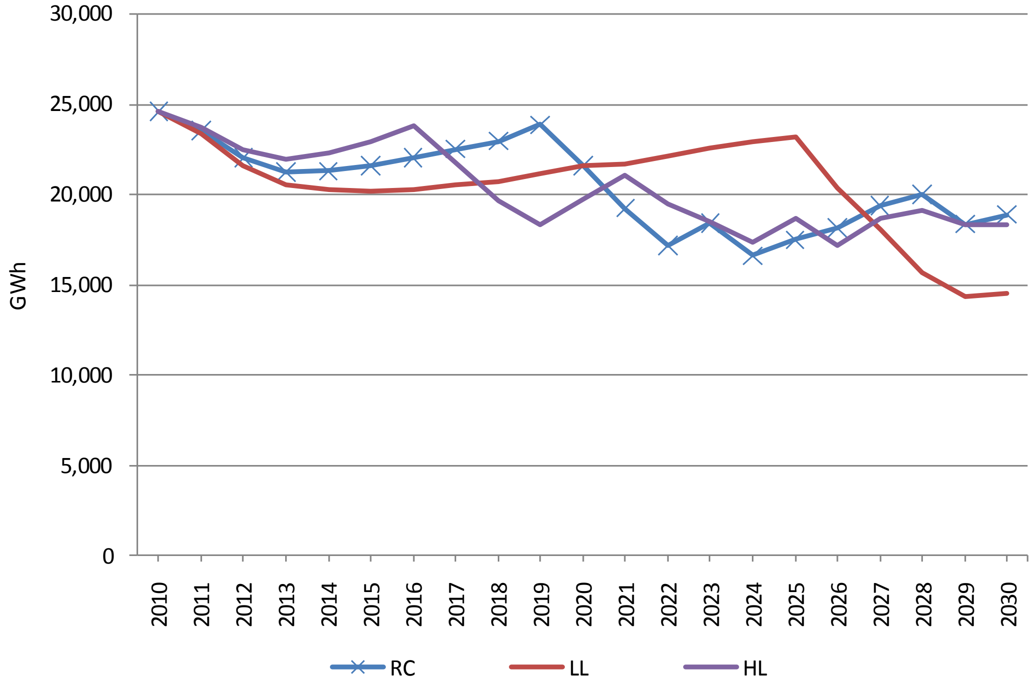
Scenario	PJM-SW	PJM-MidE	PJM-APS	PJM Total
RC	2,385	1,908	3,816	30,101
LL and LL+MSD	1,908	0	954	8,109 and 8,586
LL/CC3/NCO2/MSD/MAPP	1,908	954	1,431	14,966
HL	3,816	5,515	5,724	51,839
HL+MSD	3,081	5,471	6,375	52,932
HL/CC3/NCO2/MSD/MAPP	4,239	5,863	5,724	57,622

The changes in load growth also affect the timing of the capacity builds. In the LTER Reference Case, new capacity is added to PJM-SW in 2019, whereas the low load assumption delays the need for new capacity to 2025. The Mt. Storm to Doubs transmission line delays the capacity build by one more year and natural gas capacity additions are not seen until 2026. Under all of the high load scenarios, capacity additions begin earlier in 2016 due to the increased load growth.

8.3 Net Imports

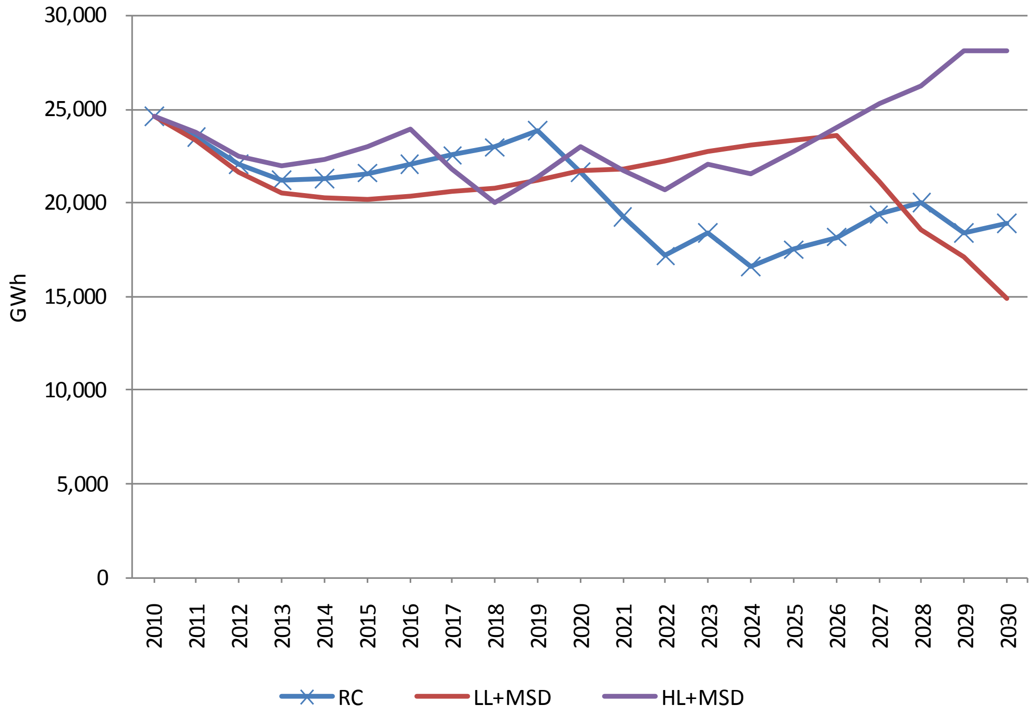
As with the LTER Reference Case, net imports for PJM-SW generally decrease throughout the study period as new generation is built in the eastern zones. Figure 8.2, below, shows the net imports into PJM-SW under the LTER Reference Case and the high and low load scenarios. Net imports under the RC and HL assumptions are relatively stable, with any remaining variability that does exist resulting from the timing of the capacity builds. Under the Low Load scenario, net imports are higher than the LTER Reference Case for several years, until new capacity starts to come on-line and imports are reduced to below both the LTER Reference Case and the High Load scenario. Note, however, that the differences in net imports for PJM-SW are small.

Figure 8.2 PJM-SW Net Imports



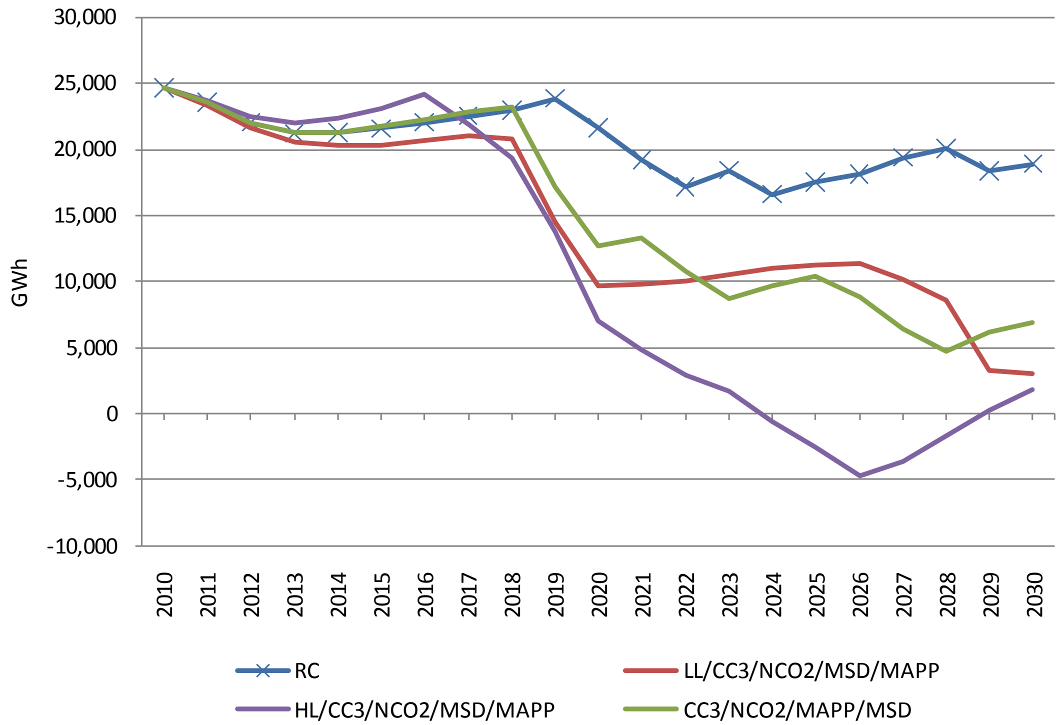
The High Load plus Mt. Storm to Doubs scenario is the only scenario that shows a generally increasing trend for net imports into PJM-SW relative to the LTER Reference Case results (see Figure 8.3 below). Under the HL+MSD assumptions, net imports decrease slightly between 2016 and 2023 but begin to increase steadily in 2024 to reach a total of 28,157 GWh in 2030. The PJM-SW zone sources as much energy as possible from the western PJM zones utilizing the increased transmission capacity available from the Mt. Storm to Doubs line.

Figure 8.3 PJM-SW Net Imports for Low & High Load and MSD



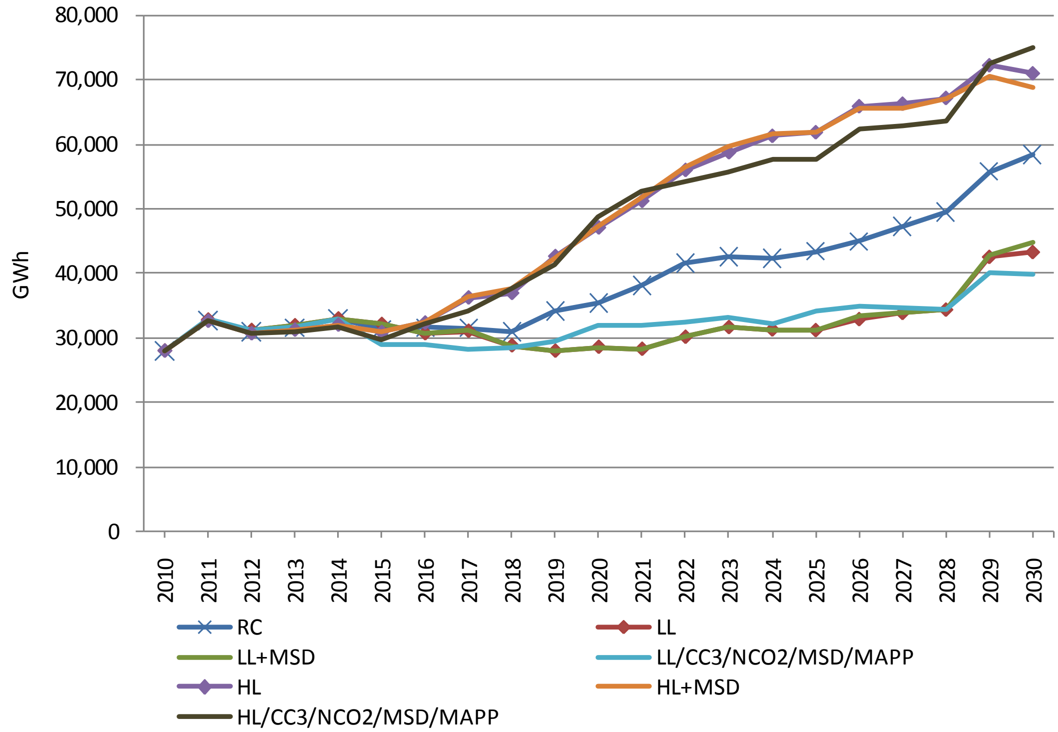
Under the carbon legislation scenarios with both high and low load growth, imports are significantly reduced relative to the LTER Reference Case as new, cleaner generation is built to replace coal-fired generation. In the HL/CC3/NCO2/MSD/MAPP scenario, net imports drop below zero and PJM-SW becomes an energy exporter to PJM-MidE for the years 2024 through 2029 (see Figure 8.4 below). The net imports for PJM-MidE under this scenario reach a high of 75,111 GWh by 2030 as compared to the 58,513 GWh of net imports in 2030 in the LTER Reference Case.

Figure 8.4 PJM-SW Net Imports Under Carbon Legislation Scenarios



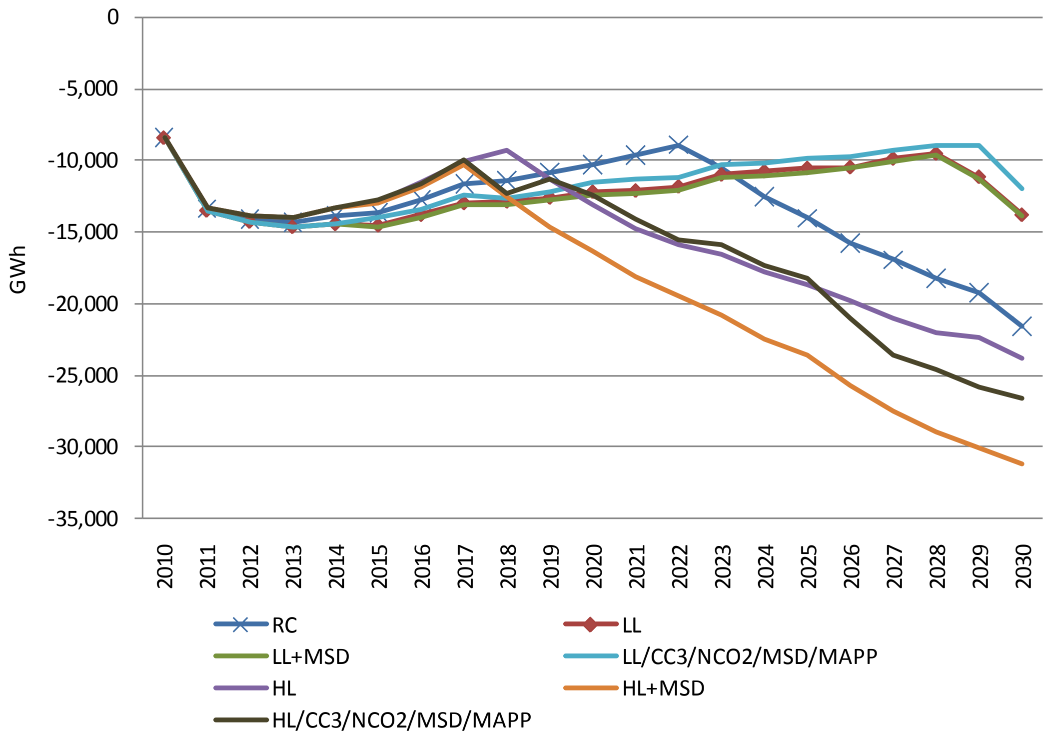
Net imports in PJM-MidE are strongly affected by changes in load but only marginally by infrastructure and carbon prices. Figure 8.5, below, shows net imports for PJM-MidE under all of the load scenarios. PJM-MidE is a higher-priced zone and economics favor imports from areas to the west over construction of new generation. Net imports for PJM-MidE are considerably lower under all three low load scenarios compared to the LTER Reference Case, but are very similar to each other. Net imports for PJM-MidE are considerably higher under the high load scenarios relative to the LTER Reference Case, but there is little difference in imports among the high load scenarios.

Figure 8.5 PJM-MidE Net Imports for All Load Scenarios



For PJM-APS, which is a net exporter of energy under the LTER Reference Case and all of the alternative load scenarios, exports decrease under all the low load scenarios compared to the LTER Reference Case, and increase under the high load scenarios relative to the LTER Reference Case. Figure 8.6, below, shows the net imports for PJM-APS under all the load scenarios. In the high load situation, exports are highest in the scenario with MSD due to the increased ability to export energy into PJM-SW. This effect is mitigated by the addition of a carbon price, as PJM-APS must meet more of its own internal load growth with the added new capacity due to capacity losses from retrofit de-rates.

Figure 8.6 PJM-APS Net Imports for All Load Scenarios

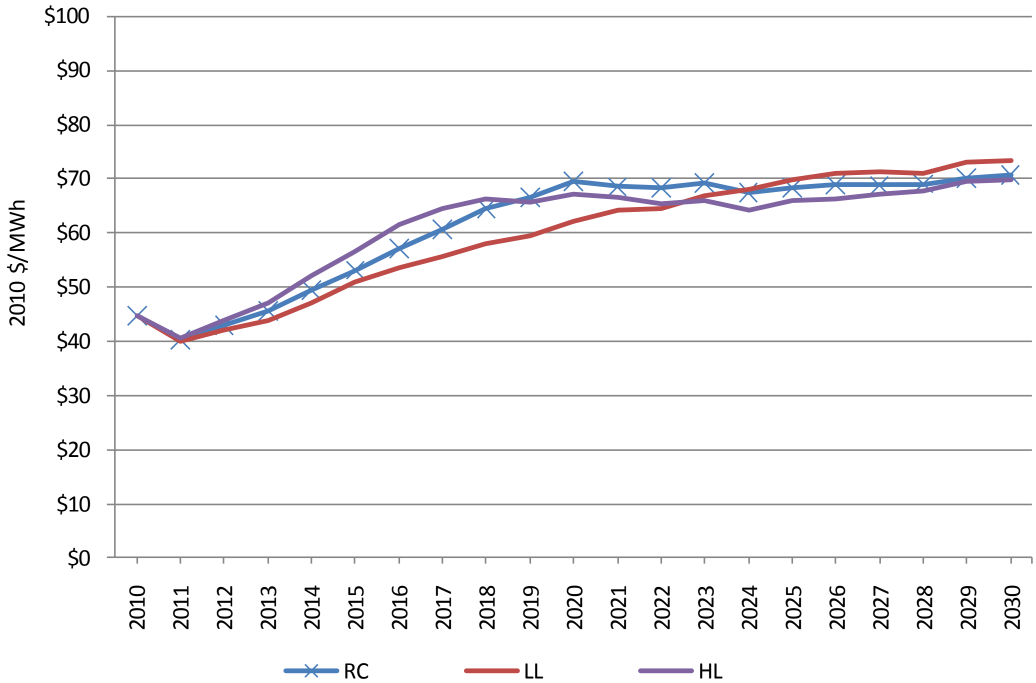


8.4 Energy Prices

In the mid-term, energy prices are significantly affected by changes in load growth. Figure 10.5 below shows that in real terms, energy prices in PJM-SW rise more quickly in the high load scenario and more slowly in the low load scenario – both relative to the LTER Reference Case. Energy prices stabilize, however, after new generation starts to be built. This is particularly evident in the LTER Reference Case and the HL scenarios.

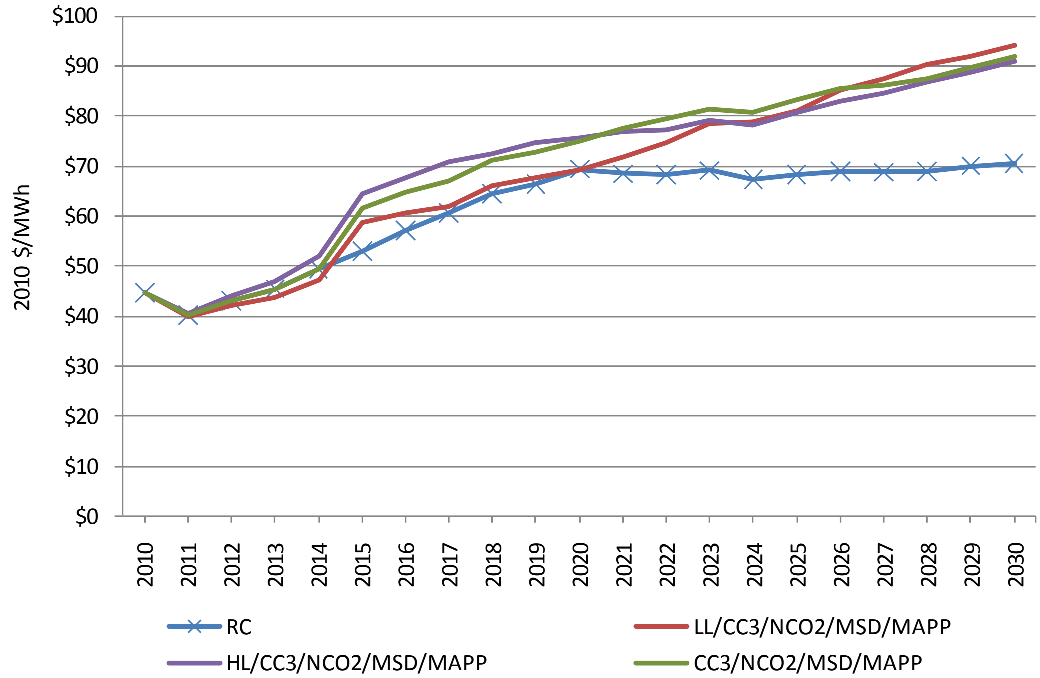
Energy prices for the High Load scenario are below those of the LTER Reference Case starting in 2019 and energy prices under the Low Load scenario are above those in the LTER Reference Case after 2023. The reason for this result is that under conditions of high load growth, more new capacity is built earlier and the new capacity is more efficient than the older capacity, thus resulting in lower energy prices. Over time, as new plants are added under the LTER Reference Case and also under the Low Load scenario, energy prices converge. We see evidence of this price convergence towards the end of the 20-year study period.

Figure 8.7 PJM-SW Real All-Hours Energy Prices for Load Scenarios



Energy prices under the other High Load and Low Load scenarios are only marginally different from High Load and Low Load scenarios built around the LTER Reference Case. The addition of the Mt. Storm to Doubs transmission line has no significant effect on energy prices, and carbon price effects dominate in the national carbon scenarios, with the energy price increasing in the same pattern as observed in all of the other scenarios with national carbon legislation in the High Load and Low Load scenarios that include a carbon price (see Figure 8.8 below). There is a slight energy price increase in the last five years under the LL/CC3/NCO2/MSD/MAPP scenario by 2030 due to the fleet efficiency effects described earlier. In the mid-term, energy prices under LL/CC3/NCO2/MSD/MAPP are below the CC3/NCO2/MSD/MAPP level, but begin to converge post-2023 when new generation starts to be built.

Figure 8.8 PJM-SW Real All-Hours Energy Prices for Load and Carbon Price Scenarios



This same energy price pattern observed for PJM-SW is observed in the PJM-MidE and PJM-APS energy prices (see below in Figure 8.9 and Figure 8.10). The most significant price differentials for the High Load and Low Load scenarios (excluding changes other than load growth) in comparison to the LTER Reference Case are associated with the plant build-out schedule and the resulting impacts that newer plants have on efficiency. Significant and sustained price differentials in PJM-MidE and PJM-APS, however, are not related to load levels but rather to the enactment of national carbon legislation.

Figure 8.9 PJM-MidE Real All-Hours Energy Prics for Load and Carbon Price Scenarios

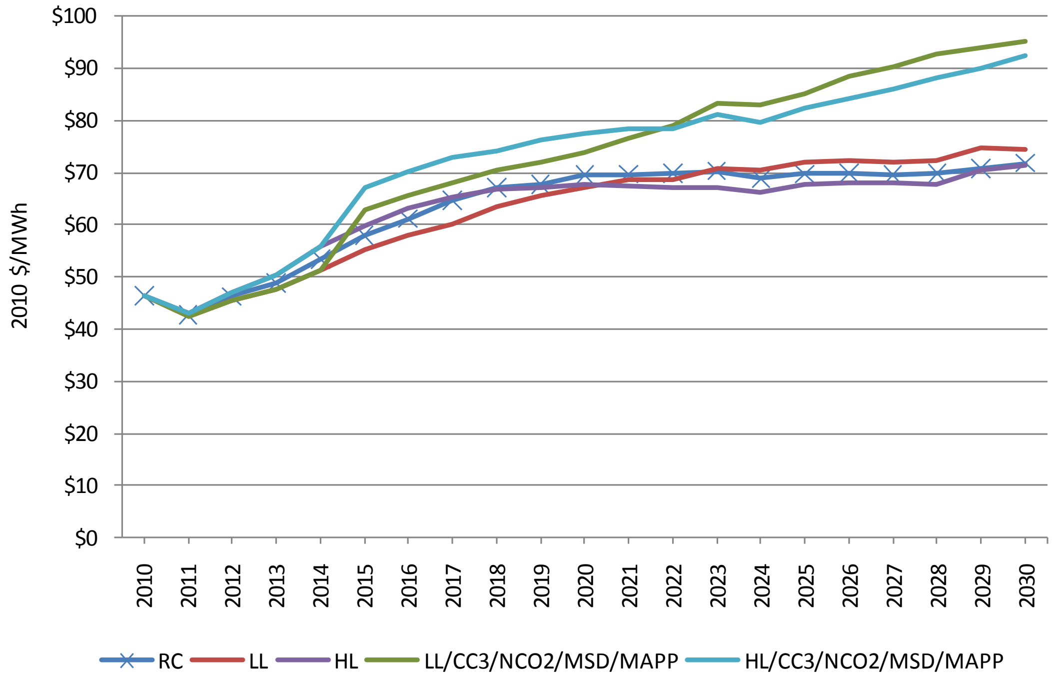
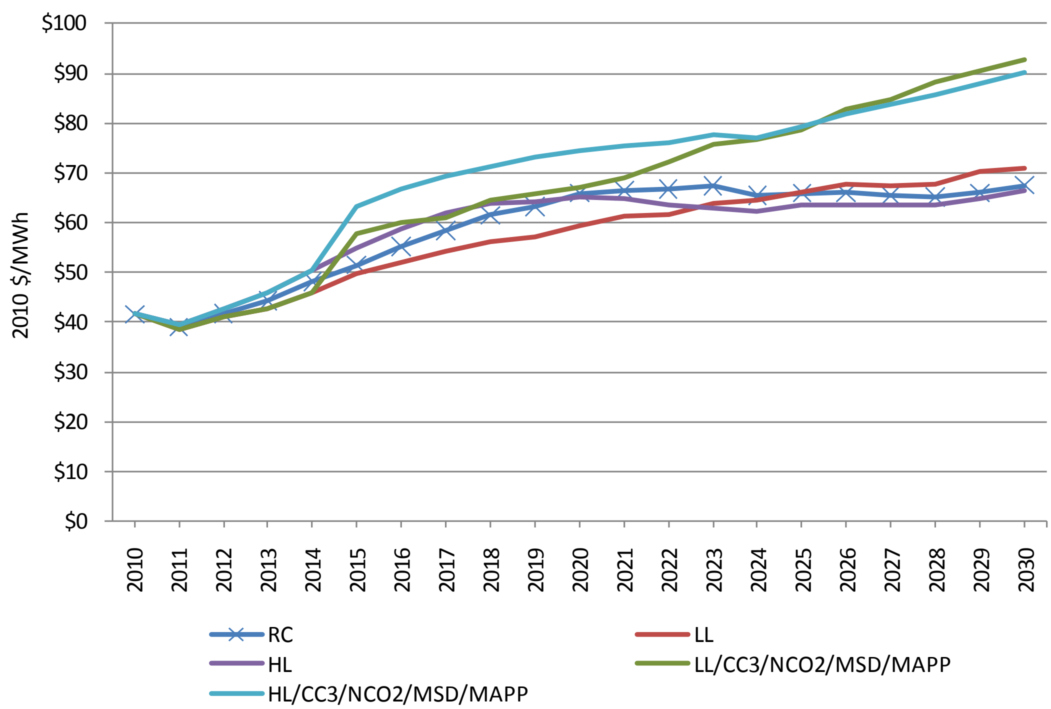


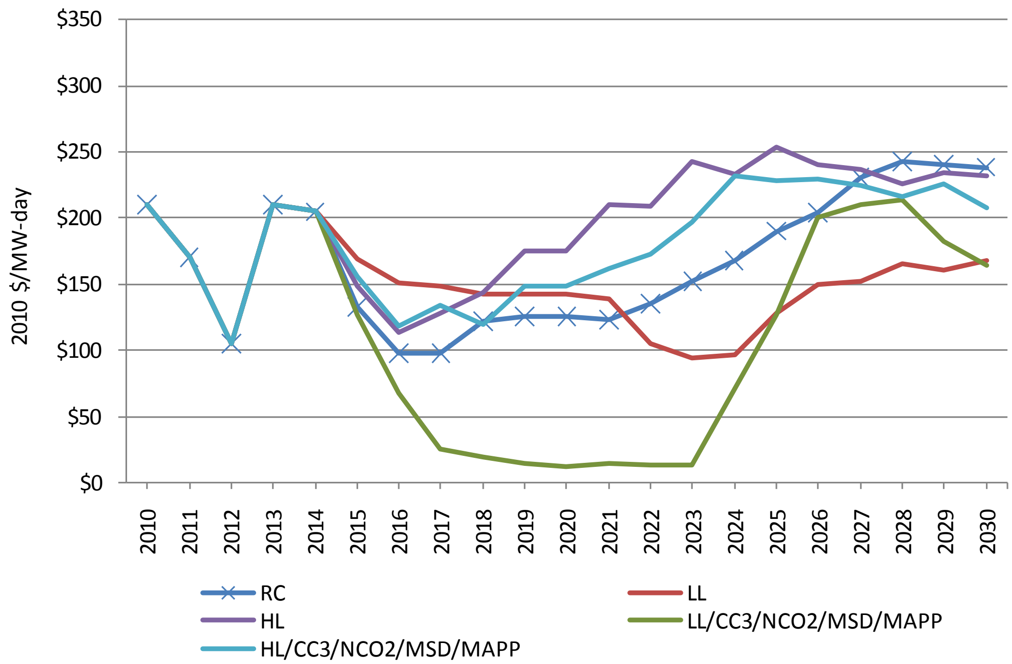
Figure 8.10 PJM-APS Real All-Hours Energy Prices for Load and Carbon Price Scenarios



8.5 Capacity Prices

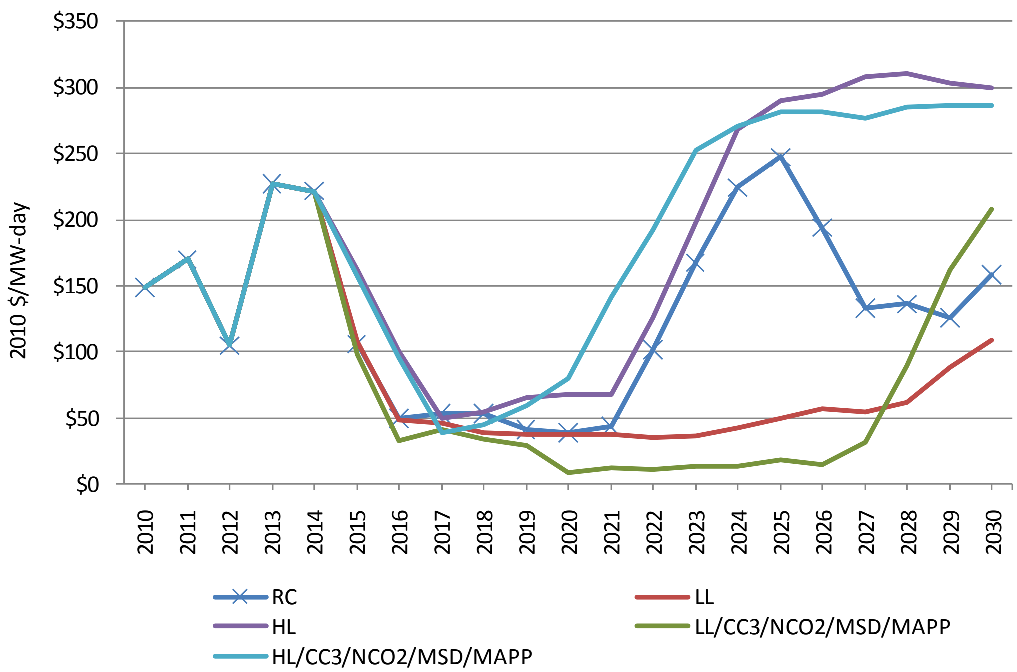
Capacity prices in all three Maryland-relevant zones are low relative to the LTER Reference Case until the model begins to build new natural gas plants under the low load scenarios. The excess capacity situation that exists in the earlier years puts downward pressure on capacity prices in the low load scenarios. The MSD transmission line appears to further reduce capacity prices in PJM-SW, which reflects the availability of imports from PJM-APS.

Figure 8.11 PJM-SW Capacity Prices for Load and Carbon Price Scenarios



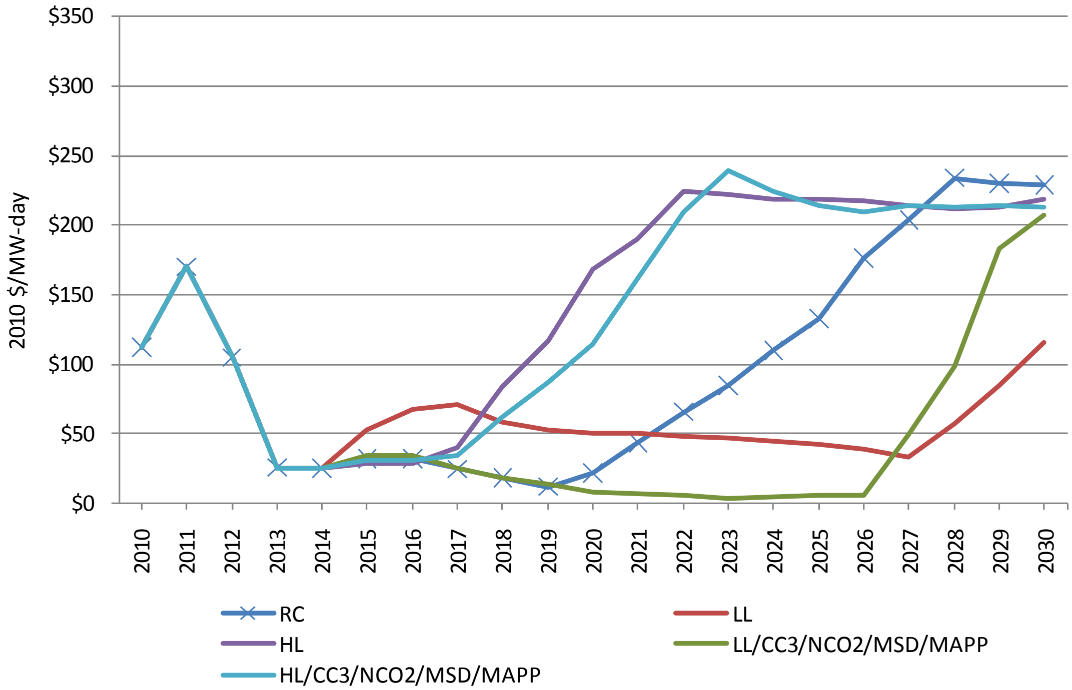
In PJM-SW, capacity prices converge towards the end of the study period (see Figure 8.11 above). While this result is expected, convergence is a slower process in PJM-MidE (see Figure 8.12 below). In PJM-MidE, substantial differences remain in the capacity prices throughout the second half of the study period, which is similar to results obtained for other sets of alternative scenarios presented in the following chapters.

Figure 8.12 PJM-MidE Capacity Prices for Load and Carbon Price Scenarios



In PJM-APS, most of the capacity prices have converged by 2030 (see Figure 8.13 below), although the capacity prices for the LTER Reference Case adjusted for only lower loads remain below the capacity prices for the other load scenarios (and the LTER Reference Case) by about $100 per MW-day.

Figure 8.13 PJM-APS Capacity Prices for Load and Carbon Price Scenarios



8.6 Emissions

For Maryland plants subject to the Healthy Air Act ("HAA"), SO_2 and NO_x emissions in the long-run are relatively unchanged from the LTER Reference Case results and are not significantly affected by the MSD transmission upgrade. In the mid-years however, there are fewer emissions in the low load scenarios, as coal generation operates at a lower capacity factor for a longer period of time (see below in Figure 8.14 and Figure 8.15).

Figure 8.14 Maryland HAA SO_2 Emissions

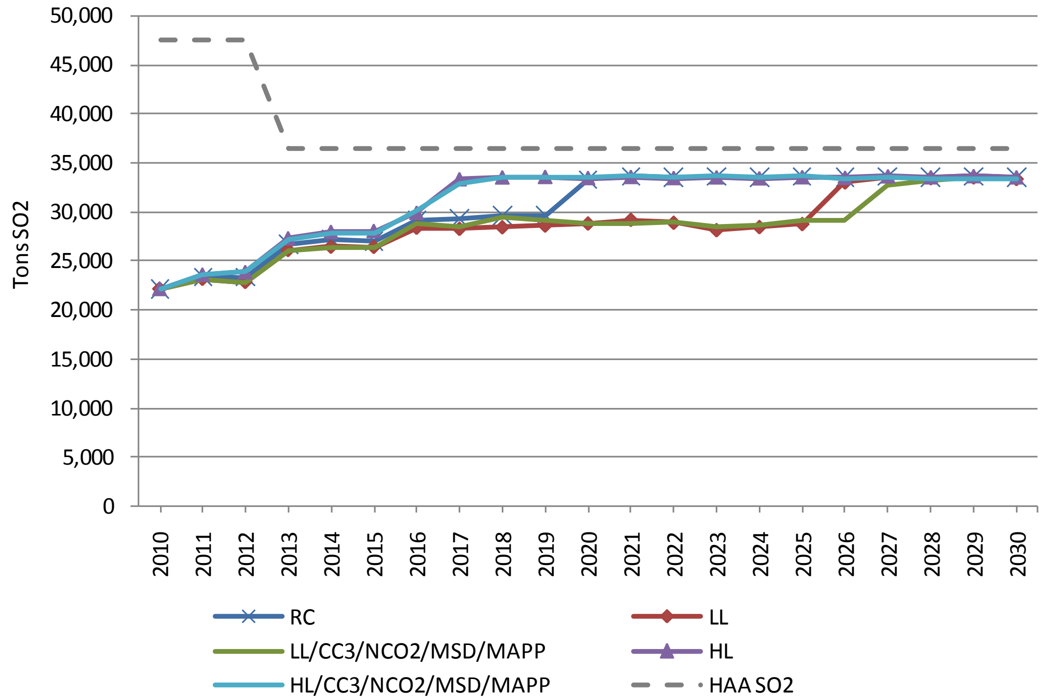


Figure 8.15 Maryland HAA NO_x Emissions

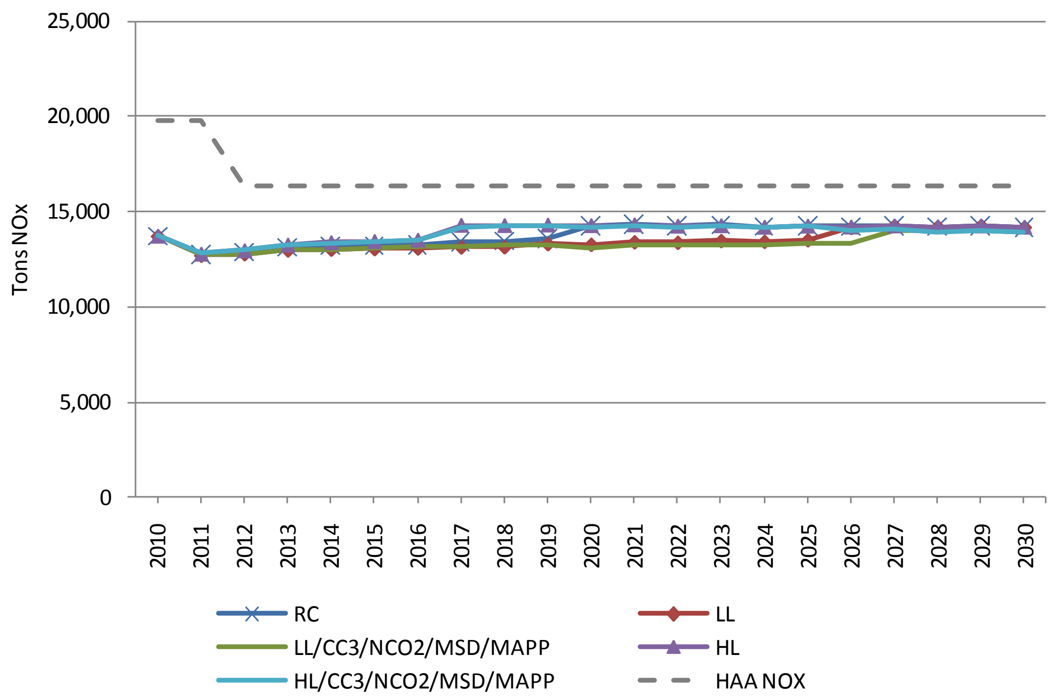


Table 8.3, below, shows the total NO_x emissions for Maryland in 2030. Total NO_x emissions are lower in the low load cases, as fewer new natural gas plants are constructed. Total NO_x emissions in HL+MSD are lower relative to the other high load cases, as Maryland imports more energy from PJM-APS instead of building new natural gas capacity.

Table 8.3
Total Maryland NO_x Emissions in 2030 for All Load Scenarios

Scenario	Total NOx Emissions (tons)
RC	17,223
LL	16,882
LL+MSD	16,817
LL/CC3/NCO2MSD/MAPP	16,820
HL	18,147
HL+MSD	17,181
HL/CC3/NCO2/MSD/MAPP	18,545

Maryland in-State CO_2 emissions are also lower in the low load cases due to fewer plants being built. Figure 8.16, below, shows CO_2 emissions for the load scenarios and the load scenarios with MSD. Emissions begin to rise sharply in low load cases as load growth catches up with supply and new natural gas plants begin to come on-line. Under HL+MSD, in-State CO_2 emissions are much lower than under high load alone since more energy is imported from PJM-APS.

Figure 8.16 Maryland CO_2 Emissions for Load and MSD Scenarios

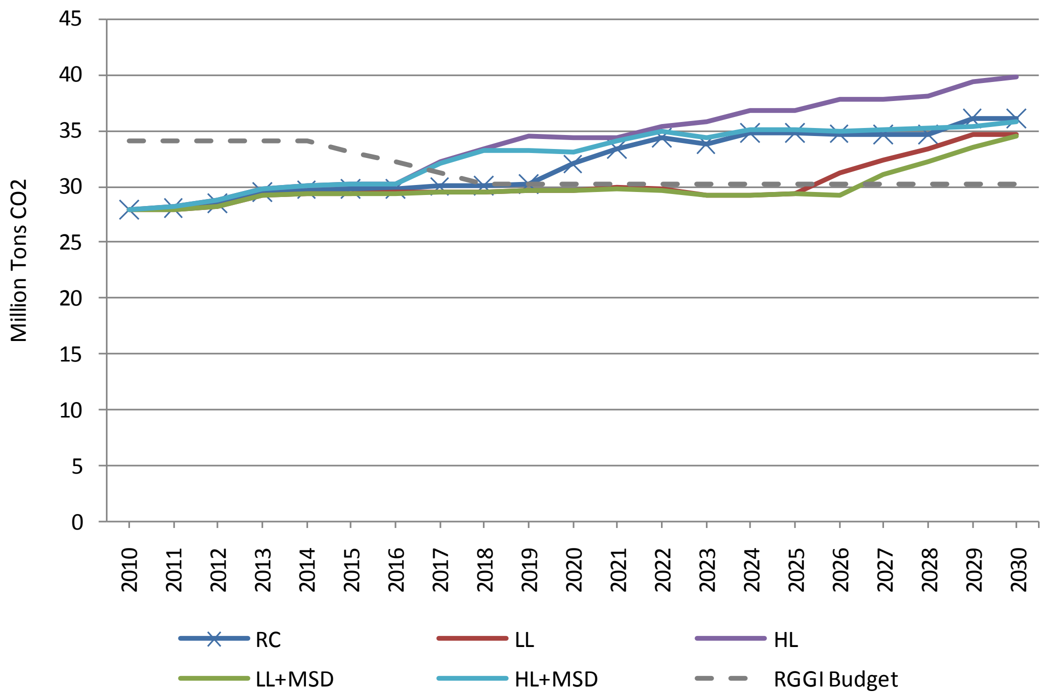


Figure 8.17, below, shows the total Maryland CO_2 emissions for the high and low load scenarios with a carbon price. Total in-State CO_2 emissions begin to decrease after 2025 due to retrofit de-rates and reduced use of coal-fired facilities. The LL and LL+MSD scenarios are below the Maryland Regional Greenhouse Gas Initiative's ("RGGI") CO_2 budget until 2024/2025 when new natural gas generation begins to come on-line. Only the LL/CC3/NCO2/MSD/MAPP scenario has in-State CO_2 emissions that are below the RGGI budget.

Figure 8.17 Total Maryland CO_2 Emissions for Load and NCO2 Scenarios

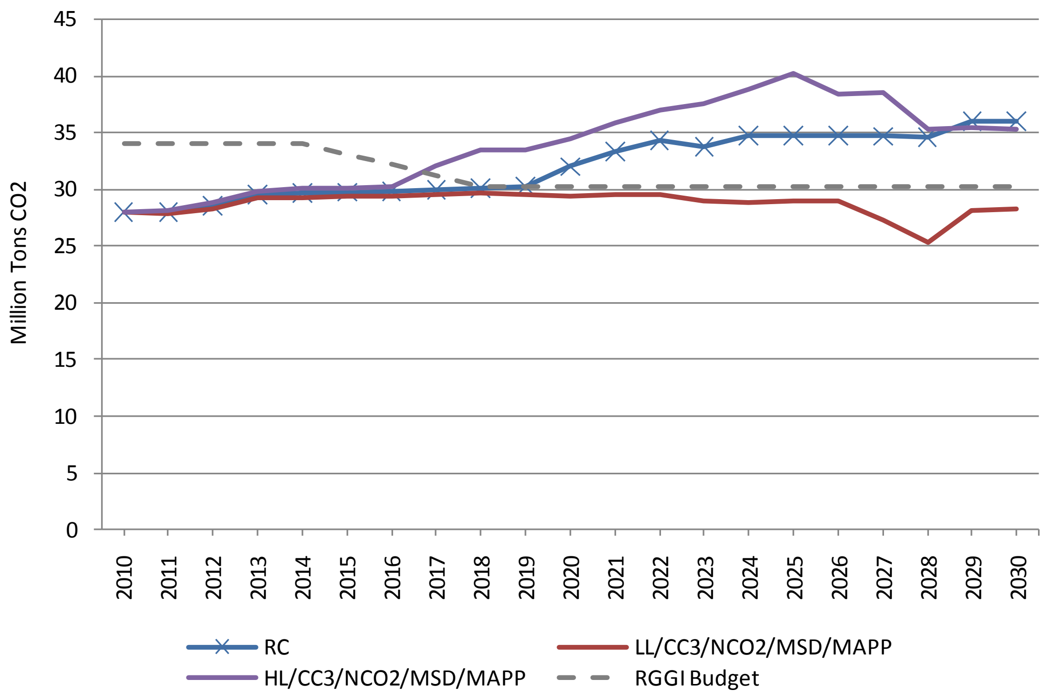


Table 8.4, below, summarizes coal and natural gas usage in Maryland in 2030. In 2030, Maryland uses a little over 8 million mmBtu less coal as a generation fuel under carbon price scenarios as compared to the LTER Reference Case.

Table 8.4
Fuel Use in Maryland in 2030 Under High and Low Load Scenarios

Scenario	Coal (mmBtu)	Natural Gas (mmBtu)
RC	292,159,864	93,701,484
LL	291,856,002	70,345,273
LL+MSD	291,835,123	67,734,564
LL/CC3/NCO2/MSD/MAPP	283,889,900	81,873,251
HL	292,246,004	155,862,281
HL+MSD	292,127,564	89,874,599
HL/CC3/NCO2/MSD/MAPP	283,982,039	199,765,183

8.7 Results

The following key results are based on the modeling and analysis presented in this chapter:

- Under conditions of high load growth, PJM adds between 51,900 and 57,600 MW of new capacity over the 20-year forecast period, compared with capacity additions of 30,100 MW under the LTER Reference Case.
- Under conditions of low load growth, PJM adds between 8,100 and 15,00 MW of new capacity by 2030, compared to the 30,100 MW of new capacity added under the LTER Reference Case assumptions.
- Net imports for PJM-SW decline significantly relative to the LTER Reference Case under both high and low load growth scenarios where the scenarios also include national carbon legislation and the construction of Calvert Cliffs 3, the MAPP transmission line, and the Mt. Storm to Doubs transmission line expansion. Under the high load scenario with CC3/NCO2/MSD/MAPP assumptions, PJM-SW becomes a net exporter in the years 2025 through 2028.
- Under all high load scenarios, PJM-MidE net imports after 2016 are above those in the LTER Reference Case and in all low load scenarios, net imports are below those for the LTER Reference Case after 2016.
- In the second half of the study period, net exports from PJM-APS are below those for the LTER Reference Case in the low load growth scenarios and above those for the LTER Reference Case in the high load growth scenarios.
- Energy prices in PJM-SW under the low load growth scenarios are below those in the LTER Reference Case through 2021, then climb slightly above the LTER Reference Case energy prices for the last six years of the study period. Energy prices under high load growth conditions are slightly above those in the LTER Reference Case through 2017 and then dip below the LTER Reference Case prices through 2029. During the

last eight years of the study period, energy prices in PJM-SW in the high load scenario are below those shown for the low load scenario.

- Energy prices in all scenarios containing a national carbon legislation assumption are above the LTER Reference Case energy prices in all three zones of which Maryland is a part (PJM-SW, PJM-MidE, PJM-APS).
- Capacity prices in all three Maryland zones remain low in the low load growth scenarios until the later years of the study period, and then increase with the need for new plant construction. Capacity prices under the high load growth assumption increase in the mid- to late 2010s and remain at relatively high levels through the remainder of the study period.
- Maryland emissions of SO_2, NO_x, and mercury under all load growth scenarios remain below the HAA caps in all years.
- Maryland SO_2 emissions for HAA plants under the low load scenarios is about 4,500 tons per year below those for the LTER Reference Case and the high load scenarios between 2016 and 2024. For other years, SO_2 emissions in all scenarios considered are approximately equivalent.
- Maryland CO_2 emissions for the low load growth scenarios that exclude a national carbon legislation component are below the LTER Reference Case emissions between 2020 and 2030, and are approximately equal to the LTER Reference Case CO_2 emissions levels in prior years. These low load growth scenarios show emissions of CO_2 below the RGGI budget until 2025/2026, when emissions for the last three years of the study period begin to converge towards the LTER Reference Case result.
- In-State CO_2 emissions in Maryland under the LTER Reference Case adjusted for high load growth are above the RGGI budget beginning in 2017 and remain above the budget for the remainder of the study period. With the inclusion of the MSD upgrade, CO_2 emissions are reduced; however, as in the LTER Reference Case, CO_2 emissions exceed the RGGI budget throughout the 2020s.

- With the introduction of national carbon legislation, Calvert Cliffs 3, MAPP, and the Mt. Storm to Doubs upgrade, the low load growth scenario results in Maryland CO_2 emissions below the RGGI budget in all years. The high load growth scenario, however, shows CO_2 emissions in excess of the budget beginning in 2017. Although the emissions begin to decline in the last five years of the study period, under this scenario emissions remain above the RGGI budget through 2030.

9. HIGH RENEWABLES ALTERNATIVE SCENARIOS

9.1 Introduction

The High Renewables scenarios examine the impacts of building renewable generation resources to satisfy the requirements of a 30 percent Renewable Energy Portfolio Standard ("RPS") in Maryland. Under this scenario it is assumed that the Maryland solar RPS requirement of 2 percent will be met by 2030 with solar Renewable Energy Certificates ("RECs") rather than through the Alternative Compliance Payment ("ACP") mechanism. Current Maryland RPS regulations do not require non-solar renewable energy resources to be sited in Maryland. However, under the high renewables scenarios the LTER assumes the additional RPS requirements will be comprised of solar, on-shore wind, and off-shore wind all located within the State. On-shore wind development is specified at 75 percent of the estimated maximum on-shore wind potential in Maryland, with 70 percent of the added wind facilities to be located in PJM-APS and 30 percent in PJM-MidE. The remaining renewable energy will come from off-shore wind development located in PJM MidE (off the Maryland coast). In aggregate, these result in 1,158 MW of solar, 1,220 MW of on-shore wind, and 2,500 MW of off-shore wind by 2030. Renewable resources are added in blocks to simulate actual project development on a year-to-year basis; as the RPS requirements ramp up to 30 percent by 2030, renewable resources are assumed to come on-line to meet the gradually increasing requirement. Table 9.1, below, shows the annual build-out of renewable capacity to meet the High Renewables RPS requirements.

Table 9.1
High Renewables Scenarios Cumulative Renewable Energy Capacity Additions in Maryland (MW)

Year	Solar	Onshore Wind	Off-shore Wind	Other*
2010	0	16	0	118
2011	30	110	0	118
2012	130	190	0	238
2013	201	190	0	238
2014	247	190	0	238
2015	294	190	0	238
2016	341	190	0	238
2017	387	190	0	238
2018	459	190	0	238
2019	618	190	0	238
2020	785	190	0	238
2021	976	293	500	238
2022	1,068	396	500	238
2023	1,079	499	1,000	238
2024	1,094	602	1,000	238
2025	1,103	705	1,000	238
2026	1,115	808	1,500	238
2027	1,125	911	1,500	238
2028	1,136	1,014	2,000	238
2029	1,147	1,117	2,000	238
2030	1,158	1,220	2,500	238

*Other includes biomass and landfill gas resources.

9.2 Generating Mix

The LTER Reference Case assumes the non-solar Tier 1 portion of the Maryland RPS will be met by 2020. The solar RPS component will be met through 2018 using solar RECs, but the incremental solar requirement (for years after 2018) will be met through the ACP. By 2022, the year that the solar requirement reaches 2 percent, about half of that requirement will be met using solar RECs and the other half through the ACP. The High Renewables scenarios match projected renewable energy capacity builds in Maryland under the High Renewables assumption are the same as those under the LTER Reference Case through 2017. Incremental new renewable energy capacity in Maryland in the High Renewables scenarios exceeds new renewable capcity under the RC assumptions between 2018 and 2030. Figure 9.1 and Figure 9.2 (both below) show total renewable energy capacity additions under the LTER Reference Case and under the High Renewables scenarios.

Total renewable energy capacity in Maryland in 2030 is just under 4,900 MW in the High Renewables scenario, with on-shore wind accounting for 1,220 MW, off-shore wind accounting for 2,500 MW, and solar accounting for 1,158 MW. By comparison, the LTER Reference Case has 698 MW of renewable energy capacity in Maryland in 2030, with solar accounting for 498 MW, on-shore wind accounting for 80 MW, and no off-shore wind. By 2030, in both the LTER Reference Case and the High Renewables scenario, biomass and landfill gas capacity are 40 MW and 80 MW, respectively.

Figure 9.1 LTER Reference Case: Total RPS Capacity Additions in Maryland

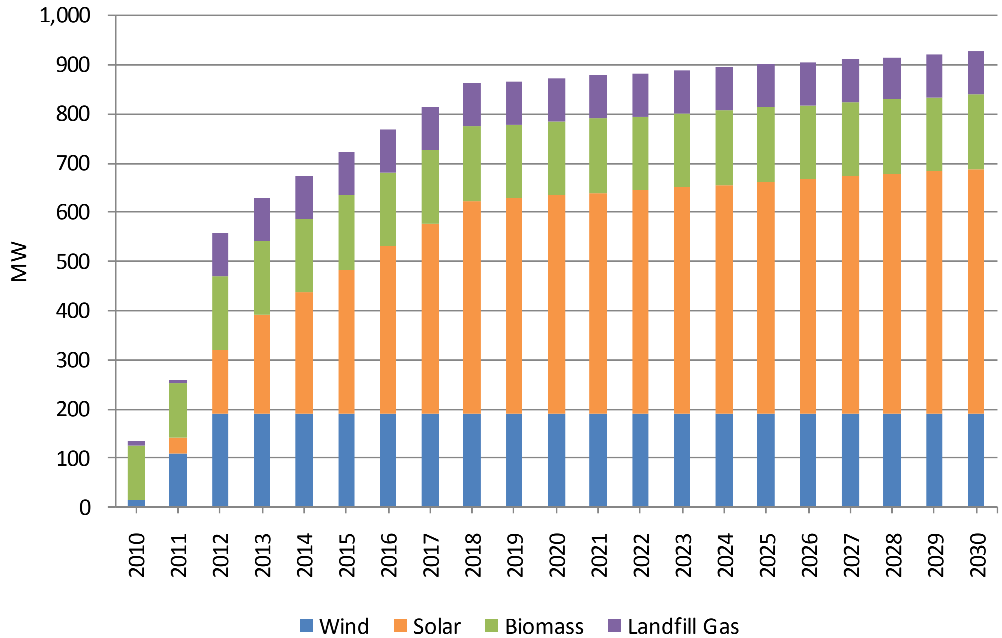
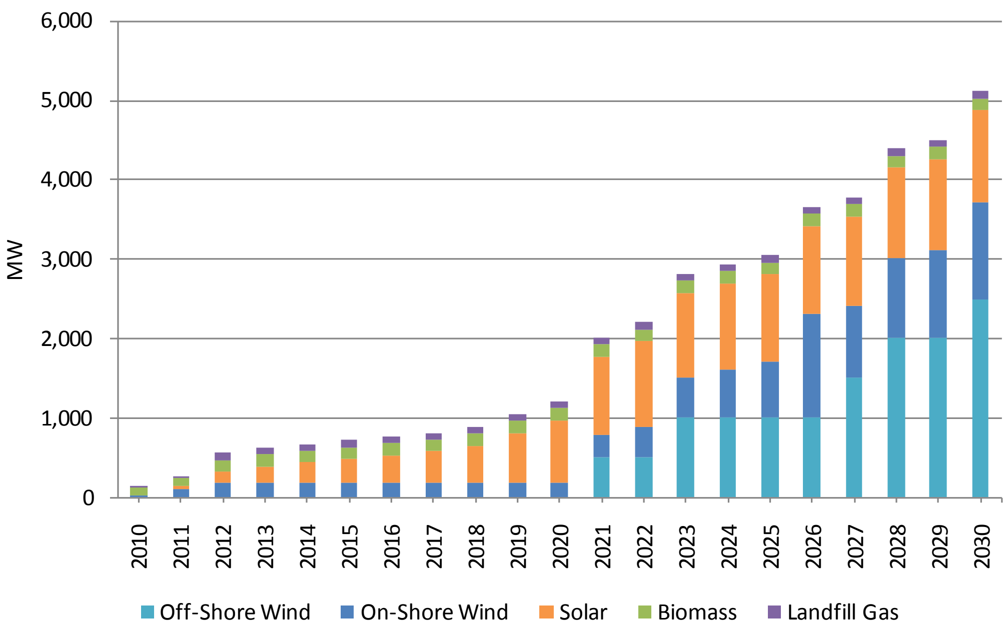


Figure 9.2 High Renewables Scenarios: Total RPS Capacity Additions in Maryland



Renewable energy generation in Maryland reaches almost 16,000 GWh in 2030 in the High Renewables scenarios, more than five times the approximately 2,800 GWh of Maryland renewable energy generation by 2030 in the LTER Reference Case. Of the nearly 16,000 GWh in the High Renewables scenarios, wind accounts for almost 80 percent of the total with about 12,500 GWh, followed by solar with about 1,800 GWh. In the LTER Reference Case, biomass has the most generation of any renewable energy technology in Maryland, followed by solar, wind and landfill methane. Figure 9.3 and Figure 9.4 (both below) show the renewable generation in Maryland under the LTER Reference Case and the High Renewables scenarios, respectively.

Figure 9.3 LTER Reference Case: Renewable Energy Generation in Maryland

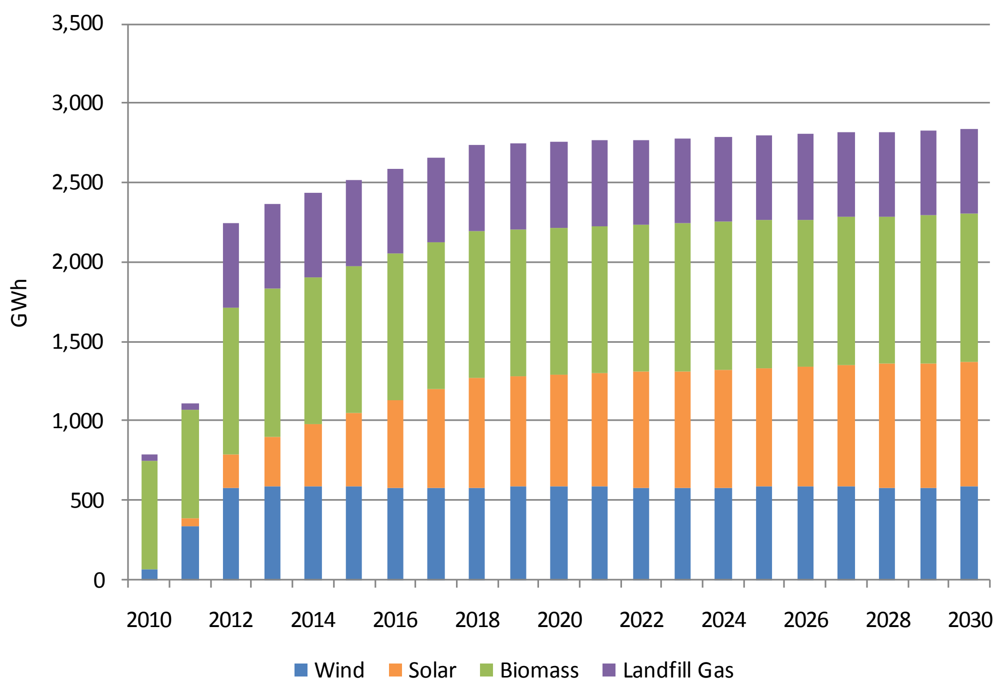
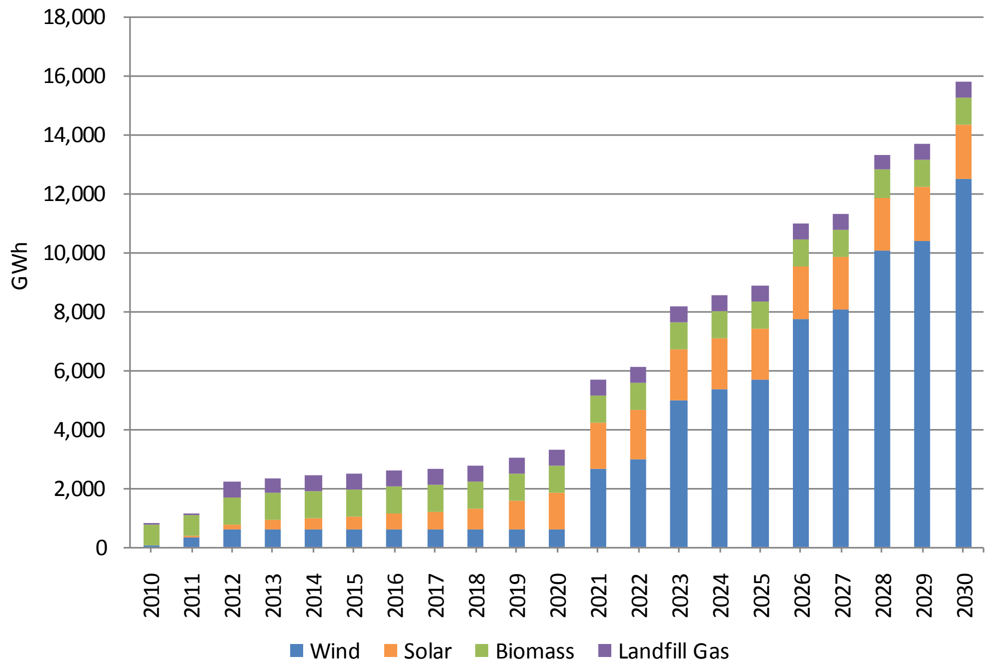


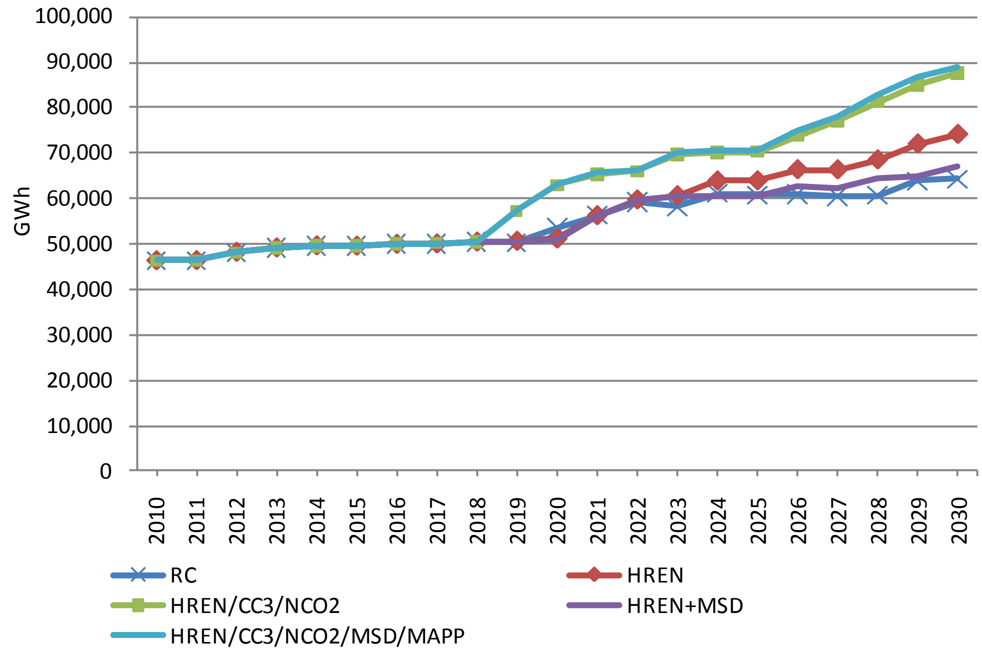
Figure 9.4 High Renewables Scenarios: Renewable Generation in Maryland



Renewable energy generation increases significantly in Maryland due to the assumption that the additional RPS requirement is met with in-State resources. However, the effect on PJM overall is small because generation in Maryland comprises a small part of total PJM generation. Increasing the renewable energy requirement in Maryland from the 20 percent required by the existing Maryland RPS to 30 percent, therefore, essentially increases overall renewable energy requirements (as a percentage of PJM consumption) by less than 1 percent.

Figure 9.5, below, shows annual generation in Maryland for the LTER Reference Case and for the four alternative High Renewables scenarios. Total Maryland generation in the High Renewables scenarios increases relative to the LTER Reference Case because of the additional generation from renewable resources, which are assumed to be located in Maryland.

Figure 9.5 Annual Generation in Maryland Under High Renewables Scenarios



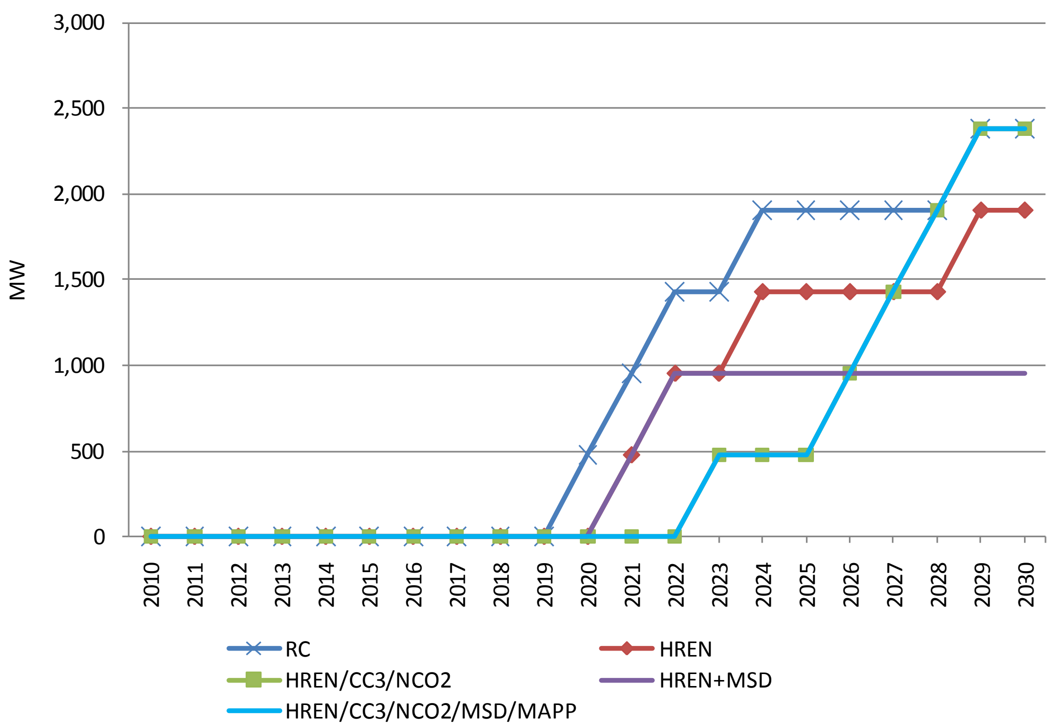
As shown in Figure 9.5, generation in Maryland increases modestly in the High Renewables scenario that also incorporates the upgrade to the Mt. Storm to Doubs transmission line ("HREN+MSD") and the High Renewables scenario based on the LTER Reference Case with modification only to the Maryland RPS ("HREN"). In the HREN+MSD scenario, the additional Maryland generation attributable to the development of new renewable resources in the State is off-set by imports from PJM-APS facilitated by the Mt. Storm to Doubs transmission line, which puts downward pressure on fossil-fuel generation in PJM-SW.

Total generation increases more substantially in the High Renewables scenario that includes Calvert Cliffs 3 and national carbon legislation ("HREN/CC3/NCO2"), and the High renewables scenario that includes Calvert Cliffs 3, national carbon legislation, the Mt. Storm to Doubs line, and the MAPP line ("HREN/CC3/NCO2/MSD/MAPP"). This increase, however, is largely attributable to the operation of the Calvert Cliffs 3 nuclear plant.

9.3 Plant Additions and Retirements

Figure 9.6, below, shows the projected natural gas capacity additions in PJM-SW for the LTER Reference Case and the High Renewables scenarios. The additional renewable energy resources reduce the need for new natural gas capacity additions and delay the builds for one year, with the first natural gas plant added in 2021 in the High Renewables case compared to 2020 in the LTER Reference Case. Under the HREN+MSD scenario the need for new natural gas fired capacity is reduced further as the Mt. Storm to Doubs transmission upgrade facilitates in increase in net imports into PJM-SW from PJM-APS.

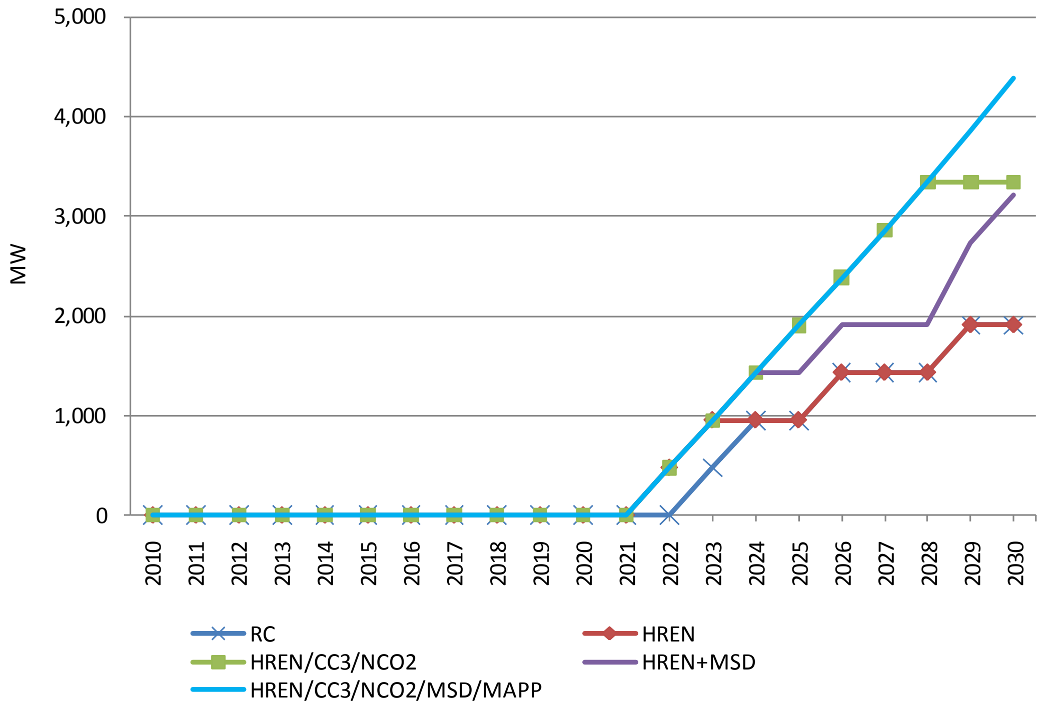
Figure 9.6 PJM-SW Natural Gas Capacity Additions



Under the scenarios that include Calvert Cliffs 3, the need for new natural gas capacity is delayed by three years to 2022 compared to the LTER Reference Case. However, projected natural gas capacity additions ultimately converge to the LTER Reference Case by 2028 as additional natural gas capacity is required to replace the coal generation lost from retirements and retrofits arising from the implementation of national carbon legislation.

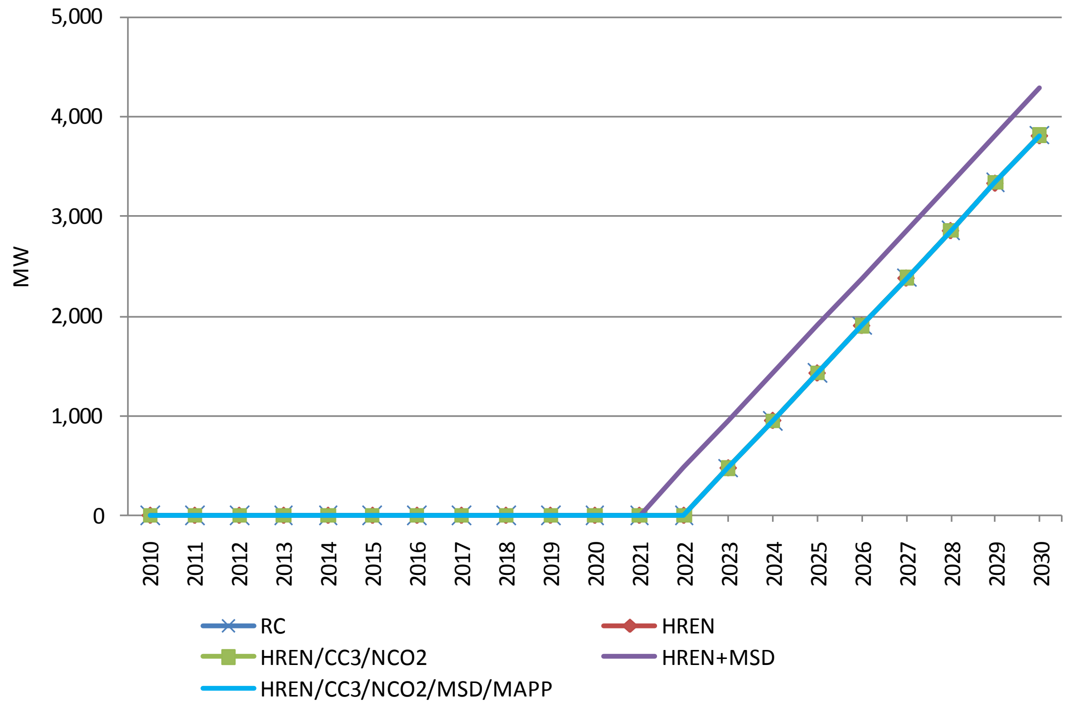
Figure 9.7, below, shows the natural gas capacity additions in PJM-MidE. Capacity additions in PJM-MidE begin a year earlier in the High Renewables scenarios compared to the LTER Reference Case as opportunities to import energy are reduced due to the delayed natural gas builds in PJM-SW. As in PJM-SW, under the scenarios with national carbon legislation, PJM-MidE builds additional capacity to replace coal generation lost due to retirements and retrofits. In the HREN+MSD scenario, PJM-MidE builds additional natural gas capacity compared to the LTER Reference Case due to the reduced opportunity for imports from PJM-SW. PJM-SW builds less new internal capacity since it is able to satisfy load growth requirements by importing from PJM-APS.

Figure 9.7 PJM-MidE Natural Gas Capacity Additions



For PJM-APS, the level and timing of capacity additions do not change between the LTER Reference Case and the other scenarios, with one exception: the HREN+MSD scenario adds projected generating capacity a year earlier, and this additional capacity accommodates exports to PJM-SW (see Figure 9.8 below).

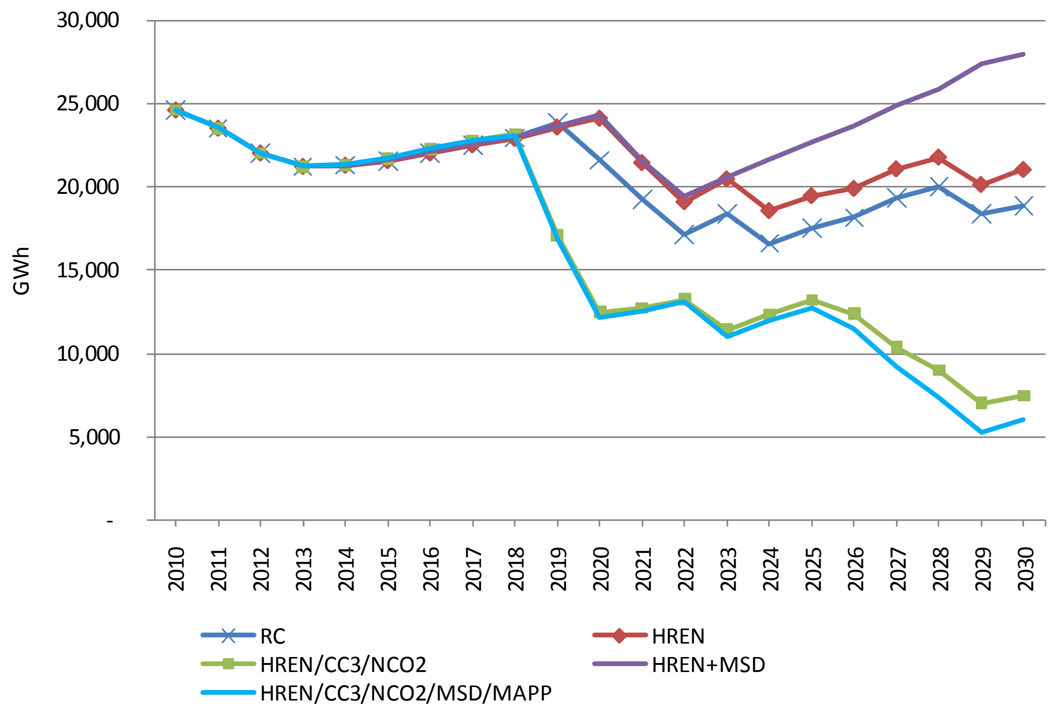
Figure 9.8 PJM-APS Natural Gas Capacity Additions



9.4 Net Energy Imports

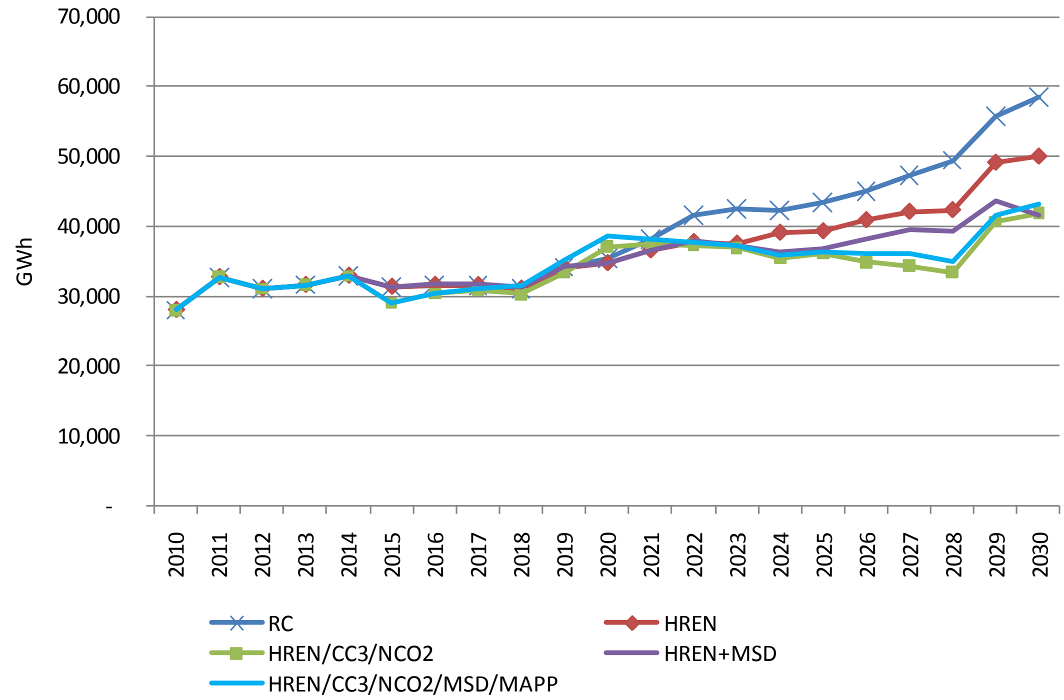
Net energy imports increase for PJM-SW in the High Renewables scenario as compared to the LTER Reference Case, but the difference is relatively modest and is attributable to the deferral of a natural gas, combined cycle unit in the High Renewables scenario relative to the LTER Reference Case (see Figure 9.9). Net imports under the HREN+MSD scenario increase significantly due to the additional imports from PJM-APS made available to PJM-SW by the Mt. Storm to Doubs transmission line. In contrast, net energy imports drop sharply in 2019 in the HREN/CC3/NCO2 and HREN/CC3/NCO2/MSD/MAPP scenarios when Calvert Cliffs Unit 3 comes on-line and additional capacity is built to replace coal generation reductions. Net imports of energy in the HREN/CC3/NCO2 and HREN/CC3/NCO2/MSD/MAPP scenarios drop from about 25,000 GWh in 2010 to about 6,000 to 7,000 GWh by 2030.

Figure 9.9 PJM-SW Net Imports



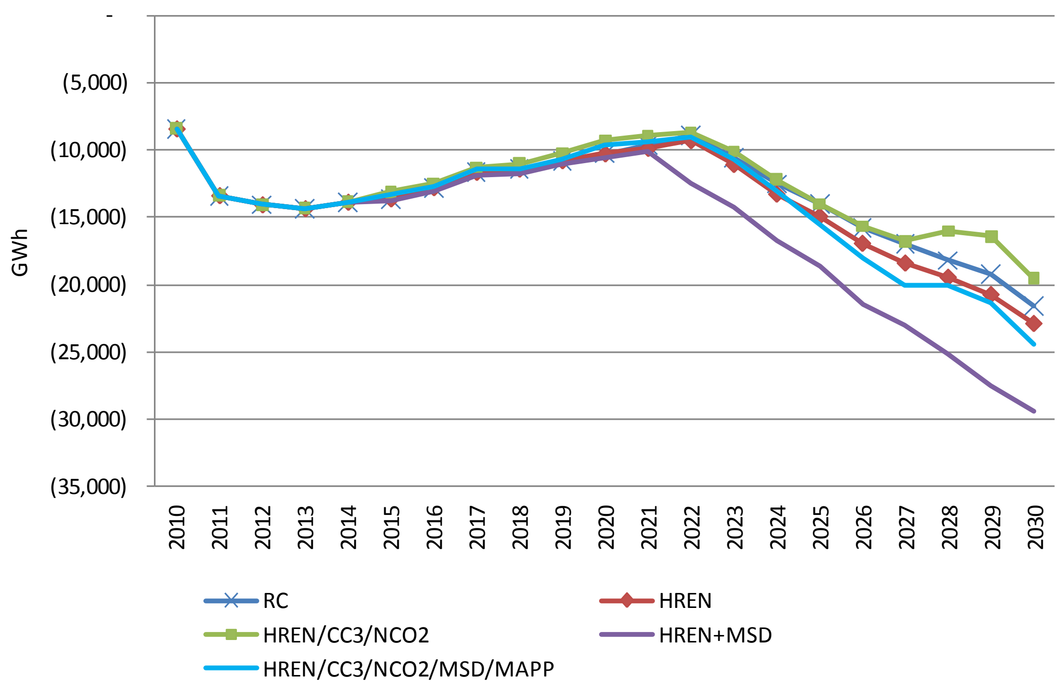
In contrast, net energy imports for PJM-MidE for the High Renewables, HREN+MSD, HREN/CC3/NCO2, and HREN/CC3/NCO2/MSD/MAPP scenarios (shown in Figure 9.10 below) are below that of the LTER Reference Case beginning in 2021 and continuing to 2030. The decrease in net energy imports is not as significant for the HREN/CC3/NCO2 and HREN/CC3/NCO2/MSD/MAPP scenarios for PJM-MidE as it is with PJM-SW.

Figure 9.10 PJM-MidE Net Imports



PJM-APS remains a net exporter throughout the study period for the LTER Reference Case and the High Renewables scenarios. Exports increase in the HREN+MSD scenario beginning in 2021 due to increased transmission capacity into PJM-SW, while the HREN, HREN/CC3/NCO2/MSD/MAPP, and HREN/CC3/NCO2 scenarios track closely with the LTER Reference Case throughout the study period (see Figure 9.11 below).

Figure 9.11 PJM-APS Net Imports



9.5 Fuel Use

Given the renewable energy build-out location assumptions contained in the High Renewables scenarios, the share of renewable energy generation in Maryland grows from approximately 2 percent in 2010 to 18 percent in 2030 for the HREN/CC3/NCO2 and HREN/CC3/NCO2/MSD/MAPP scenarios, and to 21 percent and 24 percent in 2030 in the HREN and HREN+MSD scenarios, respectively, as compared to 4 percent in the LTER Reference Case. The share of coal generation in Maryland decreases to between 31 percent (in the HREN/CC3/NCO2/MSD/MAPP scenario) and 46 percent by 2030 in the HREN+MSD scenario, compared to 48 percent in the LTER Reference Case. The contribution of natural gas to Maryland's generation mix still grows, though not as much as in the LTER Reference Case.

Natural gas generation ranges from 5 percent in the HREN+MSD scenario to 18 percent in the HREN/CC3/NCO2/MSD/MAPP scenario, compared to 21 percent in the LTER Reference Case. Even with the addition of Calvert Cliffs 3 in the HREN/CC3/NCO2 and HREN/CC3/NCO2/MSD/MAPP scenarios, the contribution of nuclear power to Maryland's generation mix declines from 2010 levels and further declines in the HREN and HREN+MSD scenarios because of the additional generation from renewable energy resources in the State. Table 9.2 below provides these results in tabular form.

Table 9.2
Fuel Shares of Generation in Maryland

Year	Scenario	Total Generation (GWh)	Percent Gas	Percent Coal	Percent Nuclear	Percent Renewables	Percent Hydro
2010	All	46,389	2	60	32	2	5
2015	RC	49,576	1	60	29	5	5
	HREN	49,576	1	60	29	5	5
	HREN/CC3/NCO2	49,678	1	60	29	5	5
	HREN+MSD	49,545	1	60	29	5	5
	HREN/CC3/NCO2/MSD/MAPP	49,647	1	60	29	5	5
2020	RC	53,478	5	58	27	5	4
	HREN	51,153	1	59	29	6	4
	HREN/CC3/NCO2	63,035	<1	47	43	5	4
	HREN+MSD	51,022	1	59	29	6	4
	HREN/CC3/NCO2/MSD/MAPP	63,344	<1	47	43	5	4
2025	RC	60,785	17	51	24	5	4
	HREN	63,900	12	48	23	14	4
	HREN/CC3/NCO2	70,327	2	43	39	13	3
	HREN+MSD	60,660	7	51	24	15	4
	HREN/CC3/NCO2/MSD/MAPP	70,766	2	43	39	13	3
2030	RC	64,291	21	48	23	4	4
	HREN	74,077	14	41	20	21	3
	HREN/CC3/NCO2	87,626	16	32	31	18	3
	HREN+MSD	67,104	5	46	22	24	3
	HREN/CC3/NCO2/MSD/MAPP	89,099	18	31	31	18	3

Coal consumption remains basically the same as the LTER Reference Case in the HREN, HREN+MSD, HREN/CC3/NCO2, and HREN/CC3/NCO2/MSD/MAPP scenarios. Natural gas consumption is sharply lower by 2030 in the HREN+MSD scenario compared to the LTER Reference Case because of higher power imports in PJM-SW from PJM-APS, while natural gas consumption in the HREN scenario are more than 20 percent lower than in the LTER Reference Case by 2030. Natural gas consumption in the HREN/CC3/NCO2/MSD/MAPP scenario remains at or close to 2010 levels until 2022, then increase beginning in 2025 as load growth absorbs the added generation from Calvert Cliffs 3. Natural gas consumption in the HREN/CC3/NCO2 scenario follows this same pattern but ultimately is just above projected natural gas consumption in the LTER Reference Case by 2030. These results are depicted in Figure 9.12 and Figure 9.13 (both below).

Figure 9.12 Coal Use for Electricity Generation in Maryland

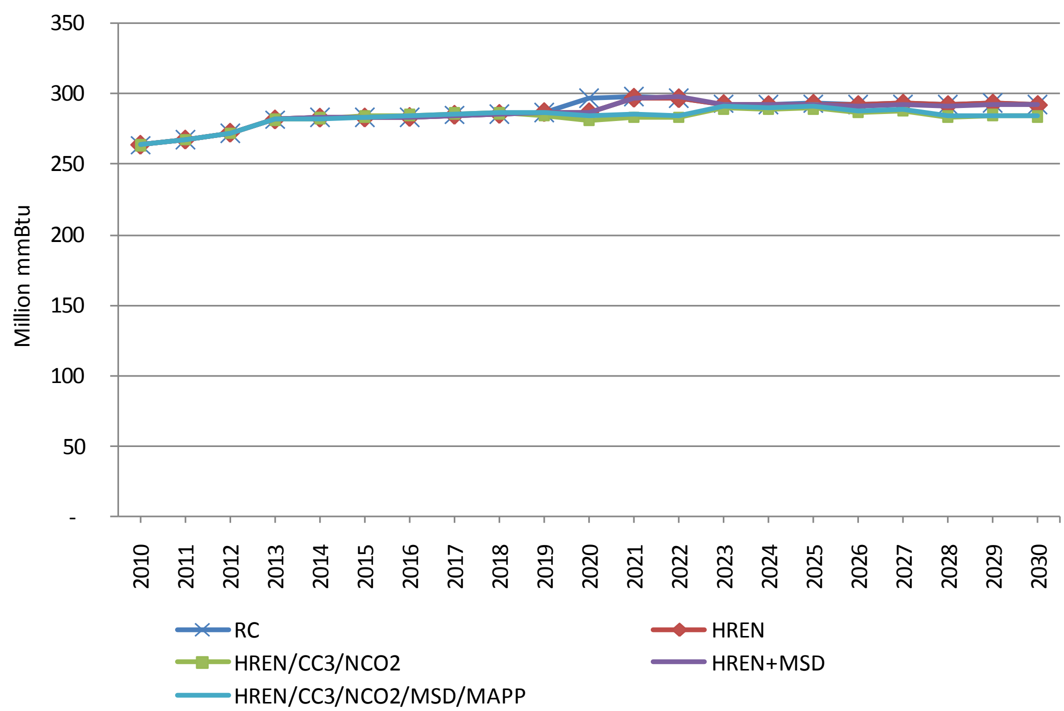
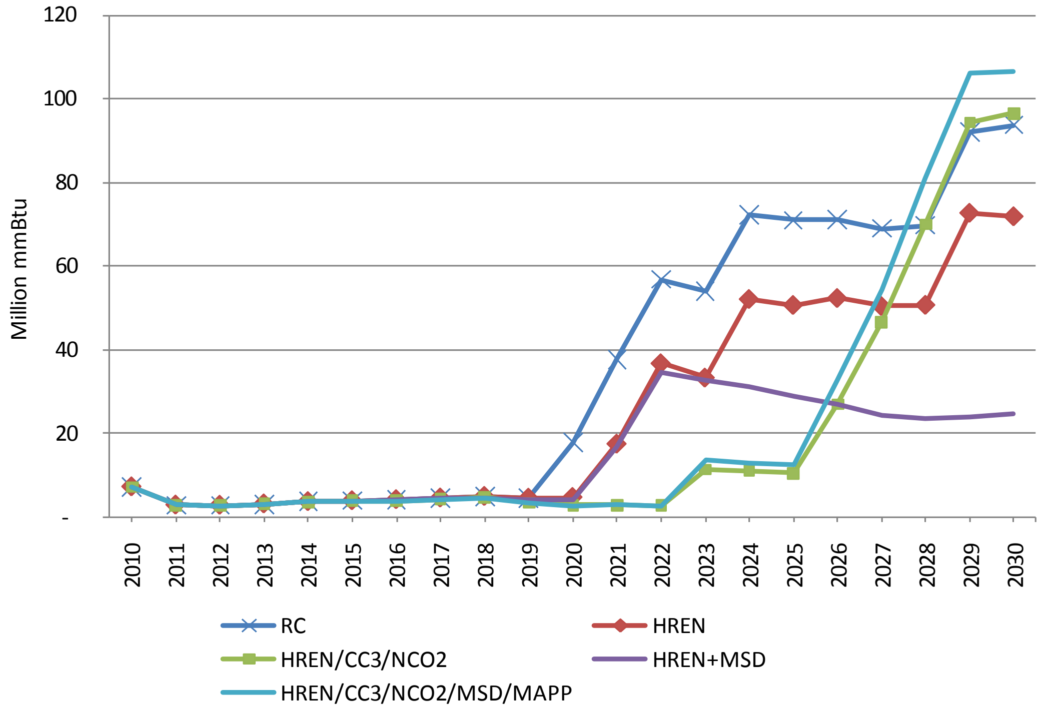


Figure 9.13 Natural Gas Use for Electricity Generation in Maryland



9.6 Energy Prices

Maryland's implementation of a higher RPS requirement has virtually no impact on wholesale energy prices. The fundamental reason is that renewables are infra-marginal in the dispatch order, and therefore do not set price. As shown below in Figure 9.14, Figure 9.15, and Figure 9.16, the wholesale energy prices for the LTER Reference Case in PJM-SW, PJM-APS, and PJM-MidE, respectively, are almost identical to the LTER Reference Case adjusted for a higher Maryland RPS. There are higher prices associated with the High Renewables scenarios that incorporate national carbon legislation, but that difference is due to the carbon price rather than to the higher level of renewable generation required in Maryland.

Figure 9.14 PJM-SW Real All-Hours Energy Price

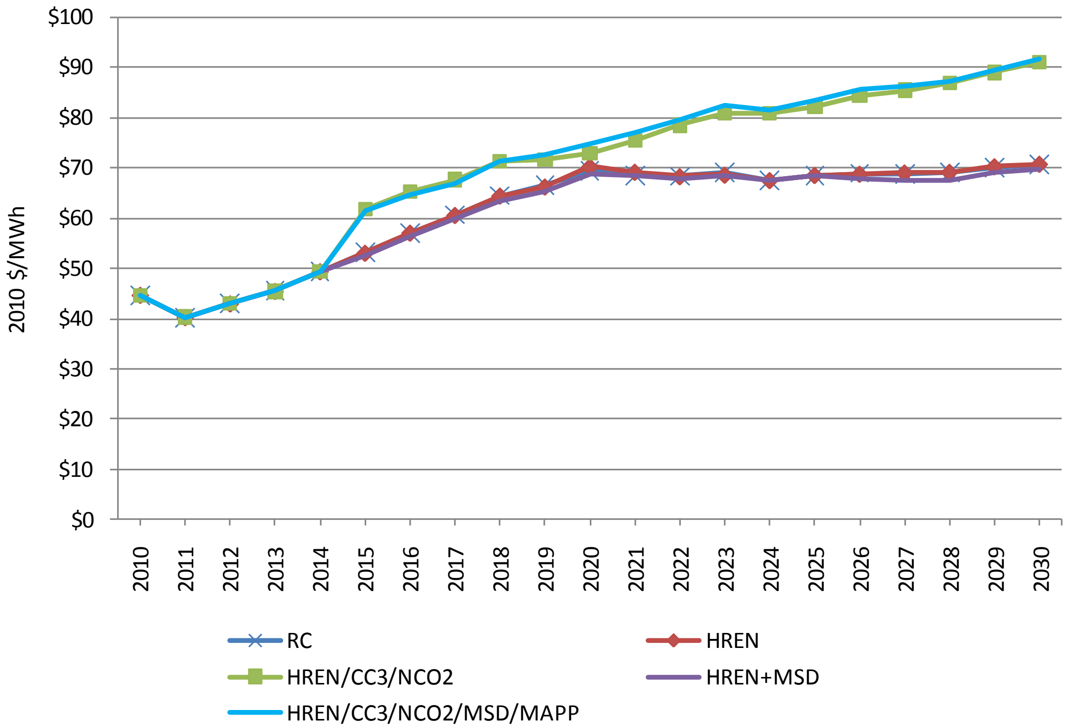


Figure 9.15 PJM-MidE Real All-Hours Energy Price

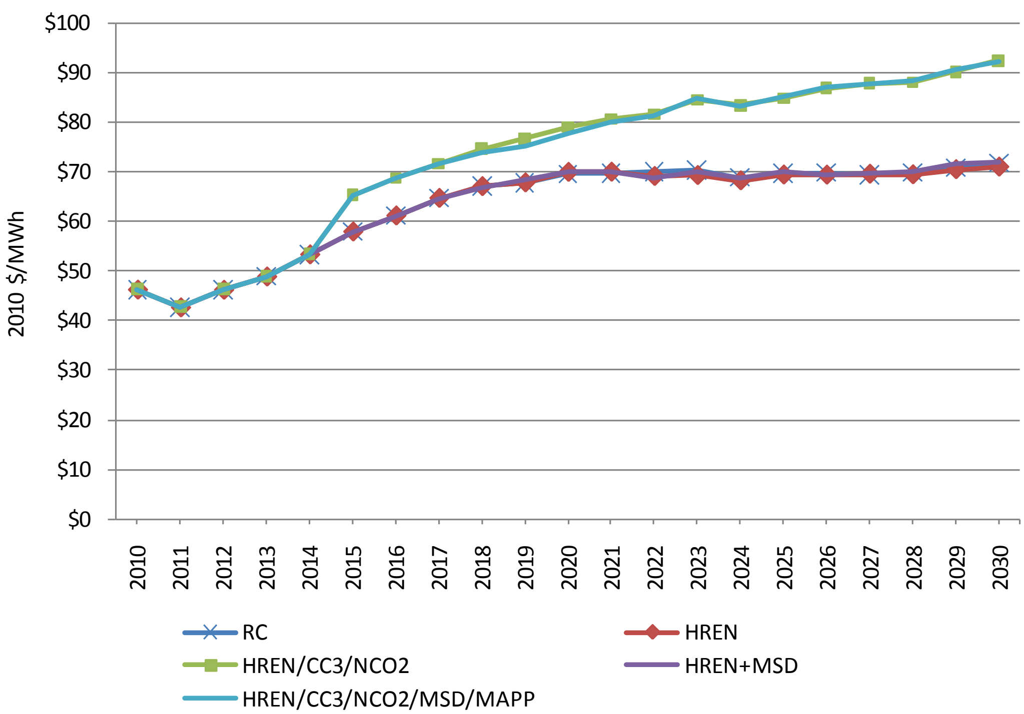
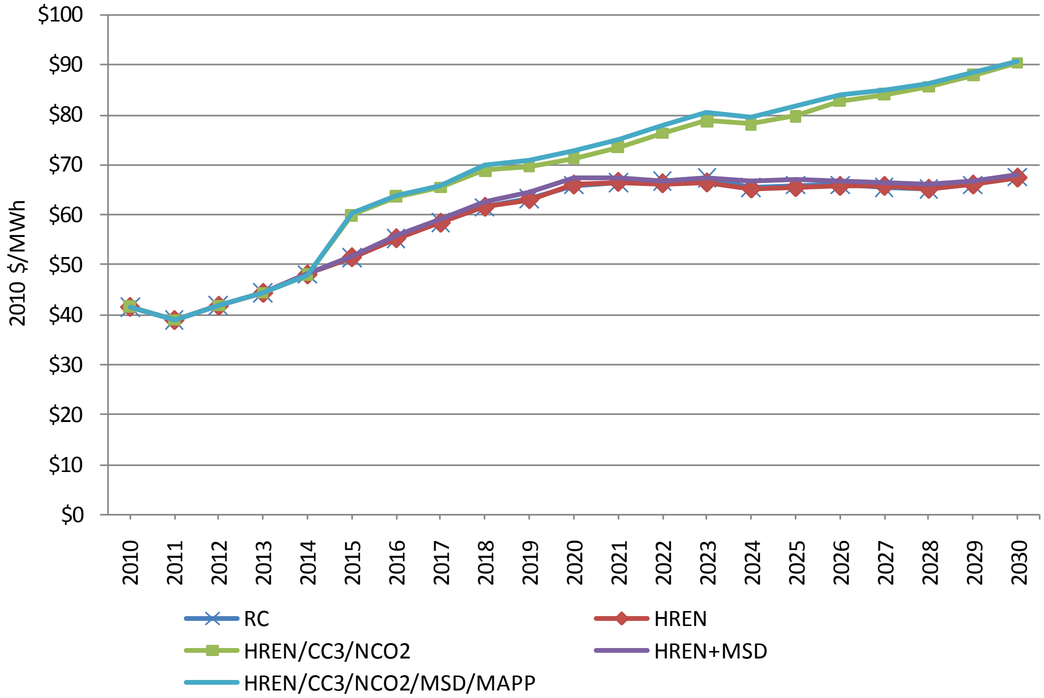


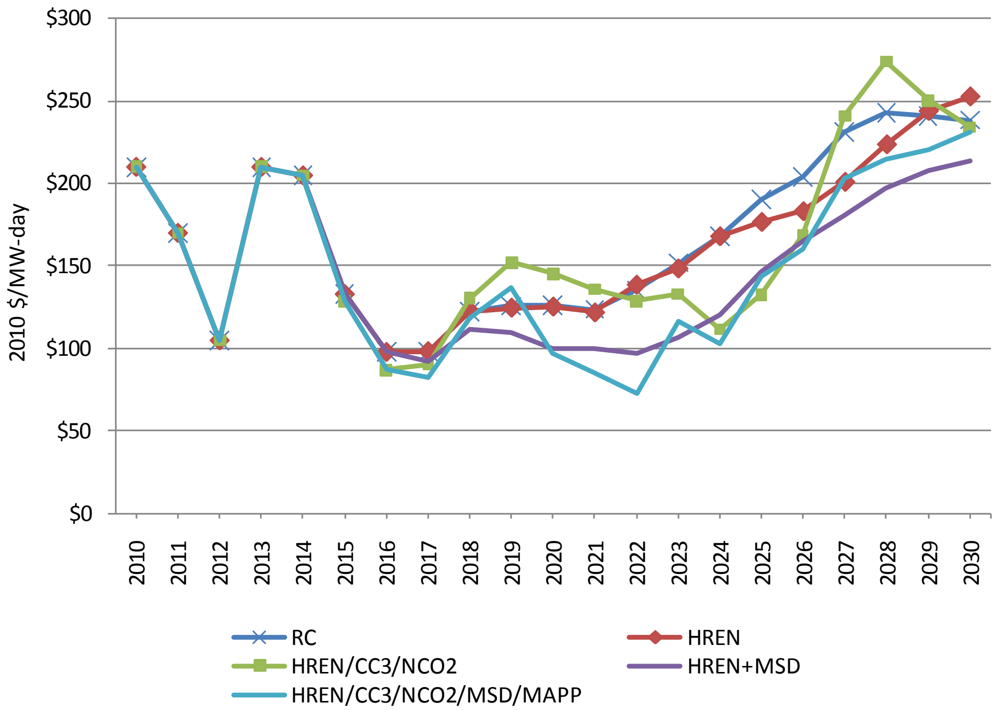
Figure 9.16 PJM-APS Real All-Hours Energy Price



9.7 Capacity Prices

As shown in Figure 9.17 below, there is no systematic or sustained difference in simulated capacity prices in PJM-SW under the LTER Reference Case compared to the HREN scenario (excluding infrastructure changes and national carbon legislation). For most years, the PJM-SW capacity prices under these two scenarios are the same, although in the mid-2020s, the capacity prices for the HREN scenario are below the LTER Reference Case capacity prices by as much as $30 per MW-day. By the final year of the study period, PJM-SW capacity prices under the HREN scenario are slightly above the LTER Reference Case capacity prices. This difference is related to the schedule of natural gas plant build-outs and is not indicative of a meaningful divergence. Following the end of the 20-year study period, we anticipate that the capacity prices under these two scenarios would converge, as differences in the natural gas plant build-out schedule will disappear.

Figure 9.17 PJM-SW Capacity Prices

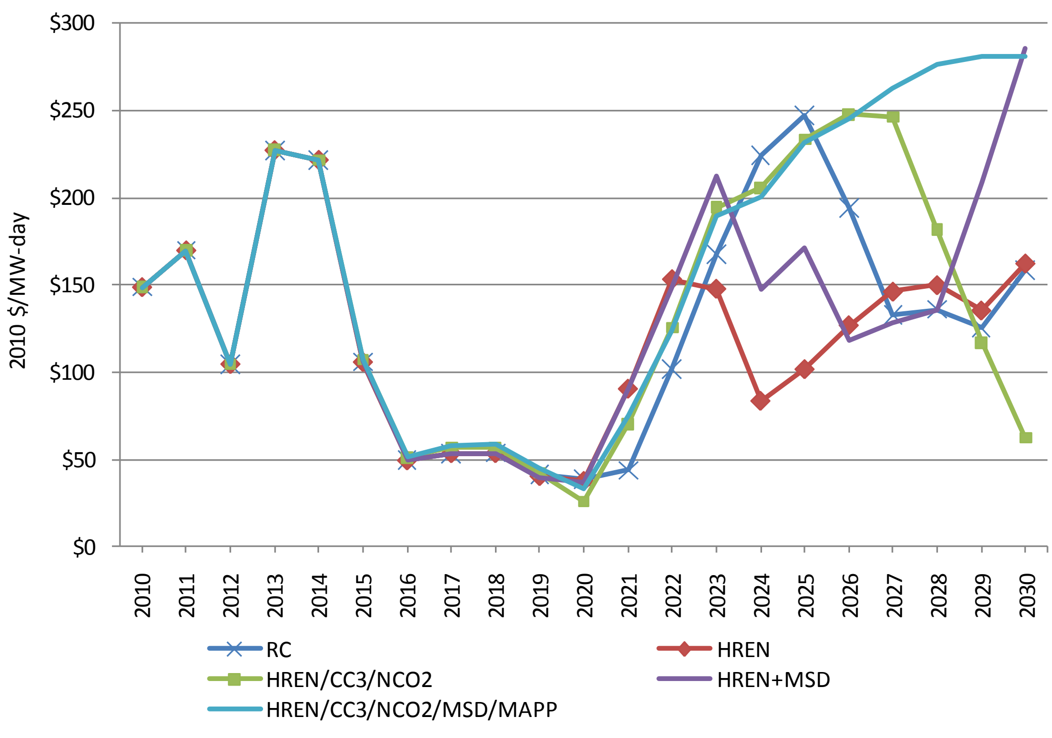


Both of the High Renewables scenarios that include construction of the Mt. Storm to Doubs transmission line are characterized by PJM-SW capacity prices below those shown for the LTER Reference Case. This difference is largely attributable to the increased import capability (from PJM-APS) accommodated by the Mt. Storm to Doubs line, which puts downward pressure on capacity prices in PJM-SW. Additional downward pressure on capacity prices is also provided by the operation of a third unit at Calvert Cliffs.

For the High Renewables scenario that includes Calvert Cliffs 3 and national carbon legislation, capacity prices in PJM-SW drop below the LTER Reference Case results due to the introduction of Calvert Cliffs 3. After load grows into the additional capacity provided by the new nuclear unit, capacity prices return to levels close to the LTER Reference Case capacity prices.

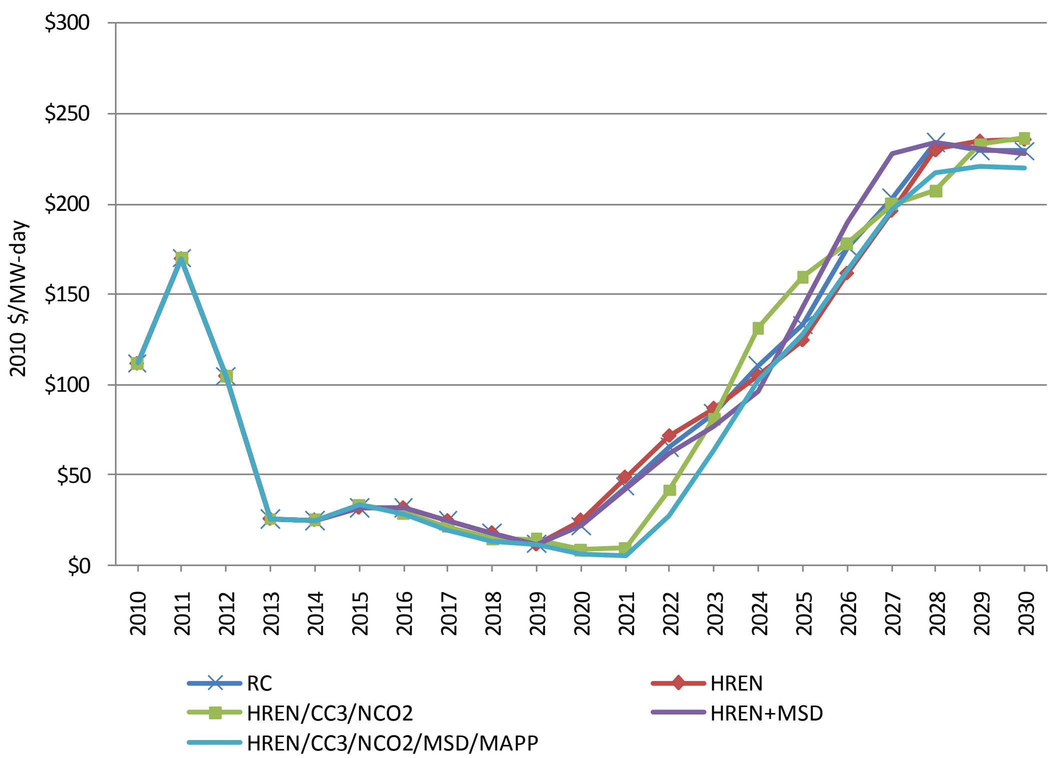
The same basic relationship between the PJM-SW capacity prices for the LTER Reference Case and the HREN scenario exists for PJM-MidE (see Figure 9.18 below). The HREN scenario exhibits lower capacity prices in the mid-2020s as a result of higher renewable build-out, but for the earlier years of the study period, there is very little difference in capacity prices between these scenarios. Towards the end of the study period, the capacity prices converge.

Figure 9.18 PJM-MidE Capacity Prices



With respect to capacity prices in PJM-APS, shown in Figure 9.19 below, there is no sustained systematic differences for any of the scenarios. The capacity-related impacts associated with the increase in Maryland RPS requirements are too small to have any significant influence on capacity prices in the PJM-APS zone. The introduction of Calvert Cliffs 3 in PJM-SW has a depressing effect on capacity prices in PJM-APS for several years following the initial on-line date of the plant due to reductions in the exports to PJM-SW from PJM-APS, but the capacity prices in PJM-APS converge towards the end of the study period.

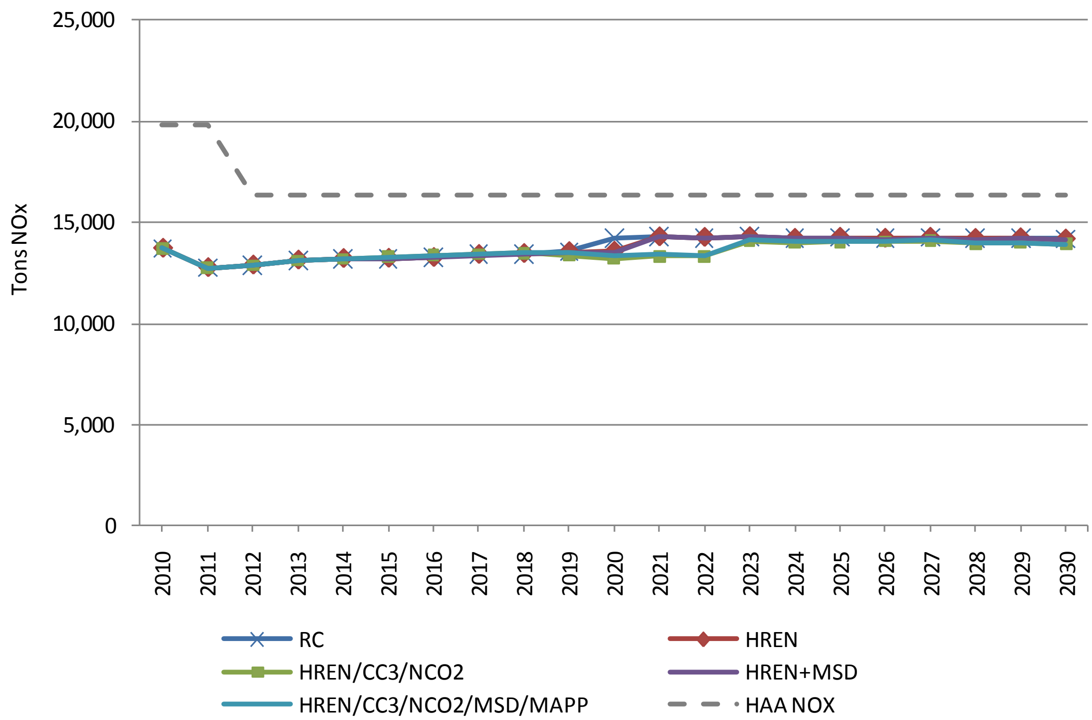
Figure 9.19 PJM-APS Capacity Prices



9.8 Emissions

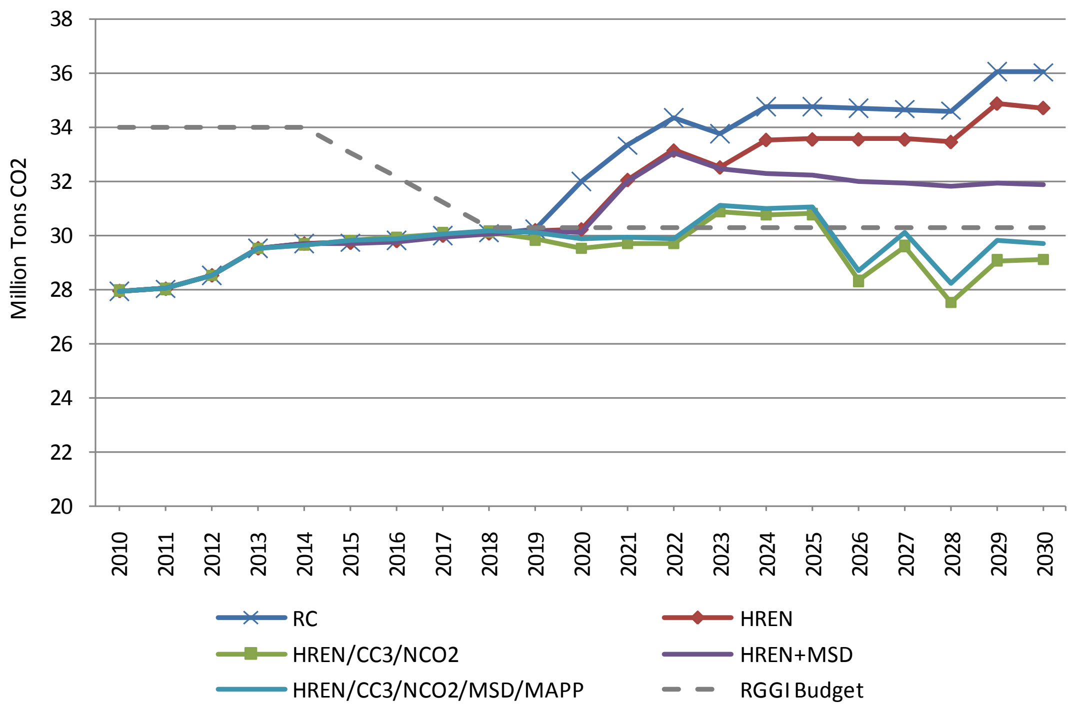
Because the High Renewables scenario delays the addition of a new natural gas plant by one year relative to the LTER Reference Case, NO_x emissions in the HREN scenario are the same as the LTER Reference Case for all years except 2020, where a slight difference exists due to the timing of the build-out. The HREN/CC3/NCO2 scenario avoids new natural gas generation builds for several years following the initial on-line date of Calvert Cliffs 3, which results in reduced NO_x emissions between 2019 and the early 2020's. After that time, NO_x emissions in this scenario generally converge with those shown for the LTER Reference Case (see Figure 9.20 below).

Figure 9.20 NO_x Emissions from Coal Plants Subject to HAA



As shown in Figure 9.21 below, in-State CO_2 emissions in the HREN scenario are modestly lower than the LTER Reference Case by 2030, resulting from an avoided combined cycle, natural gas plant in the High Renewables scenario. As with the LTER Reference Case, CO_2 emissions in the HREN scenario exceed Maryland's RGGI. By comparison, CO_2 emissions in the HREN+MSD peak in 2022, then decrease to about 32 million tons by 2030 as more generation is imported from PJM-APS. For the High Renewables scenarios that include national carbon legislation CO_2 emissions are substantially lower than for the LTER Reference Case and also below the RGGI budget for most of the study period.

Figure 9.21 Maryland CO_2 Emissions



9.9 Results

Increasing Maryland's RPS requirement from 20 percent by 2020 to 30 percent by 2030 entails the following results for Maryland relative to the LTER Reference Case: (1) reductions in CO_2 emissions, (2) increased diversity of power supply (see Chapter 13 for a complete discussion), (3) reduced natural gas consumption, and (4) reduced capacity costs for some of the years included in the study period. The principal results emerging from the modeling analysis related to implementation of a higher RPS in Maryland are:

- Renewable energy generation increases significantly in Maryland in the High Renewables scenarios, but the effect on PJM is small, as Maryland generation comprises a small part of PJM total generation.
- Renewable energy generation in Maryland in the High Renewables scenarios is more than five times that of renewable energy generation in the LTER Reference Case by 2030. This is due to the assumption that the incremental renewable generation required to meet the 30 percent RPS in Maryland is located within the State.
- Under the HREN and HREN+MSD scenarios, less natural gas capacity is built in PJM-SW relative to the LTER Reference Case. When high renewables are combined with Calvert Cliffs 3, national carbon legislation, the MAPP line, and the Mt. Storm to Doubs upgrade, new natural gas plant construction is delayed by several years but cumulative additions match the LTER Reference Case additions for the last three years of the study period.
- The high renewable assumptions, by themselves, have no significant impact on natural gas plant additions in PJM-MidE or PJM-APS relative to the LTER Reference Case.
- The high renewables build-out in Maryland causes a slight increase in net imports into PJM-SW and PJM-MidE relative to the LTER Reference Case in the second half of the study period but has no significant impact in PJM-APS over the same period.
- Coal consumption in Maryland power plants is largely unaffected by the high renewables assumptions throughout the study period, while natural gas consumption declines significantly relative to the LTER Reference Case from 2020 to 2030.
- The high renewables assumptions have no meaningful impact on wholesale energy prices in PJM-SW, PJM-MidE, or PJM-APS during any time over the study period.
- Capacity prices in PJM-SW under the HREN scenario track the LTER Reference Case capacity prices through 2024, then drop below the LTER Reference Case capacity

prices for five years before again matching the LTER Reference Case at the end of the study period. The same approximate pattern is evident for PJM-MidE.

- There is no significant impact, relative to the LTER Reference Case, on capacity prices in PJM-APS from the high renewables assumptions.
- Maryland CO_2 emissions under the HREN scenario are below the level of CO_2 emissions associated with the LTER Reference Case for years following 2019. Only in the scenarios that include national carbon legislation are Maryland CO_2 emissions under the RGGI budget.

10. AGGRESSIVE ENERGY EFFICIENCY ALTERNATIVE SCENARIOS

10.1 Introduction

Energy efficiency and conservation initiatives have the potential to reduce both energy consumption and peak demand in Maryland and in PJM. The Aggressive Energy Efficiency ("EE") alternative scenarios are designed to assess the impacts of higher levels of achievement of energy conservation than represented in the LTER Reference Case. The EE scenarios were run on the LTER Reference Case and three infrastructure sensitivity cases: EE with the Mt. Storm to Doubs transmission line ("EE + MSD"); EE with Calvert Cliffs 3 and national carbon legislation ("EE/CC3/NCO2"); and EE with Calvert Cliffs 3, national carbon legislation, the Mt. Storm to Doubs transmission line, and the MAPP transmission line ("EE/CC3/NCO2/MSD/MAPP").

The EE scenarios assume that only Maryland implements the more aggressive energy efficiency/conservation policies: other states in PJM (and the Eastern Interconnection) adhere to the same energy efficiency and conservation policies assumed for the LTER Reference Case. For the EE scenarios, the LTER Reference Case load assumptions are altered to include additional energy and demand reductions in Maryland. The reductions are calculated for each Maryland electric utility. Therefore, the majority of the reductions are in the PJM-SW zone, with smaller amounts in the PJM-MidE and PJM-APS zones. Load adjustments are made in proportion to the relevant utility load shares in those zones. Figure 10.1, below, shows the LTER Reference Case load compared to the EE load for the PJM-SW zone and Figure 10.2, below, shows the impact on peak demand. The EE load in PJM-SW is reduced by about 5.5 million MWh or about 7 percent, and peak demand is reduced by 1,000 MW or about 6 percent, in 2030.

The impact on loads in PJM-MidE and PJM-APS are minimal (less than 1 percent difference in 2030). The reason why the PJM-MidE and PJM-APS load reductions are small relative to PJM-SW is that the Maryland portion of the total load for these zones is small compared to Maryland's share of the total load in PJM-SW.

In the LTER Reference Case, the magnitude of energy efficiency and conservation savings associated with EmPOWER Maryland represents achievement of 100 percent of the demand (MW) reduction goals and about 60 percent of the energy reduction goals.[21] The aggressive energy efficiency scenarios addressed in this Chapter are predicated on the assumption that Maryland's energy reduction goal established in the EmPOWER Maryland legislation will be fully achieved by 2020 and demand reductions equal to 150 percent of the demand reduction target would be achieved by 2030. The programs in place in other states are unaffected.

[21] Based on the most recent utility EmPOWER Maryland filings (Spring of 2011), 60 percent achievement of the energy reduction goals may be optimistic. The utilities indicate program uptake has slowed considerably since 2010 due to the economic environment.

Figure 10.1 PJM-SW Loads

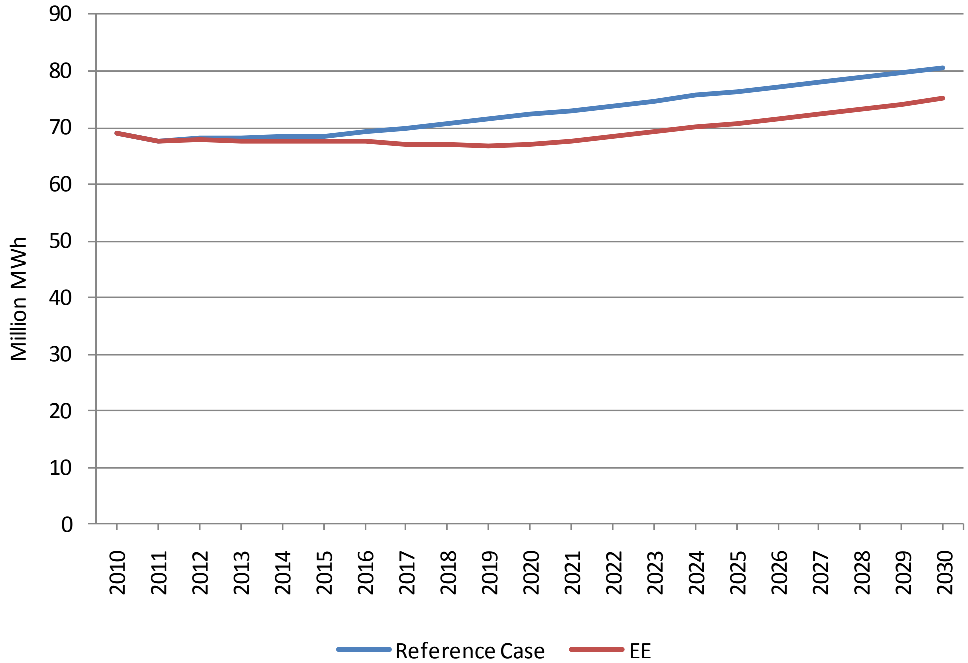
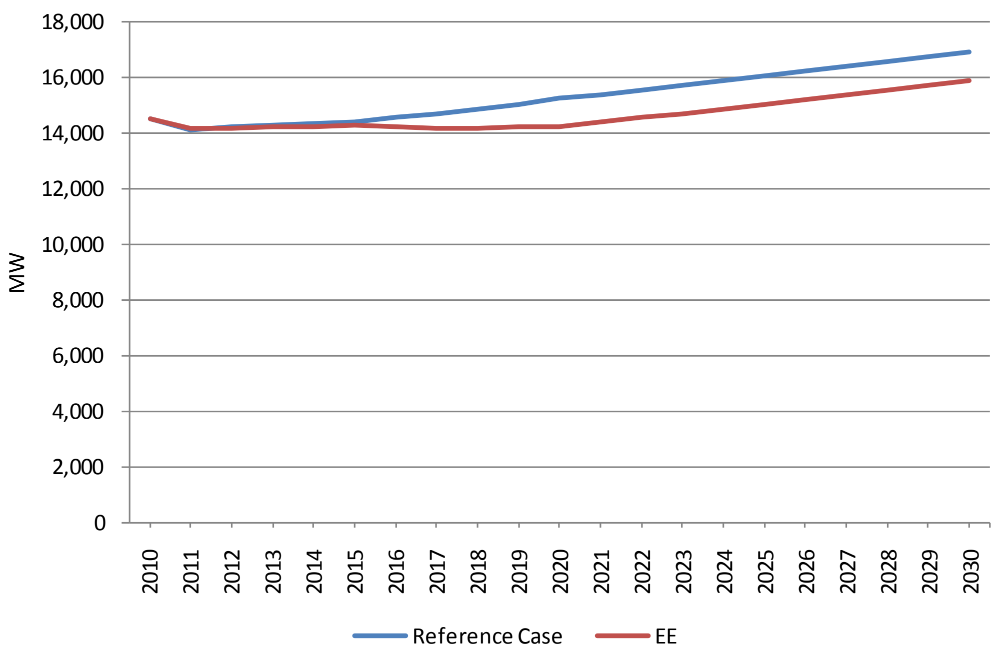


Figure 10.2 PJM-SW Peak Demand

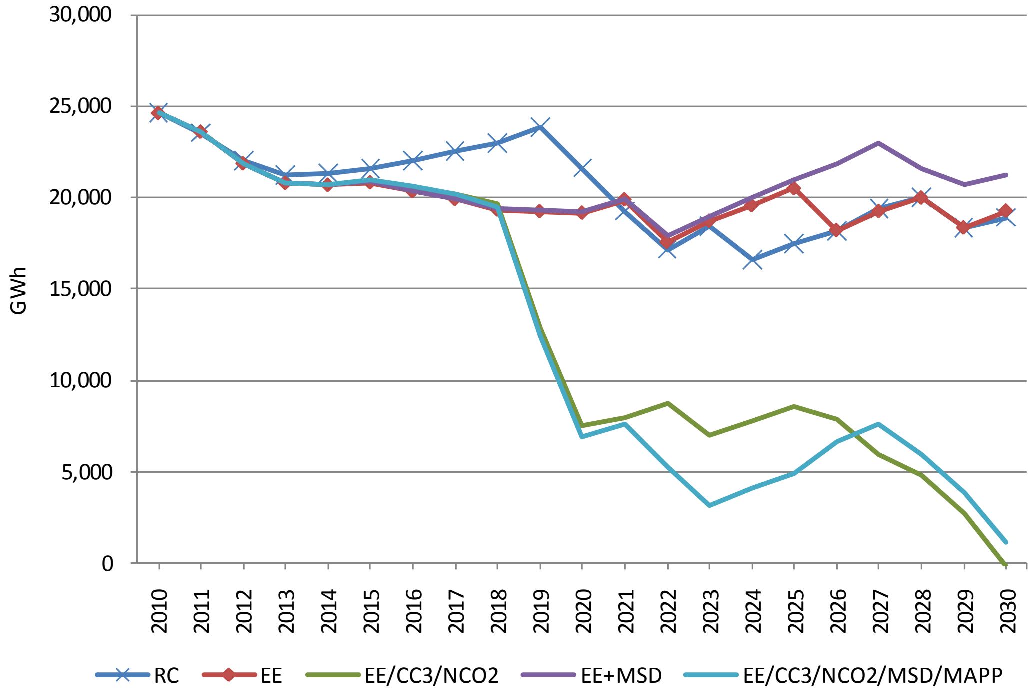


As seen in both Figure 10.1 and Figure 10.2, the total reduction in energy consumption and peak demand associated with more aggressive energy efficiency and conservation programs in Maryland is relatively modest compared to total energy consumption and peak demand in PJM-SW. Similar graphs for PJM-APS and PJM-MidE would show a much smaller differential than shown in for PJM-SW.

10.2 Net Imports

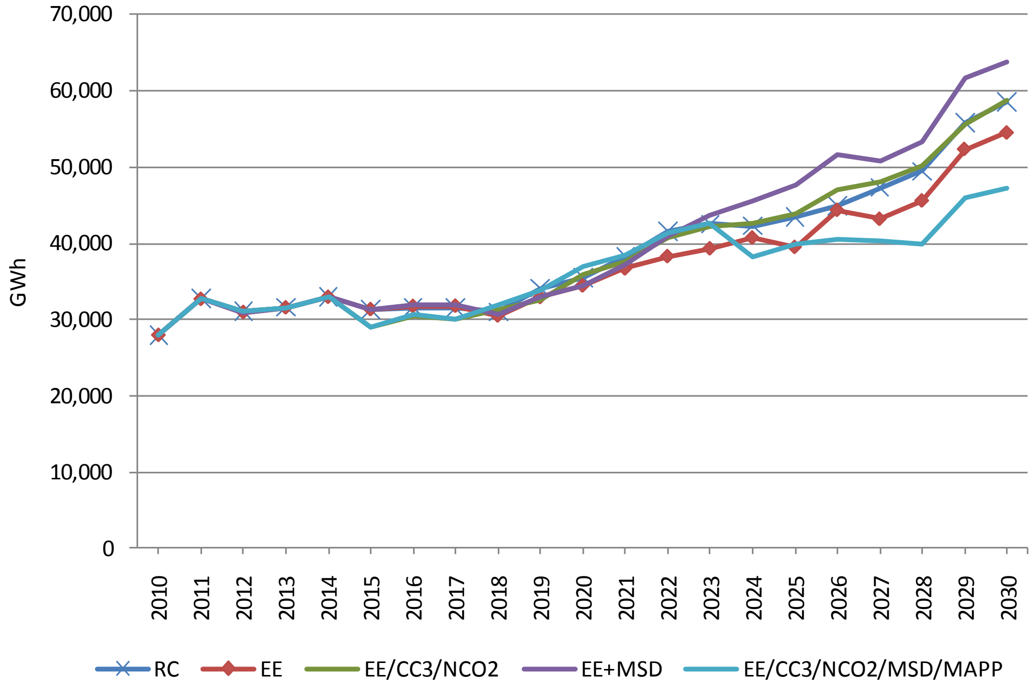
The increased energy efficiency in Maryland reduces load but has little effect on net imports into PJM-SW. Figure 10.3, below, shows the net imports into PJM-SW under the EE scenarios. As Figure 10.3 shows, there is little difference in net imports under the LTER Reference Case and the EE scenario. Net imports are, however, strongly affected by infrastructure changes and the implementation of national carbon legislation. More aggressive energy efficiency and conservation policies, however, do have an effect on the impacts on net imports associated with the infrastructure changes. Net imports to PJM-SW are slightly higher in the MSD scenario compared to EE+MSD and net imports drop to zero when Calvert Cliffs 3 and national carbon legislation are included. Under the non-EE scenarios, PJM-SW has positive net imports of approximately 5,000 GWh in 2030 for CC3+NCO2 alone and about 7,000 GWh for CC3/NCO2/MDS/MAPP. Net imports of these magnitudes are relatively small.

Figure 10.3 PJM-SW Net Imports



For PJM-MidE, net imports increase under all of the aggressive energy efficiency scenarios. In the EE+MSD scenario, net imports into PJM-MidE are slightly higher than in the LTER Reference Case (see Figure 10.4 below) as reduced energy use in PJM-SW allows an increase in transfers into PJM-MidE, facilitated by the increase in transmission capacity from the Mt. Storm to Doubs transmission line (under MSD alone, net imports are decreased slightly relative to the LTER Reference Case).

Figure 10.4 PJM-MidE Net Imports Under Aggressive Energy Efficiency Scenarios



Exports from PJM-APS are unaffected by the increased energy efficiency in PJM-SW, as the power flows into PJM-MidE instead. As with PJM-SW, the infrastructure changes dominate the impacts on net imports relative to the effect of more aggressive energy efficiency.

10.3 Capacity Additions and Retirements

For all of the high energy efficiency scenarios, planned capacity additions and age-based plant retirements are unchanged from the LTER Reference Case since these values are assumed. The reduction in load in the high energy efficiency scenarios is small in relation to the overall PJM load, and therefore the effect on RPS-related renewable energy builds is minimal. Renewable energy builds in Maryland are unaffected as Maryland sources a major portion of RPS-related generation from out-of-state resources.

Economic retirements are dominated by infrastructure and carbon legislation effects; hence, for all aggressive energy efficiency scenarios, economic retirements and retrofits are almost identical to the scenarios based on LTER Reference Case levels of energy efficiency and conservation. There are two small changes initiated by the addition of aggressive energy efficiency in PJM-SW: an additional 207 MW retires in PJM-AEP in the EE/CC3/NCO2 scenarios, and an additional 420 MW retires in the Cincinnati zone in the EE/CC3/NCO2/MSD/MAPP scenario versus the analogous alternative scenarios that are based on LTER Reference Case levels of energy efficiency and conservation.

The total MW amount of natural gas-fired capacity added in PJM-SW is affected by more aggressive energy efficiency, as shown in Table 10.1 below. In the LTER Reference Case, PJM-SW builds 2,385 MW of new natural gas capacity, and in the high energy efficiency scenario this capacity is reduced to 1,431 MW. For the other high energy efficiency scenarios, infrastructure and carbon legislation effects dominate and the natural gas capacity builds are the same as the respective scenarios that are based on LTER Reference Case levels of energy efficiency/conservation, with net imports being adjusted for changes in load. For example, in the EE+MSD and the MSD alone scenarios, the same amount of capacity is added in PJM-SW, with imports making up the difference in load growth. Capacity additions in PJM-APS are unaffected by more aggressive energy efficiency/conservation, with infrastructure changes and carbon legislation accounting for the differences shown in Table 10.1.

Table 10.1
Cumulative Natural Gas Capacity Additions Through 2030 (MW)

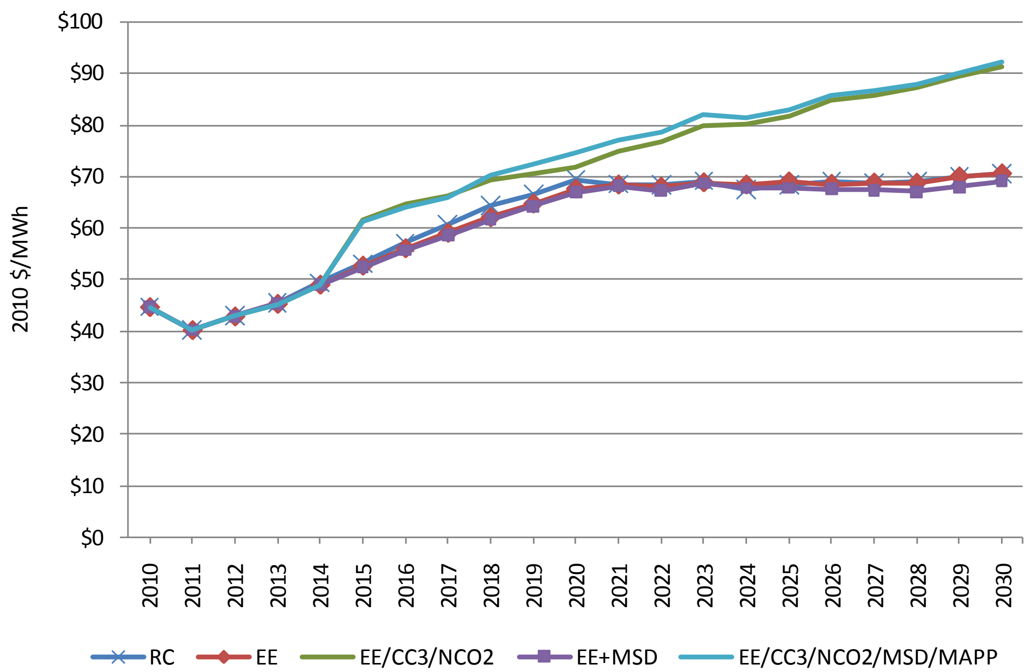
Scenario	PJM-SW	PJM-MidE	PJM-APS	PJM Total
RC	2,385	1,908	3,816	30,101
EE	1,431	2,385	3,816	28,193
EE+MSD	1,431	477	4,770	27,845
MSD	1,431	3,816	4,770	30,145
EE/CC3/NCO2	2,862	1,431	3,816	33,971
EE/CC3/NCO2/MSD/MAPP	2,385	4,293	3,816	33,753

Capacity additions are, however, strongly affected in PJM-MidE. In the high energy efficiency/conservation scenario, PJM-MidE capacity additions increase by 477 MW (one combined cycle plant) compared to the LTER Reference Case. This difference is because fewer plants are built in PJM-SW under the high energy efficiency scenario and therefore less energy is available for import into PJM-MidE from PJM-SW. In the EE+MSD scenario, generic plant additions drop to 477 MW as load growth in PJM-MidE is met in large part through increased imports facilitated by the increased transfer capacity of the Mt. Storm to Doubs transmission line. In the MSD alone scenario, PJM-MidE adds almost 4,000 MW in total by 2030, and the additional load growth in PJM-SW (as compared to the high energy efficiency scenario) is met by imports from PJM-APS which are unavailable to PJM-MidE. PJM-MidE also builds slightly less capacity in the EE/CC3/NCO2 and EE/CC3/NCO2/MSD/MAPP scenarios than in the non-EE versions due to the reduced opportunity to import energy. In these cases also, the infrastructure and carbon legislation effects dominate the energy efficiency impacts.

10.4 Energy Prices

Wholesale energy prices are only marginally affected by the implementation of more aggressive energy efficiency/conservation policies in Maryland. Figure 10.5, below, shows that in real terms, energy prices in PJM-SW are almost identical under the LTER Reference Case and the EE scenario. The major differentials in wholesale prices shown in Figure 10.5 are due to infrastructure changes (Calvert Cliff 3, the Mt. Storm to Doubs transmission line, and the MAPP transmission line) and carbon legislation. Wholesale energy prices in PJM-MidE and PJM-APS are unaffected by the implementation of aggressive energy efficiency and conservation policies in Maryland.

Figure 10.5 PJM-SW Real All-Hours Energy Prices

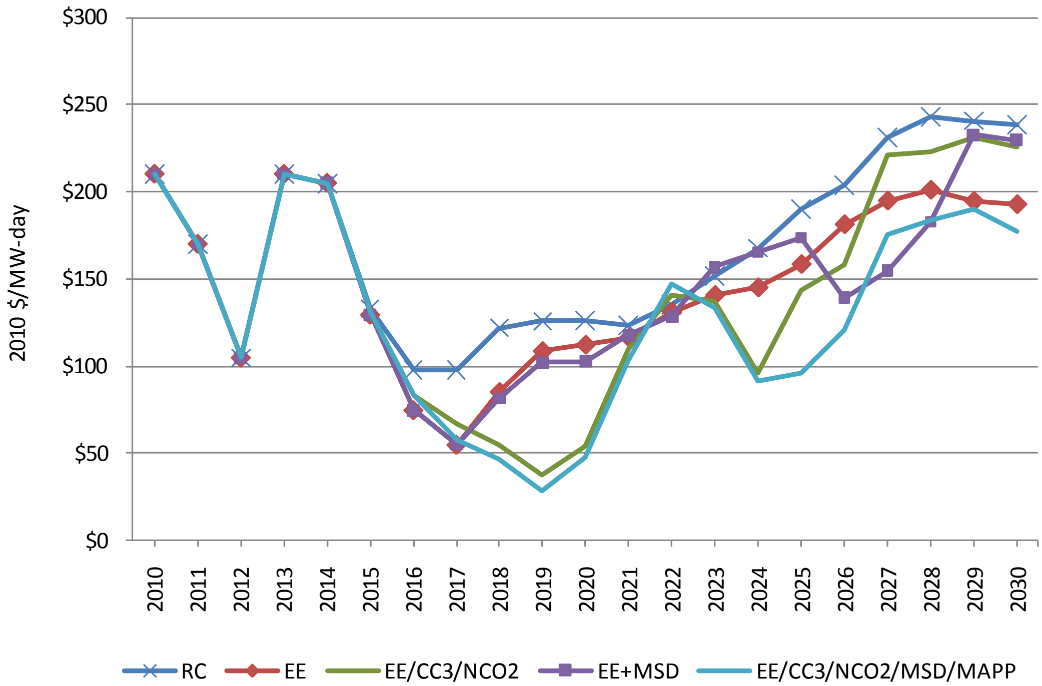


10.5 Capacity Prices

As shown in Figure 10.6 below, the LTER Reference Case modified for aggressive energy efficiency/conservation shows a consistent and sustained difference in capacity prices for PJM-SW. By 2030, this difference is estimated to be approximately $50 per MW-day. The other alternative scenarios that include an aggressive energy efficiency/conservation component

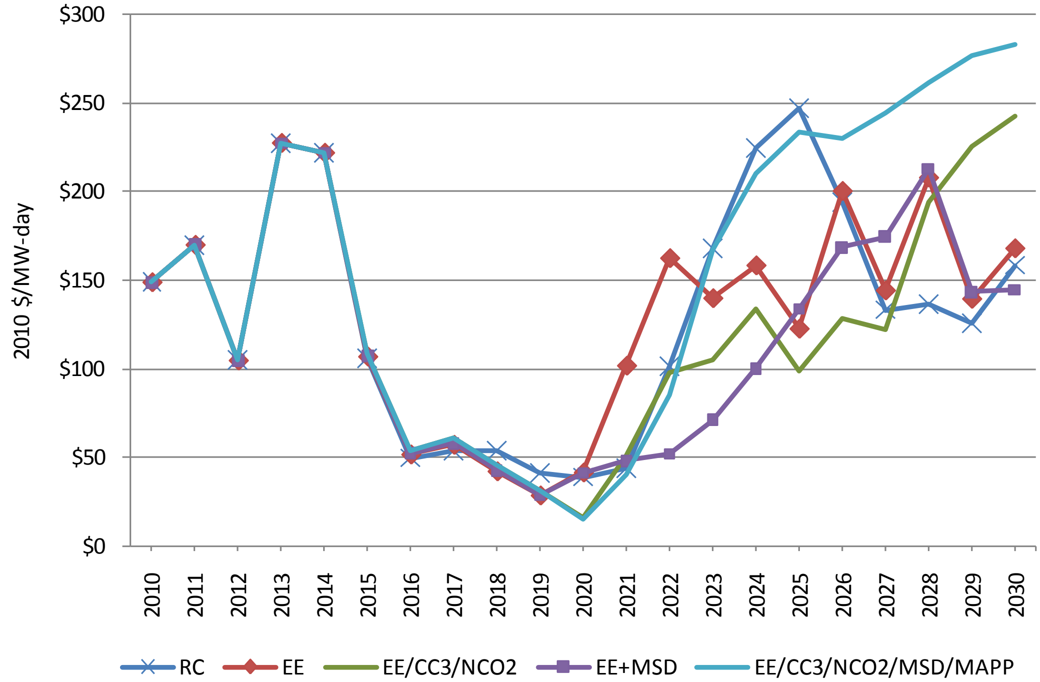
(EE+MSD and EE/CC3/NCO2) also indicate reductions in capacity prices relative to the LTER Reference Case. By 2030, however, there is a greater degree of convergence between the high energy efficiency cases that include an infrastructure component and the LTER Reference Case.

Figure 10.6 PJM-SW Capacity Prices



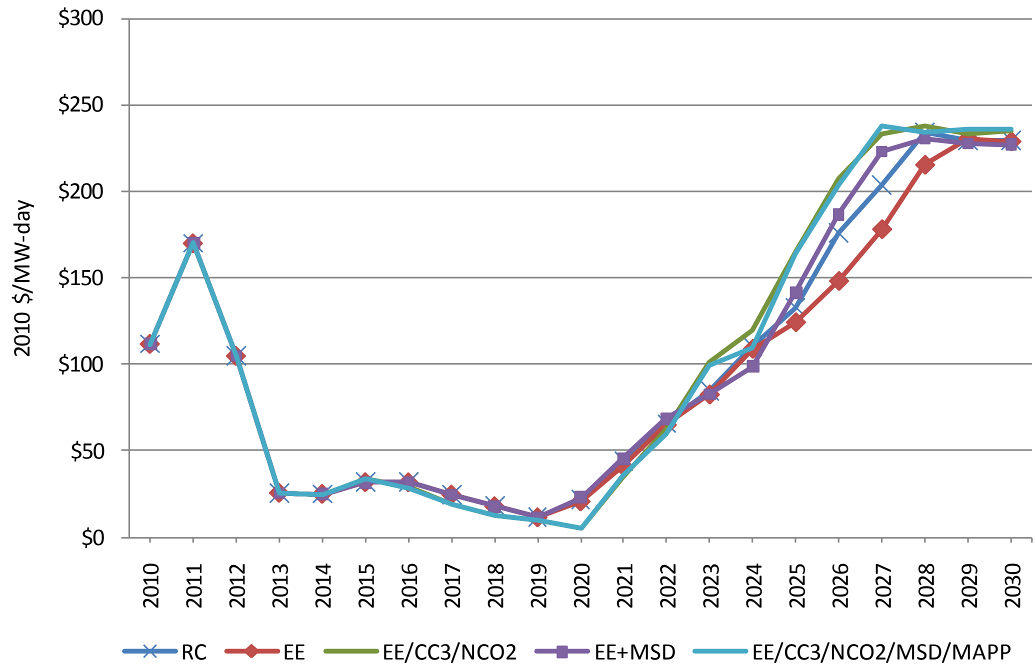
Capacity prices in PJM-MidE, shown in Figure 10.7 below, exhibit the same general instability that has characterized other scenario analyses, and there is no systematic and sustained relationship between capacity prices under the LTER Reference Case and any of the scenarios that include an aggressive energy efficiency/conservation component.

Figure 10.7 PJM-MidE Capacity Prices



Capacity prices in PJM-APS do not show the same magnitude of deviation from the LTER Reference Case as was estimated for PJM-SW (see Figure 10.8 below). This lack of deviation is largely due to the much lower relative impact of aggressive energy efficiency and conservation initiatives relative to total load in the zone given that Maryland accounts for a relatively smaller portion of the zonal load. By 2030, the difference in capacity prices for the LTER Reference Case and the high energy efficiency/conservation case is negligible.

Figure 10.8 PJM-APS Capacity Prices



The capacity prices shown for the aggressive energy efficiency cases that include an infrastructure modification component tend to be slightly higher than the LTER Reference Case, due principally to the impacts associated with net imports.

These capacity price results, combined with the results obtained from the energy price simulations, suggest that the implementation of aggressive energy efficiency and conservation programs in Maryland can be expected to generate power supply cost savings to consumers from three sources: (1) reduced capacity prices (particularly in PJM-SW), which will entail a modestly lower capacity price component to electric billings; (2) lower total demand, which on average would lower the peak demand and hence demand-related charges; and (3) lower energy consumption on average, which would lower the number of billing units (MWh) to applicable energy-related charges. No appreciable savings is available from lower energy prices since energy prices are shown to be largely unaffected by the implementation of more aggressive energy efficiency and conservation policies in Maryland.

10.6 Emissions

The 2030 emissions for each scenario for NO_x, SO_2, and CO_2 are summarized in Table 10.2 below. For Maryland plants subject to Healthy Air Act ("HAA") restrictions, SO_2 and NO_x emissions are nearly unchanged relative to the LTER Reference Case since it is still economical for these units to run at maximum capacity. Total NO_x emissions are lower in 2030 in the high energy efficiency/conservation case as compared to the LTER Reference Case due to fewer natural gas plant additions in the high energy efficiency case because of slightly lower demand.

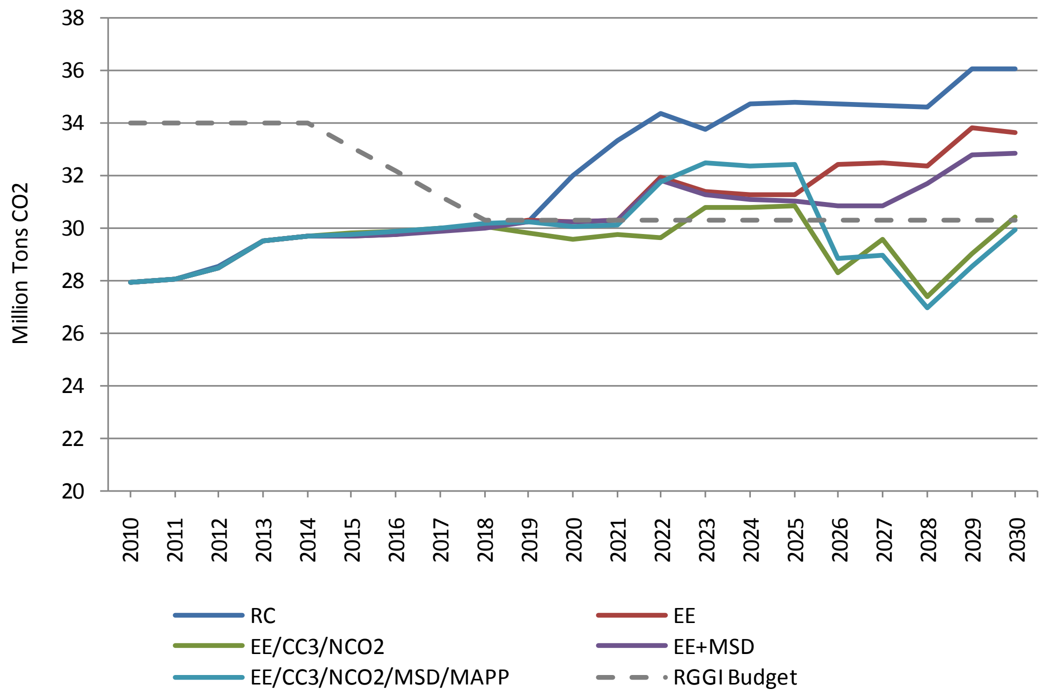
Table 10.2
Aggressive Energy Efficiency/Conservation Alternative Scenario Emissions (Tons)

Year	Scenario	HAA SO_2	HAA NO_x	Total NO_x	Total CO_2
2010	All	22,154	13,717	16,815	27,962,352
	RC	33,508	14,185	17,223	36,054,438
	EE	33,494	14,187	16,627	33,654,515
2030	EE+MSD	33,334	14,160	16,400	32,828,549
	EE/CC3/NCO2	33,348	13,939	17,336	30,419,740
	EE/CC3/NCO2/MSD/MAPP	33,362	13,946	17,215	29,918,285
HAA Caps & RGGI Budget		36,467	16,324	--	30,288,482

This result applies to in-State Maryland CO_2 emissions as well, which are below the LTER Reference Case results for all the high energy efficiency cases (see Figure 10.9 below). However, only the EE/CC3/NCO2/MSD/MAPP scenario is below Maryland's Regional

Greenhouse Gas Initiative ("RGGI") CO_2 budget in 2030 due mainly to the implementation of national carbon legislation.

Figure 10.9 Maryland CO_2 Emissions for the Aggressive Energy Efficiency Scenarios



10.7 Results

The principal results from the analysis in this Chapter are:

- The high EE assumptions entail reduction in energy usage of 7.7 percent (5.5 million MWh) in PJM-SW by 2030 relative to the LTER Reference Case and 6.0 percent (1,000 MW) in PJM-SW peak demand. Reduced energy consumption and peak demand will result in reduced cost to consumers, other factors held constant.
- Net imports into PJM-SW under the high EE assumptions are below those of the LTER Reference Case for the period 2013 to 2020 and approximately equivalent to imports under the LTER Reference Case assumptions for the remainder of the study period.

- Under the EE assumptions, PJM constructs approximately 28,200 MW of new natural gas capacity by 2030, which is 1,900 MW less than under the LTER Reference Case assumptions.
- New natural gas capacity additions under the EE assumptions are approximately 1,000 MW lower in PJM-SW, about 500 MW higher in PJM-MidE, and unchanged in PJM-APS compared to the LTER Reference Case capacity additions (cumulative between 2010 and 2030).
- Energy prices in any of the three zones that include portions of Maryland are not significantly affected by the high EE assumptions relative to the LTER Reference Case.
- Capacity prices under the EE assumptions are below the LTER Reference Case capacity prices in PJM-SW for all years after 2015 and below the LTER Reference Case capacity prices in PJM-APS intermittently during the last eight years of the study period.
- Capacity prices in PJM-MidE are more unstable than the capacity prices in the other two zones that contain portions of Maryland. Following 2020, there is no stable relationship between the LTER Reference Case capacity prices and capacity prices under the high EE scenarios.
- Emissions of CO_2 in Maryland under the high EE scenarios are below the LTER Reference Case emissions in all years after 2019. Only under the EE/CC3/NCO2/MSD/MAPP scenario are the in-State CO_2 emissions under the RGGI budget in 2030.

11. CLIMATE CHANGE ALTERNATIVE SCENARIOS

11.1 Introduction

The Climate Change scenarios are designed to gauge the impact of alternative weather conditions on loads, energy prices, emissions, and other issues related to electricity usage in Maryland. In this scenario, it was assumed that average ambient temperature would be higher by 2.3 degrees Fahrenheit by 2030 compared to long-term normal weather conditions. The yearly climate change was linearly interpolated between 2010 and 2030. The alternative scenarios analyzed were Climate Change alone ("CC") and climate change with the construction and operation of Calvert Cliffs 3, implementation of national carbon legislation, construction of the Mt. Storm to Doubs transmission line, and construction of the Mid-Atlantic Power Pathway transmission project ("CC/CC3/NCO2/MSD/MAPP").

11.2 Energy and Demand

The total annual energy use in PJM is only marginally affected by the introduction of climate change. In the LTER Reference Case, the average annual energy growth rate is approximately 0.92 percent, and increases only slightly to 0.98 percent under the Climate Change scenario. The temperature change leads to both warmer summers and winters; therefore, although more energy is used in the summer, less energy is used in the winter, leaving the overall annual average relatively unchanged.

Although the average annual growth rate for energy remains relatively unchanged, the increase in temperature results in higher peaks leading to a significant increase in PJM peak demand. Over the study period, the average annual growth rate for PJM peak demand under the

LTER Reference Case is approximately 0.87 percent, while in the Climate Change scenario the rate is about 1.08 percent.

11.3 Capacity Additions

The higher peak demands occurring in the Climate Change scenario affect the timing, magnitude, and composition of capacity additions. Figure 11.1, below, shows the incremental capacity additions for the LTER Reference Case and Figure 11.2, also below, shows the incremental capacity additions for the Climate Change scenario. Under the Climate Change scenario, an additional 8,590 MW of new natural gas capacity is built in PJM as a whole compared to the LTER Reference Case. The builds also begin earlier in response to a need for increased generation to maintain reliability in light of higher peak demand. Of the new natural gas additions, more are comprised of combustion turbines, with about 13.6 percent of all new additions between 2010 and 2030 comprised of combustion turbines in the Climate Change scenario, compared to about 4.7 percent in the LTER Reference Case.

Figure 11.1 LTER Reference Case: Incremental Generation Additions in PJM

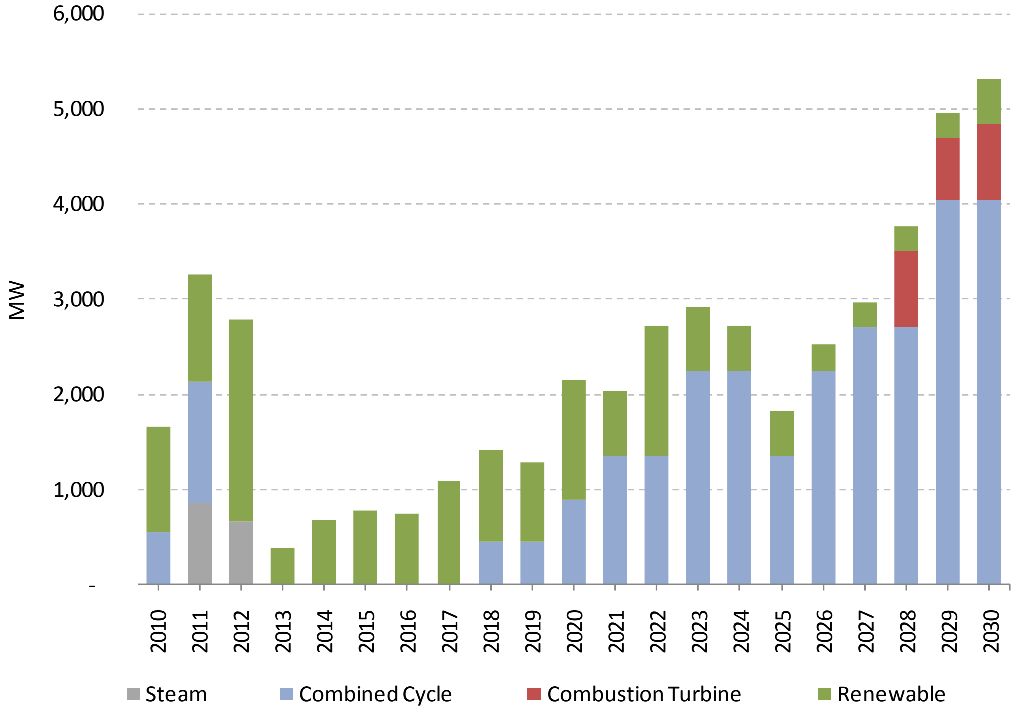
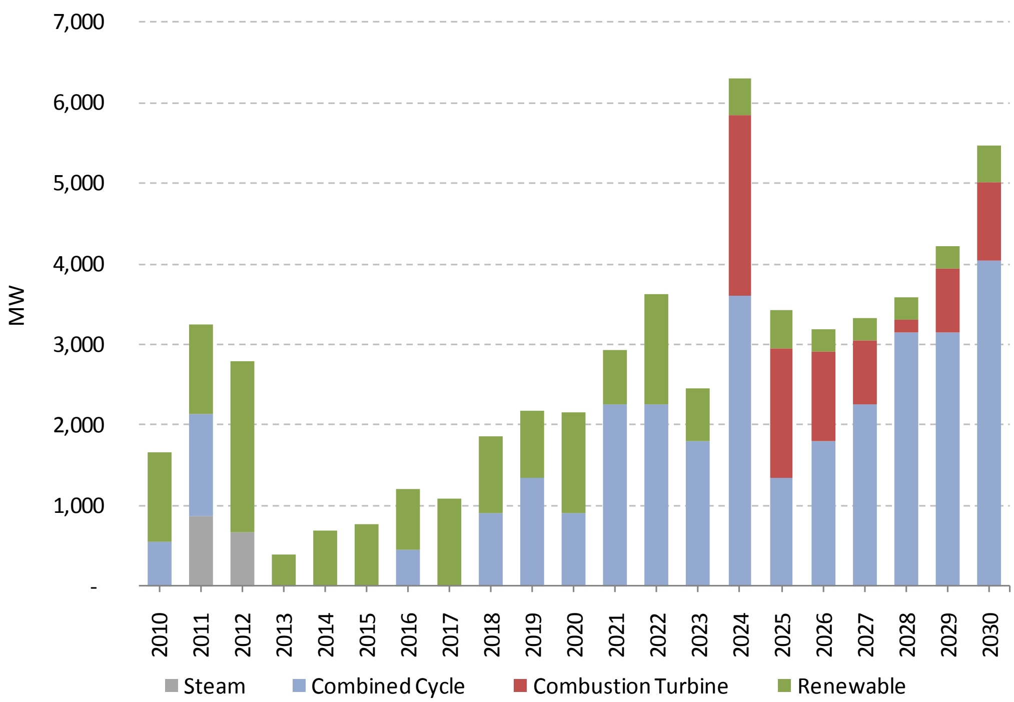


Figure 11.2 Climate Change: Incremental Generation Additions in PJM



11.4 Fuel Use

Maryland coal usage in the Climate Change scenario is unaffected as coal plants are still the most economical units (see Figure 11.3 below). Under CC/CC3/NCO2/MSD/MAPP, the national carbon price effect dominates. Natural gas usage increases in both the Climate Change scenario and the CC/CC3/NCO2/MSD/MAPP scenario compared to the LTER Reference Case (see Figure 11.4 below). Natural gas usage is also higher in the CC/CC3/NCO2/MSD/MAPP scenario compared to the CC3/NCO2/MSD/MAPP scenario as additional natural gas generation is built to accommodate the increased peak demand.

Figure 11.3 Coal Use for Electricity Generation in Maryland

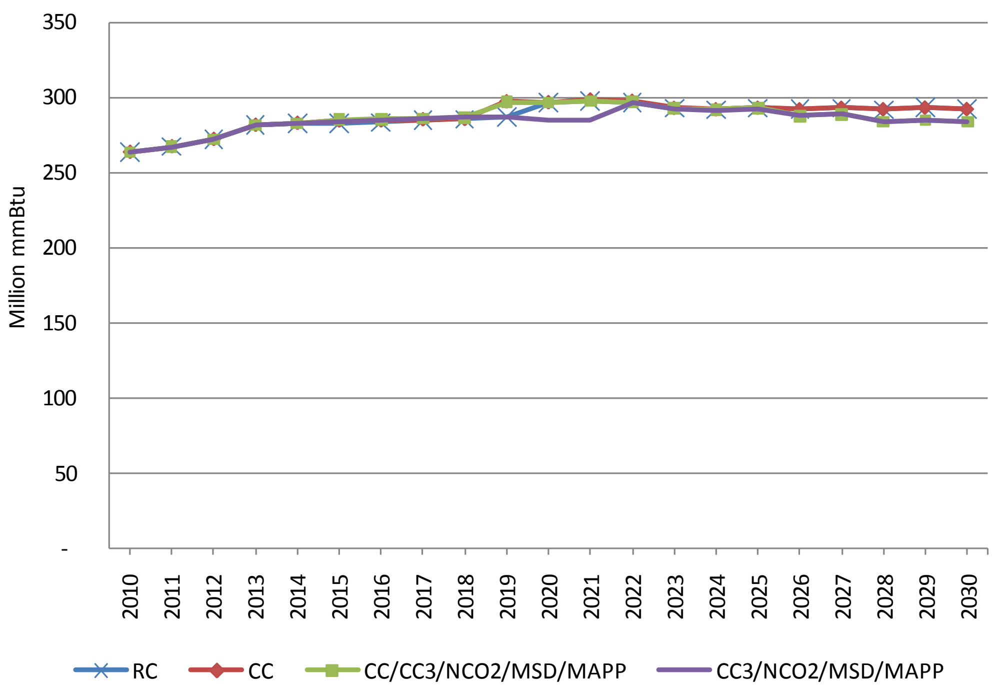
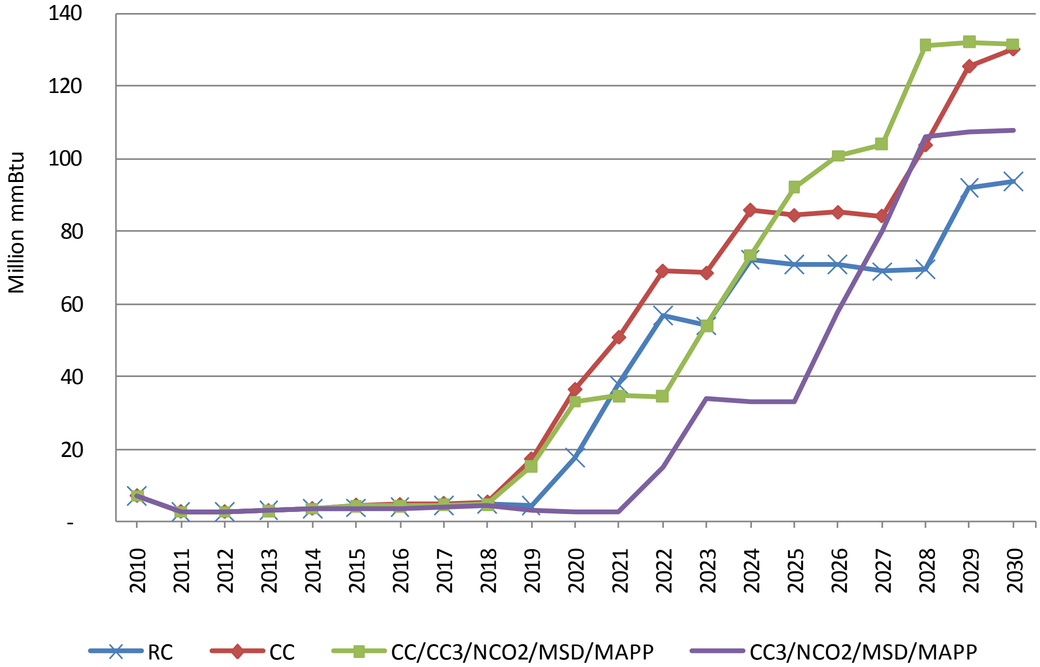


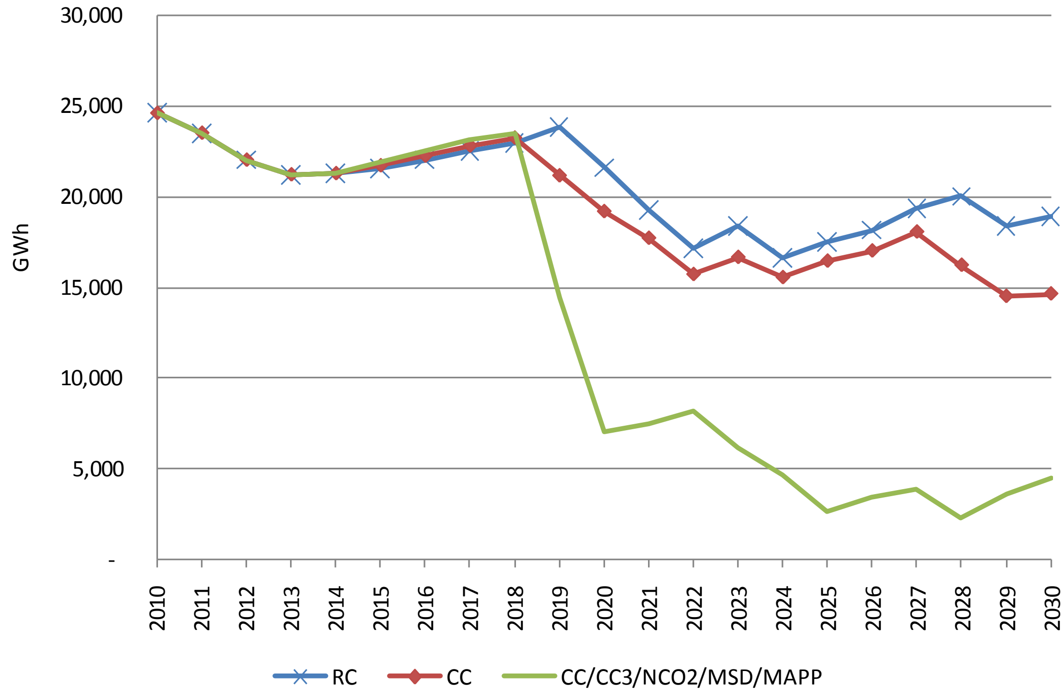
Figure 11.4 Natural Gas Use for Electricity Generation in Maryland



11.5 Net Imports

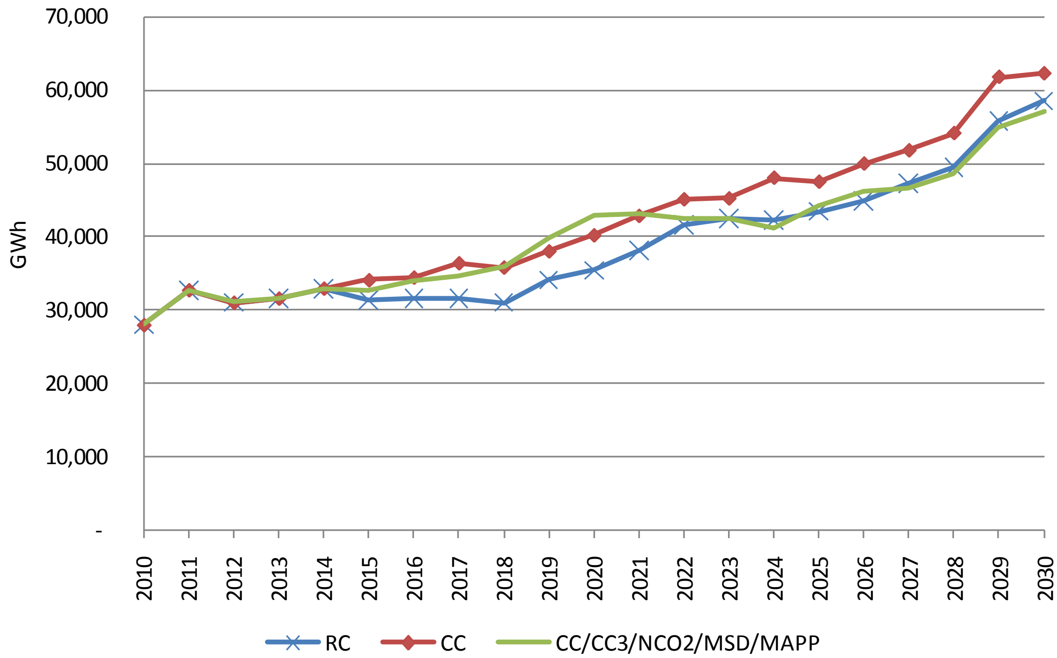
Net imports are affected by the change in temperature, with the Climate Change scenario showing a slight increase in net imports in PJM-SW (see Figure 11.5 below), due to the increased need for peaking energy. Net imports under CC/CC3/NCO2/MSD/MAPP are dominated by the carbon price effect and drop to minimal levels as new natural gas capacity begins to come on-line.

Figure 11.5 PJM-SW Net Imports



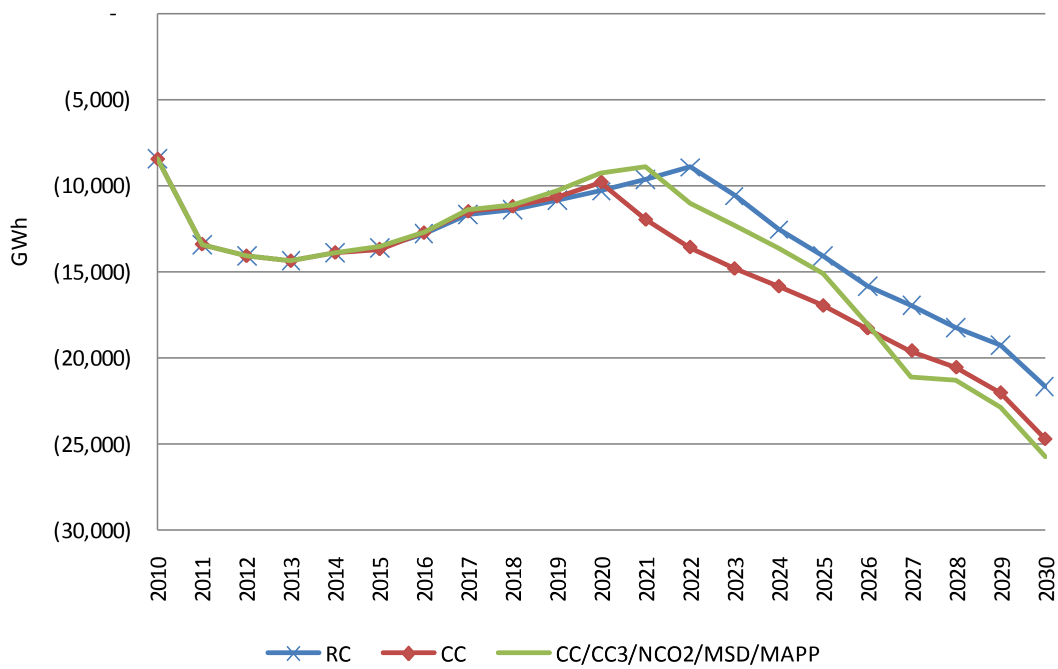
Net imports in PJM-MidE are relatively unaffected by the climate change as imports remain the most economical source of supply in this zone (see Figure 11.6 below). Net imports are consistently slightly higher in the CC scenario compared to the LTER Reference Case due to the slight increase in demand.

Figure 11.6 PJM-MidE Net Imports



PJM-APS remains an energy exporter, with total exports increasing under the CC scenario compared to the LTER Reference Case due to increased demand for energy in PJM-SW and PJM-MidE.

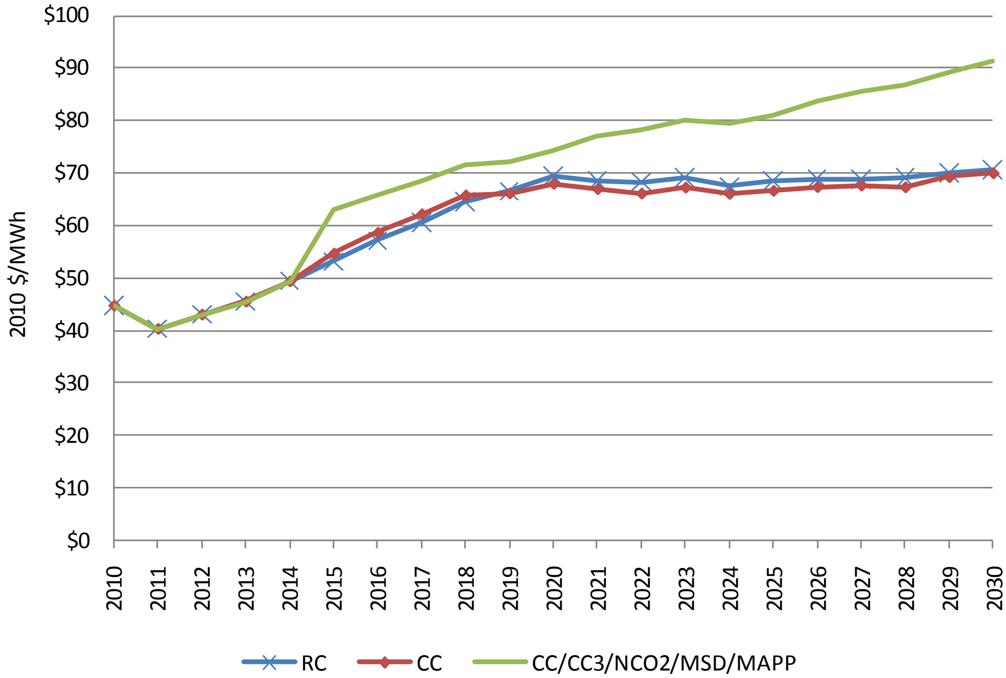
Figure 11.7 PJM-APS Net Imports



11.6 Energy Prices

Figure 11.8, below, shows the real energy prices for PJM-SW. Energy prices in the long-run are relatively unaffected by the temperature change. Energy prices in PJM-SW are slightly lower under the CC scenario after new natural gas generation starts to come on-line, but they converge to the LTER Reference Case by 2030. Energy prices in PJM-SW under the CC/CC3/NCO2/MSD/MAPP scenario are dominated by the carbon price effect.

Figure 11.8 PJM-SW Real All-Hours Energy Price



PJM-MidE (see Figure 11.9 below) and PJM-APS (see Figure 11.10 below) show the same energy price pattern.

Figure 11.9 PJM-MidE Real All-Hours Energy Price

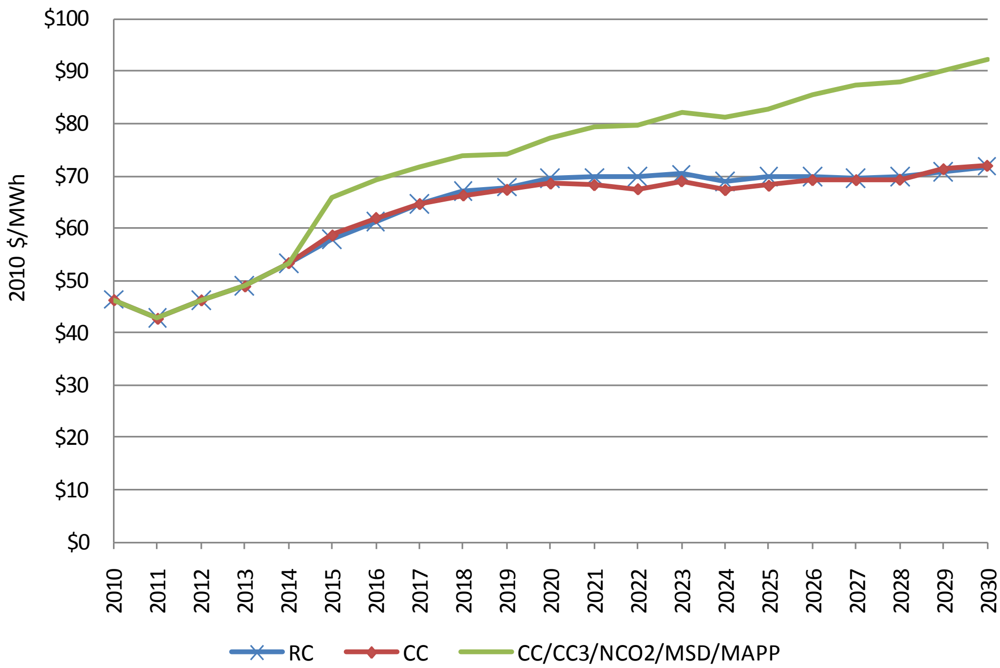
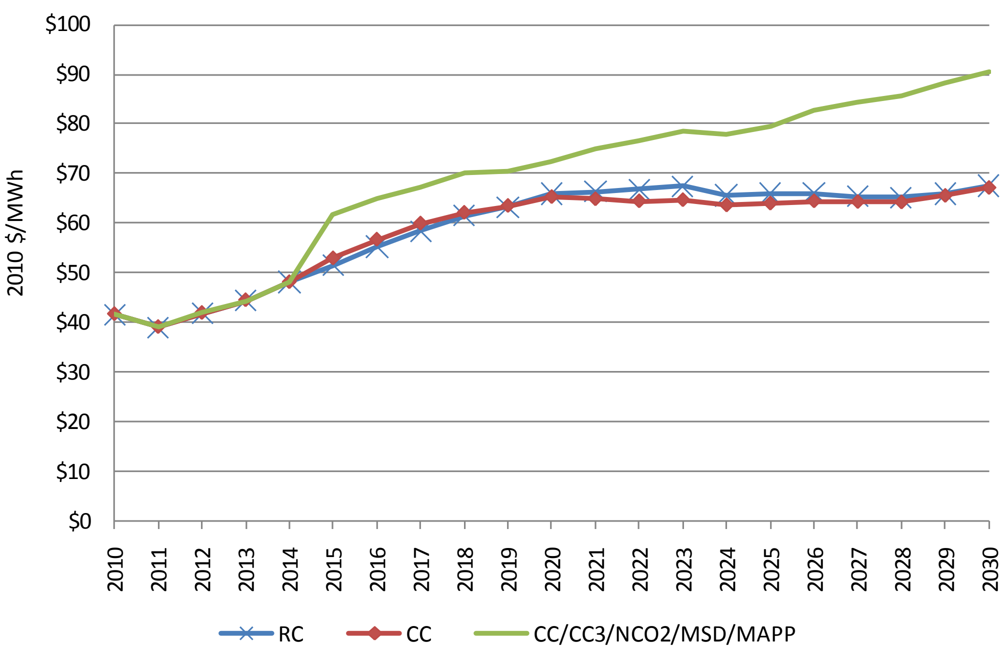


Figure 11.10 PJM-APS Real All-Hours Energy Price



11.7 Capacity Prices

Capacity prices in PJM-SW are consistently higher in the climate change scenarios until the last five years of the study period (see Figure 11.11 below), compared to the LTER Reference Case. This is due to the higher peak demand levels in the climate change cases relative to the LTER Reference Case, which requires that more natural gas capacity is built and begun earlier. Capacity prices in PJM-MidE (see Figure 11.12 below) and PJM-APS (see Figure 11.13 below) are also consistently higher in the climate change scenarios compared to the LTER Reference Case, with PJM-MidE exhibiting the volatility characteristic of this zone. PJM-APS capacity prices begin to converge in the last five years of the study period.

Figure 11.11 PJM-SW Capacity Price

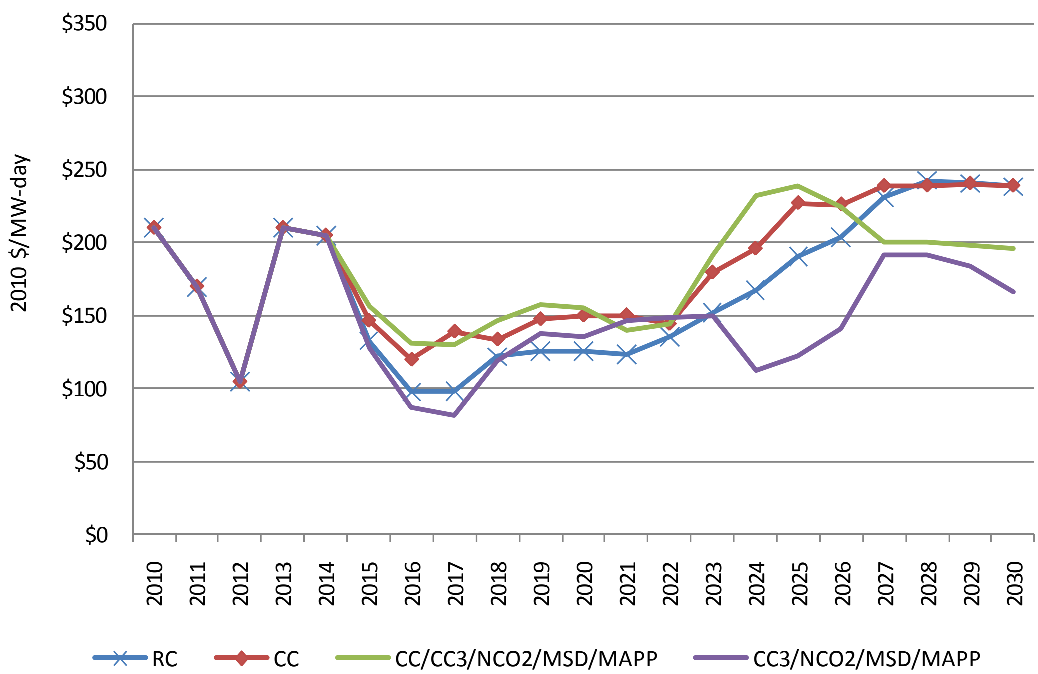


Figure 11.12 PJM-MidE Capacity Price

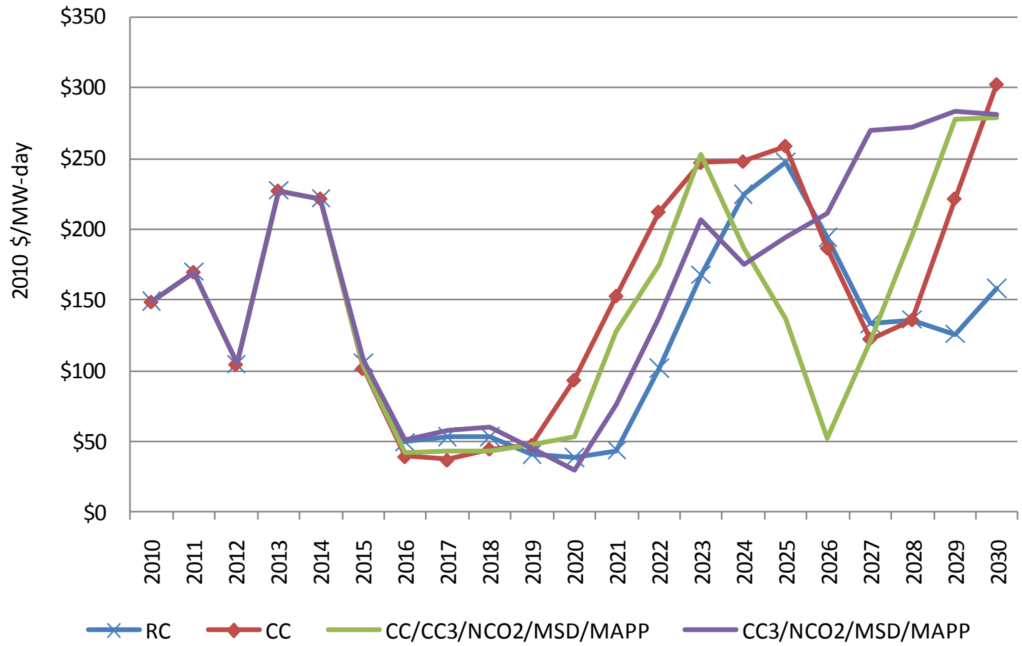
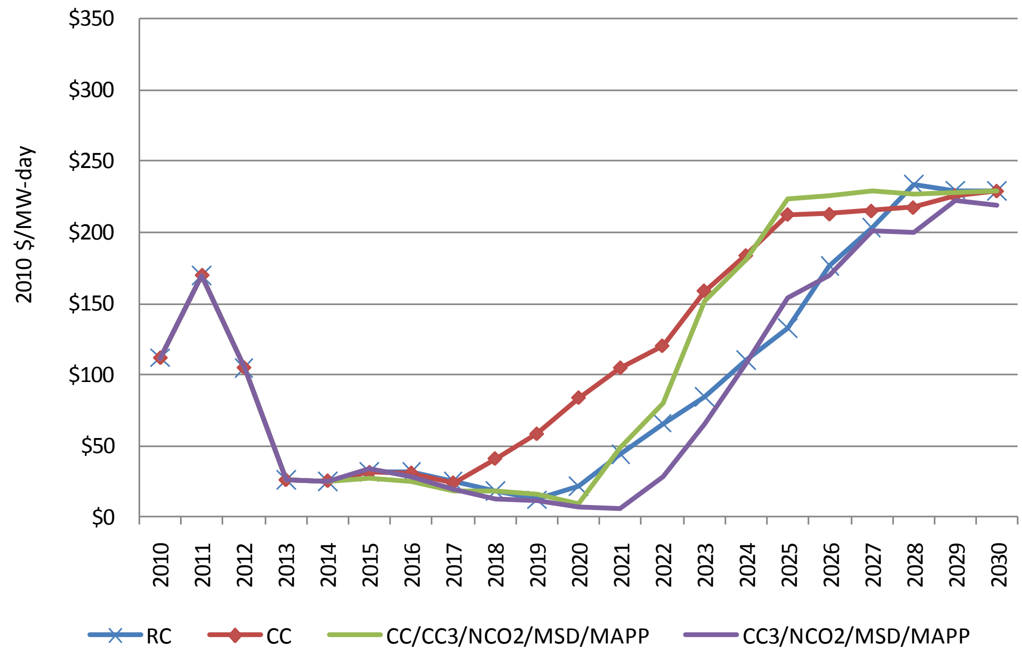


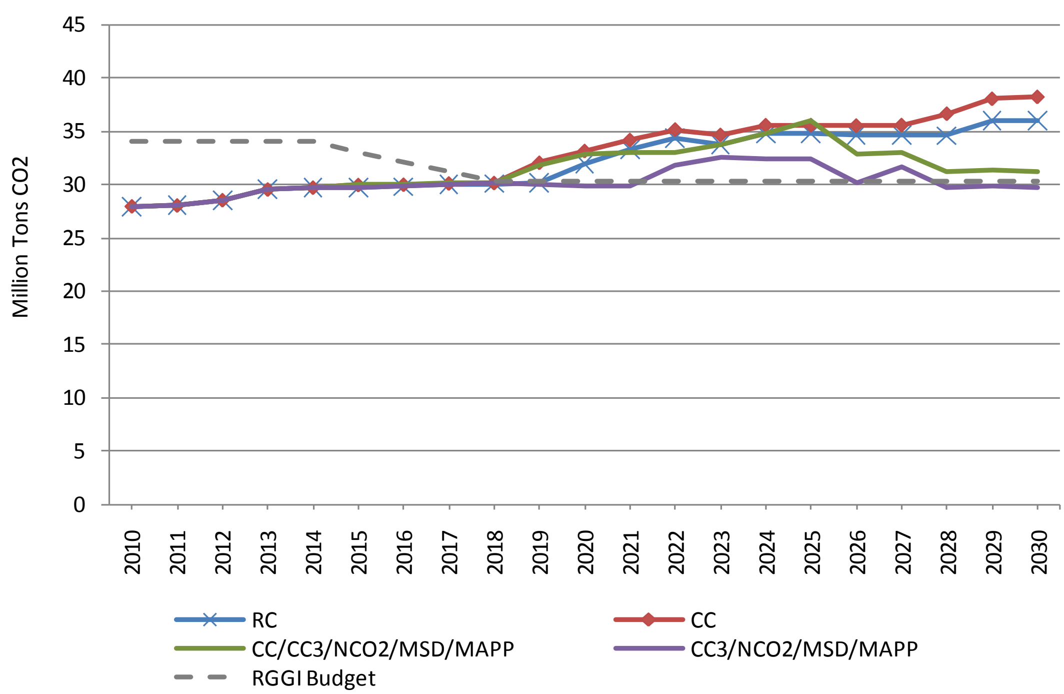
Figure 11.13 PJM-APS Capacity Price



11.8 Emissions

Maryland plants subject to the Healthy Air Act (HAA) are not affected under the Climate Change scenario, relative to the LTER Reference Case. Under the CC/CC3/NCO2/MSD/MAPP scenario, emissions are down slightly due to carbon price effects. Figure 11.14, below, shows the total Maryland CO_2 emissions for the Climate Change scenarios. Total CO_2 emissions increase in the Climate Change scenario relative to the LTER Reference Case as more natural gas generation is built. Under the CC/CC3/NCO2/MSD/MAPP scenario, total CO_2 emissions are slightly higher than the same scenario without Climate Change due to the additional natural gas generation that is required to meet the increased peak demand. None of the Climate Change Scenarios result in CO_2 emissions that are under the Maryland Regional Greenhouse Gas Initiative budget.

Figure 11.14 Total Maryland CO_2 Emissions



11.9 Results

The primary results from the analysis in this chapter are:

- The scenarios that are adjusted for climate change result in an additional 8,590 MW of new natural gas capacity being built in PJM compared to the LTER Reference Case. Additionally, a larger share of the new natural gas capacity is in the form of peaking plants.
- The addition of climate change has an insignificant impact on coal use for electricity generation in Maryland; natural gas use, however, is higher than in the LTER Reference Case.
- Net imports in PJM-SW are higher for the climate change scenario compared to the LTER Reference Case and fall to very low levels in the climate change scenario that includes CC3/NCO2/MSD/MAPP.
- Net imports in PJM-MidE are slightly higher than the LTER Reference Case in the climate change scenario, and exports are slightly higher for PJM-APS.
- Real energy prices for all three zones that include Maryland are marginally lower through the early to mid-2020's in the climate change scenario, but they converge to the long-run LTER Reference Case result by 2030.
- Capacity prices under the climate change scenario are consistently higher than in the LTER Reference Case for all three Maryland-relevant zones from 2016/2017 through about 2028. Capacity prices for PJM-SW and PJM-APS converge to the LTER Reference Case prices in the last three years of the study period. Capacity prices in PJM-MidE are volatile in the last five years of the study period and about $120 per MW-day higher than the LTER Reference Case in 2030 for both climate change scenarios.
- Maryland CO_2 emissions in the climate change scenario are marginally higher than in the LTER Reference Case and above the RGGI budget for all years after 2018.

12. ADDITIONAL SCENARIOS

Note: There are five additional scenarios runs that have been requested by the Power Plant Advisory Committee. These scenarios are:

1. Coal Plant Life-Extension Alternative Scenario plus Mt. Storm to Doubs – This scenario will consider postponed age-based retirements for certain PJM coal-fired power plants that have recently made investment in emissions control technology with the Mt. Storm to Doubs transmission upgrade added to the LTER Reference Case. All other assumptions will correspond to the LTER Reference Case assumptions.

2. PJM High Energy Efficiency plus Low Load Growth Alternative Scenario – this scenario will include aggressive energy efficiency programs implemented by all states within PJM combined with the low load growth assumptions.

3. Aggressive Energy Efficiency and High Renewables Alternative Scenario– this scenario will combine the Aggressive Energy Efficiency assumptions for Maryland with the High Renewables assumption of a 30 percent RPS.

4. Proposed EPA Regulations plus Mt. Storm to Doubs Alternative Scenario – this scenario will look at the potential impacts of newly proposed EPA air and water regulations (including Maximum Achievable Control Technology and 316(b)) with the Mt. Storm to Doubs transmission upgrade added to the LTER Reference Case. Based upon the results of this scenario, other alternative scenarios may be added.

5. Medium Renewable Alternative Scenario – this scenario will examine the effect of increasing the Maryland RPS requirement to a level midway between the LTER Refernce Case and the High Renewables scenario.

These scenario results will be provided with the Final Draft Report.

13. DISCUSSION TOPICS

13.1 Introduction

The previous chapters described the results of the numerous scenarios and combinations of scenarios. In this chapter we discuss certain topics that are relevant to electricity planning in Maryland. These topics are fuel diversity, reliability, emissions, price stability, life cycle costs for Calvert Cliffs Unit 3 and renewable energy, total production costs, Renewable Energy Certificate ("REC") prices, and retail bill impacts.

13.2 Fuel Diversity

13.2.1 Introduction

Fuel diversity is addressed to help gauge Maryland's exposure to fuel supply disruptions and to generally facilitate assessment of the State's risk with regard to the availability of generation. To calculate a fuel diversity measure for electric generation in Maryland, we have applied a variation of the Herfindahl-Hirschman Index (HHI). This index is normally used to estimate market concentration in a particular industry. The index is defined as the sum of the squares of each firm's market share. The HHI is given by the formula:

$$HHI = \sum_{i=1}^{N} S_i^2$$

where S_i is the market share of the i^{th} firm.[22]

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[22] Jean Tirole, The Theory of Industrial Organization (London: The MIT Press, 2003), p. 221; F. M. Scherer, Industrial Market Structure and Economic Performance, Second Edition (Boston: Houghton Mifflin Company, 1980), p. 58.

When an industry is occupied by only one firm (i.e., a monopoly), the index takes a value of 1. As more firms enter the market, the value of the index declines; however, the greater the inequality among market participants, that is, the more concentrated the industry, the higher the value of the index. By definition, the minimum value of the index is equal to (1/*N*), where *N* is the number of firms participating in the market.

For use in this report, S_i is defined as the share of generation for the i^{th} fuel. We have allowed for four fuel types for electricity generation in Maryland: natural gas (*g*), coal (*c*), nuclear (*n*), and renewables (*r*). We have also made two other modifications to make the index more intuitive. First, we subtract the index from one, so that the higher the index value, the higher the degree of diversity. Second, we multiply the index by four-over-three (i.e., 1.333) so the index value covers the range of zero to one. Therefore, the fuel diversity factor ("FDF") is defined by the following formula:

$$FDF_t = (1 - (S_{gt}{}^2 + S_{ct}{}^2 + S_{nt}{}^2 + S_{rt}{}^2))\ x\ 1.333$$

Where: FDF_t is the fuel diversity factor in time period t;

S_{gt} is the share of total MWh generation attributable to natural gas in time period t;

S_{ct} is the share of total MWh generation attributable to coal in time period t;

S_{nt} is the share of total MWh generation attributable to nuclear in time period t; and

S_{rt} is the share of total MWh generation attributable to renewables in time period t.

As stated above, the maximum value of FDF (i.e., maximum diversity) is 1.0 and results when all fuels have an equal share of total MWh generation:

$$FDF = (1 - (0.25^2 + 0.25^2 + 0.25^2 + 0.25^2)) \times 1.333 = 1.0$$

The minimum value of FDF (i.e., minimum diversity) is 0 and occurs only in the case where one fuel accounts for all generation. For example, if all electricity in Maryland were to be generated using coal as a fuel, the index would take the following value:

$$FDF = (1 - (0^2 + 1^2 + 0^2 + 0^2)) \times 1.333 = 0.0$$

In a case where there are unequal shares of generation, but no one fuel accounts for all generation, the FDF value will be between 0.0 and 1.0. For example, if natural gas accounts for 15 percent of generation, coal accounts for 60 percent, nuclear accounts for 20 percent, and renewables account for 5 percent, the FDF would equal:

$$FDF = (1 - (0.15^2 + 0.60^2 + 0.20^2 + 0.05^2)) \times 1.333 = 0.77$$

For any particular scenario, the Fuel Diversity Factor will vary from year to year depending on the degree to which new generating resources are added, the degree to which new generation facilities differ from existing generation facilities in terms of fuel, and the degree to which the existing stock of generating facilities is retired.

13.2.2 Diversity in Maryland Generation

Table 13.1, Table 13.2, and Table 13.3 show the calculated FDFs for Maryland generation for each of the scenarios considered, including the LTER Reference Case. To allow the data to be presented in a way that can be meaningfully interpreted, the FDF values are shown for 2010, 2020, and 2030.

In 2010, the FDF is between 0.70 and 0.75 for all scenarios. By 2020, all of the scenarios exhibit increases in the FDF as natural gas plants begin to be added in PJM-SW. The bulk of scenarios show Fuel Diversity Factors of between 0.75 and 0.77 in 2020. The highest increases, that is, those scenarios showing the highest FDFs in 2020, are those scenarios based on high load growth, which entail more rapid construction of natural gas-fired generation. These scenarios are characterized by FDF's of approximately 0.85. The climate change scenarios, which entail moderately more natural gas fired generation than in the LTER Reference Case, show FDFs of approximately 0.80. The lowest FDFs in 2020 (below 0.75) are associated with the low growth scenarios, which entail no new natural gas plants being constructed by 2020 to accommodate growth in load.

By 2030, the addition of significant natural gas generation results in FDFs above 0.80 for all scenarios. The highest FDFs, in excess of 0.95, are associated with the high renewables cases combined with national carbon legislation. Under the high renewables scenarios, more than 4,000 MW of new renewable resources are assumed to be constructed in Maryland, which, in combination with the effects of national carbon legislation, provides the greatest measures of diversity. The lowest FDFs are associated with these scenarios that are characterized by small increases in natural gas generation in PJM-SW. These scenarios include the LTER Reference Case plus Calvert Cliffs 3; the LTER Reference Case plus the Mt. Storm to Doubs transmission line; the aggressive energy efficiency plus Mt. Storm to Doubs scenario; and the climate change scenario that includes national carbon legislation and construction of Calvert Cliffs 3, the Mt. Storm to Doubs line, and the MAPP line.

Table 13.1
Fuel Diversity – Maryland 2010

Scenario	Nuclear (%)	Coal (%)	Gas (%)	Renewable (%)	Diversity Factor[23]
Reference Case	31.8	59.9	1.6	6.7	0.71
MSD	31.8	59.9	1.6	6.7	0.71
MAPP	31.8	59.9	1.6	6.7	0.71
CC3	31.8	59.9	1.6	6.7	0.71
MAPP + MSD	31.8	59.9	1.6	6.7	0.71
CC3+NCO2	31.8	59.9	1.6	6.7	0.71
CC3/NCO2/MSD/MAPP	31.8	59.9	1.6	6.7	0.71
NCO2	31.8	59.9	1.6	6.7	0.71
NCO2 + MSD	31.8	59.9	1.6	6.7	0.71
High Gas	31.2	60.8	1.4	6.6	0.70
High Gas + MSD	31.2	60.8	1.4	6.6	0.70
Low Gas	34.3	56.2	2.2	7.3	0.75
Low Gas + MSD	34.3	56.2	2.2	7.3	0.75
High Loads	31.8	59.9	1.6	6.7	0.71
High Load + MSD	31.8	59.9	1.6	6.7	0.71
High Load + CC3/NCO2/MSD/MAPP	31.8	59.9	1.6	6.7	0.71
Low Loads	31.8	59.9	1.6	6.7	0.71
Low Load + MSD	31.8	59.9	1.6	6.7	0.71
Low Load + CC3/NCO2/MSD/MAPP	31.8	59.9	1.6	6.7	0.71
High Renewables	31.8	59.9	1.6	6.7	0.71
High Renewables + MSD	31.8	59.9	1.6	6.7	0.71
High Renewables/CC3/NCO2	31.8	59.9	1.6	6.7	0.71
High Renewables + CC3/NCO2/MSD/MAPP	31.8	59.9	1.6	6.7	0.71
EE	31.8	59.9	1.6	6.7	0.71
EE + MSD	31.8	59.9	1.6	6.7	0.71
EE + CC3/NCO2	31.8	59.9	1.6	6.7	0.71
EE + CC3/NCO2/MSD/MAPP	31.8	59.9	1.6	6.7	0.71
Climate Change	31.8	59.9	1.6	6.7	0.71
Climate Change + CC3/NCO2/MSD/MAPP	31.8	59.9	1.6	6.7	0.71

[23] Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)
$(1-((\text{nuclear share})^2+(\text{coal share})^2+(\text{gas share})^2+(\text{renewables share})^2))\times(4/3)$

Table 13.2
Fuel Diversity – Maryland 2020

Scenario	Nuclear (%)	Coal (%)	Gas (%)	Renewable (%)	Diversity Factor[24]
Reference Case	27.5	58.4	4.5	9.6	0.76
MSD	27.5	58.5	4.4	9.6	0.76
MAPP	27.3	58.1	5.1	9.5	0.77
CC3	43.6	47.7	0.5	8.2	0.77
MAPP + MSD	29.1	60.0	0.9	10.0	0.73
CC3 + NCO2	43.8	47.6	0.4	8.2	0.77
CC3/NCO2/MSD/MAPP	43.6	47.9	0.5	8.0	0.77
NCO2	27.8	58.7	3.8	9.7	0.76
NCO2 + MSD	27.8	58.8	3.8	9.6	0.76
High Gas	27.5	58.3	4.5	9.7	0.76
High Gas + MSD	27.5	58.5	4.3	9.7	0.76
Low Gas	27.4	57.7	5.3	9.6	0.77
Low Gas + MSD	29.1	60.0	0.9	10.0	0.73
High Loads	24.8	52.9	13.6	8.7	0.84
High Load + MSD	26.4	56.0	8.6	9.0	0.80
High Load + CC3/NCO2/MSD/MAPP	38.0	43.5	11.3	7.2	0.86
Low Loads	29.4	59.8	0.5	10.3	0.73
Low Load + MSD	29.5	60.0	0.5	10.0	0.72
Low Load + CC3/NCO2/MSD/MAPP	44.0	47.7	0.3	8.0	0.76
High Renewables	28.9	59.3	0.9	10.9	0.74
High Renewables + MSD	28.9	59.3	0.9	10.9	0.74
High Renewables + CC3/NCO2	43.5	47.3	0.4	8.8	0.77
High Renewables + CC3/NCO2/MSD/MAPP	43.3	47.5	0.4	8.8	0.77
EE	29.1	60.1	0.9	9.9	0.73
EE + MSD	29.1	60.1	0.9	9.9	0.73
EE + CC3/NCO2	43.8	47.7	0.5	8.0	0.77
EE + CC3/NCO2/MSD/MAPP	43.4	48.0	0.6	8.0	0.77
Climate Change	26.1	55.5	9.2	8.9	0.81
Climate Change + CC3/NCO2/MSD/MAPP	40.0	45.7	6.9	7.4	0.83

[24] Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

Table 13.3
Fuel Diversity – Maryland 2030

Scenario	Nuclear (%)	Coal (%)	Gas (%)	Renewable (%)	Diversity Factor[25]
Reference Case	22.9	47.8	21.3	8.0	0.89
MSD	25.9	54.0	11.0	9.1	0.83
MAPP	22.1	46.2	24.0	7.7	0.90
CC3	40.8	45.8	5.6	7.8	0.82
MAPP + MSD	24.9	52.0	14.3	8.8	0.85
CC3 + NCO2	35.0	35.8	22.6	6.6	0.93
CC3/NCO2/MSD/MAPP	35.9	36.7	20.7	6.7	0.92
NCO2	20.8	39.6	32.3	7.3	0.92
NCO2 + MSD	23.2	44.2	24.5	8.1	0.91
High Gas	23.1	48.3	20.3	8.3	0.89
High Gas + MSD	23.1	48.3	20.5	8.1	0.89
Low Gas	22.6	47.0	24.6	5.8	0.89
Low Gas + MSD	25.6	53.0	12.6	8.8	0.84
High Loads	20.0	41.8	31.1	7.1	0.91
High Load + MSD	23.1	48.3	20.6	8.0	0.89
High Load + CC3/NCO2/MSD/MAPP	31.2	32.0	33.5	3.3	0.92
Low Loads	24.2	50.5	16.9	8.4	0.87
Low Load + MSD	24.3	50.8	16.4	8.5	0.87
Low Load + CC3/NCO2/MSD/MAPP	37.8	38.7	16.6	6.9	0.90
High Renewables	19.8	41.5	14.3	24.4	0.94
High Renewables + MSD	21.9	45.8	5.3	27.0	0.89
High Renewables + CC3/NCO2	31.2	32.0	16.2	20.6	0.98
High Renewables + CC3/NCO2/MSD/MAPP	30.7	31.5	17.5	20.3	0.98
EE	25.2	52.6	13.5	8.7	0.85
EE + MSD	26.0	54.5	10.5	9.0	0.82
EE + CC3/NCO2	35.2	36.0	22.2	6.6	0.92
EE + CC3/NCO2/MSD/MAPP	36.0	37.0	21.0	6.0	0.91
Climate Change	21.5	45.0	28.0	5.5	0.89
Climate Change + CC3/NCO2/MSD/MAPP	24.6	45.0	34.9	4.8	0.82

[25] Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

13.2.3 Diversity in PJM Generation

Maryland does not obtain its supply of electric power from generation resources located only in Maryland. Power generated in Maryland may be exported out of the State and power generated in other states may be imported to Maryland. To recognize that Maryland does not receive its electric power supply as if it were an island, we have also computed FDFs for PJM as a whole, which more accurately reflects the diversity of the fuel supply used to provide electric power to the State. These results are presented in Table 13.4, Table 13.5, and Table 13.6 in the same manner as the analogous data were presented in the previous tables.

In 2010, Fuel Diversity Factors for PJM range between 0.74 and 0.78, with the differentials related exclusively to gas price differentials which affect the dispatch order of resources. In 2020, the FDFs for all scenarios increase with increases in natural gas generation and increased generation from renewable resources. Renewable generation in PJM increases from approximately three percent in 2010 to between seven and 10 percent in 2020, depending on the scenario assumptions. The range of FDFs in PJM in 2020, however, remains narrow – between 0.81 and 0.85. The scenario with the highest FDF is the high load growth scenario that includes natural carbon legislation and construction of Calvert Cliffs 3, the Mt. Storm to Doubs line, and the MAPP line.

By 2030, Fuel Diversity Factors are shown to increase for all scenarios, again due to increasing natural gas and renewables generation. The 2030 FDFs range from 0.86 to 0.95. The scenarios with the greatest fuel diversity are those that include Calvert Cliffs 3 as a new resource or include national carbon legislation.

Table 13.4
Fuel Diversity – PJM 2010

Scenario	Nuclear (%)	Coal (%)	Gas (%)	Renewable (%)	Diversity Factor[26]
Reference Case	31.1	57.8	8.0	3.1	0.75
MSD	31.1	57.8	8.0	3.1	0.75
MAPP	31.1	57.8	8.0	3.1	0.75
CC3	31.1	57.8	8.0	3.1	0.75
MAPP + MSD	31.1	57.8	8.0	3.1	0.75
CC3 + NCO2	31.1	57.8	8.0	3.1	0.75
CC3/NCO2/MSD/MAPP	31.1	57.8	8.0	3.1	0.75
NCO2	31.1	57.8	8.0	3.1	0.75
NCO2 + MSD	31.1	57.8	8.0	3.1	0.75
High Gas	30.9	58.3	7.7	3.1	0.74
High Gas + MSD	30.9	58.3	7.7	3.1	0.74
Low Gas	31.4	55.9	9.5	3.2	0.77
Low Gas/MSD	30.4	56.0	9.5	4.1	0.78
High Loads	31.1	57.8	8.0	3.1	0.75
High Load + MSD	31.1	57.8	8.0	3.1	0.75
High Load + CC3/NCO2/MSD/MAPP	31.1	57.8	8.0	3.1	0.75
Low Loads	31.1	57.8	8.0	3.1	0.75
Low Load/MSD	31.1	57.8	8.0	3.1	0.75
Low Load + CC3/NCO2/MSD/MAPP	31.1	57.8	8.0	3.1	0.75
High Renewables	31.1	57.8	8.0	3.1	0.75
High Renewables + MSD	31.1	57.8	8.0	3.1	0.75
High Renewables + CC3/NCO2	31.1	57.8	8.0	3.1	0.75
High Renewables + CC3/NCO2/MSD/MAPP	31.1	57.8	8.0	3.1	0.75
EE	31.1	57.8	8.0	3.1	0.75
EE + MSD	31.1	57.8	8.0	3.1	0.75
EE + CC3/NCO2	31.1	57.8	8.0	3.1	0.75
EE + CC3/NCO2/MSD/MAPP	31.1	57.8	8.0	3.1	0.75
Climate Change	31.1	57.8	8.0	3.1	0.75
Climate Change + CC3/NCO2/MSD/MAPP	31.1	57.8	8.0	3.1	0.75

[26] Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

Table 13.5
Fuel Diversity – PJM 2020

Scenario	Nuclear (%)	Coal (%)	Gas (%)	Renewable (%)	Diversity Factor[27]
Reference Case	29.3	53.7	9.5	7.5	0.81
MSD	29.3	53.7	9.5	7.5	0.81
MAPP	29.3	53.7	9.5	7.5	0.81
CC3	30.6	53.3	8.6	7.5	0.81
MAPP + MSD	29.3	53.5	9.7	7.5	0.82
CC3 + NCO2	31.1	51.8	7.8	9.3	0.83
CC3/NCO2/MSD/MAPP	31.1	51.9	7.6	9.4	0.83
NCO2	29.6	52.3	8.6	9.5	0.83
NCO2 + MSD	29.9	52.3	8.6	9.2	0.83
High Gas	29.3	54.0	9.0	7.7	0.81
High Gas + MSD	29.4	54.0	9.1	7.5	0.81
Low Gas	29.2	53.3	10.0	7.5	0.82
Low Gas + MSD	29.2	53.2	10.1	7.5	0.82
High Loads	27.9	52.3	12.6	7.2	0.84
High Load + MSD	27.9	52.3	12.6	7.2	0.84
High Load + CC3/NCO2/MSD/MAPP	29.0	50.8	11.0	9.2	0.85
Low Loads	30.5	53.8	7.9	7.8	0.81
Low Load + MSD	30.5	53.8	8.0	7.7	0.81
Low Load + CC3/NCO2/MSD/MAPP	32.4	51.3	6.7	9.6	0.82
High Renewables	28.9	53.4	9.5	8.2	0.82
High Renewables + MSD	28.9	53.5	9.6	8.0	0.82
High Renewables + CC3/NCO2	30.8	51.7	7.7	9.8	0.83
High Renewables + CC3/NCO2/MSD/MAPP	30.8	51.8	7.7	9.7	0.83
EE	29.1	53.7	9.4	7.8	0.82
EE + MSD	29.1	53.7	9.4	7.8	0.82
EE + CC3/NCO2	31.1	51.7	7.7	9.5	0.83
EE + CC3/NCO2/MSD/MAPP	31.0	51.8	7.7	9.5	0.83
Climate Change	28.7	53.2	10.4	7.7	0.82
Climate Change + CC3/NCO2/MSD/MAPP	30.5	52.0	8.2	9.3	0.83

[27] Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

Table 13.6
Fuel Diversity – PJM 2030

Scenario	Nuclear (%)	Coal (%)	Gas (%)	Renewable (%)	Diversity Factor[28]
Reference Case	25.2	46.9	19.0	8.9	0.90
MSD	25.3	47.0	18.9	8.8	0.90
MAPP	25.2	46.8	19.2	8.8	0.90
CC3	26.4	46.8	17.9	8.9	0.90
MAPP + MSD	25.2	46.9	19.0	8.9	0.90
CC3 + NCO2	26.6	42.3	20.1	11.0	0.93
CC3/NCO2/MAPP/MSD	26.6	42.1	20.4	10.9	0.93
NCO2	25.5	42.6	21.0	10.9	0.93
NCO2 + MSD	25.5	42.4	21.1	11.0	0.93
High Gas	25.4	47.2	18.3	9.1	0.89
High Gas + MSD	25.4	47.2	18.3	9.1	0.89
Low Gas	25.1	46.6	19.4	8.9	0.90
Low Gas + MSD	25.2	46.6	19.3	8.9	0.90
High Loads	23.0	43.2	25.7	8.1	0.92
High Load + MSD	23.1	43.3	25.5	8.1	0.92
High Load + CC3/NCO2/MSD/MAPP	24.3	39.2	25.9	10.6	0.95
Low Loads	28.0	50.3	11.8	9.9	0.86
Low Load + MSD	28.0	50.3	11.8	9.9	0.86
Low Load + CC3/NCO2/MSD/MAPP	29.5	45.2	14.0	11.3	0.90
High Renewables	25.2	46.8	17.9	10.1	0.90
High Renewables + MSD	25.2	46.9	17.7	10.2	0.90
High Renewables + CC3/NCO2	26.5	42.3	19.0	12.2	0.93
High Renewables + CC3/NCO2/MSD/MAPP	26.5	42.1	19.2	12.2	0.93
EE	25.4	47.3	18.4	8.9	0.89
EE + MSD	25.5	47.3	18.3	8.9	0.89
EE + CC3/NCO2	27.0	42.5	19.5	11.0	0.93
EE + CC3/NCO2/MSD/MAPP	27.0	42.4	19.6	11.0	0.93
Climate Change	24.8	46.1	20.4	8.7	0.90
Climate Change + CC3/NCO2/MSD/MAPP	26.2	42.0	21.1	10.7	0.93

[28] Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

13.3 Reliability

To provide reliable power supplies at reasonable prices, adequate electric infrastructure is required. The North American Electric Reliability Corporation ("NERC") is charged with developing guidelines and protocols for implementing the standards and assessing the reliability of the bulk power system. The NERC-developed standards are ultimately approved and made mandatory by the Federal Energy Regulatory Commission ("FERC"). Development of mandatory standards was a part of the Energy Policy Act of 2005 which was prompted by the Northeast blackout of August 2003. Since March 2007, FERC has approved numerous standards, including several initial cyber security standards. Several additional standards are under development or pending approval by FERC. NERC also delegates enforcement authority to eight regional reliability councils, including the ReliabilityFirst Corporation that serves the PJM area.

One of the reliability standards developed and enforced by the ReliabilityFirst Corporation is the Resource Planning Reserve Requirement. The standard requires that each load serving entity ("LSE") participating in PJM has sufficient resources to ensure no loss of load from insufficient resources for more than one day in ten years. In order to maintain compliance with this reliability standard, PJM conducts annual resource planning exercises to ensure all LSEs have sufficient generation resources to supply their peak electricity load, plus a specified annual reserve margin of approximately 15 percent.

PJM conducts reliability studies in order to forecast potential problems and to plan for the expansion and upgrade of the transmission system to mitigate or alleviate problems. PJM's

Regional Transmission Expansion Planning (RTEP) Process Reliability Assessment models future load and energy use and highlights potential problems and the effectiveness of proposed grid improvements. PJM has authority over the transmission system and an obligation to maintain reliability. Therefore, PJM itself can only put forward transmission solutions to reliability issues. PJM cannot impose generation or demand response solutions; it can include in its studies and its RTEP modeling only generation projects that have requested interconnection to the PJM grid and are at a relatively late stage of development. Additionally, only demand response resources that have cleared in the PJM's Reliability Pricing Model ("RPM") capacity market auction are recognized by PJM for purposes of reliability assessment. PJM develops a 5-year Transmission Plan that addresses near-term, reliability-related transmission constraints to identify needed transmission upgrades. PJM also develops a 15-year Transmission Plan that includes high-voltage regional upgrades to help alleviate long-term potential transmission issues identified by the modeling. Once a transmission constraint is identified, PJM authorizes construction and cost recovery of transmission upgrades to address the area of concern.

The Ventyx model recognizes the PJM transmission area's (and other areas) reliability criteria. The standards are built into the model structure, and at all times the Ventyx model meets the overall PJM reserve margin requirements and transmission system capacity limitations. This is why new generation capacity is constructed in higher cost zones such as PJM-SW as transmission limitations are reached and reliability standards need to be maintained. All of the scenarios analyzed as part of the LTER meet the necessary reliability standard due to the standard being an artifact of the model itself. None of the scenarios can be said to enhance reliability in Maryland more than any other scenario, as a reliable outcome is assured in every scenario by the Ventyx model structure.

13.4 Emissions from Electricity Consumption in Maryland

13.4.1 Introduction

The electricity consumed by Maryland end-users may or may not be generated from within the State since power generated in other states may be imported into Maryland and power generated in Maryland may be exported to other states. The emissions section for each scenario addressed in Chapters 4 through 12 presents data regarding projected emissions from power plants that are located in Maryland. These data, however, do not represent emissions related to consumption of electricity, but rather from the generation of electricity. This section is included to provide estimates of emissions associated with electricity consumed in Maryland.

To estimate the consumption-based emissions levels, we first calculated, for each pollutant, the ratio of PJM-wide emissions to the level of energy consumption in PJM for each year during the study period. The annual ratios were calculated for all of the LTER scenarios; for SO_2, NO_x, CO_2, and mercury. These ratios were then applied to the projected annual levels of energy consumption in Maryland under each scenario to estimate Maryland's pro-rata share of PJM emissions.

A specified percentage of Maryland's electricity is required to come from renewable energy sources each year pursuant to Maryland's Renewable Energy Portfolio Standard ("RPS"). Because of this requirement, we adjusted Maryland's projected level of energy consumption to account for this difference. For example, in 2011 Maryland's RPS stipulates that 5 percent of the electricity consumed in the State must come from Tier 1 renewable resources, but only about 3 percent of the electricity in PJM is projected to come from such resources.[29] Thus, in 2011, the emissions-to-consumption ratios were multiplied by 98 percent of the State's projected annual energy consumption to exclude the amount of renewable energy over and above the PJM system mix that must be consumed in Maryland to comply with Maryland's RPS. The 98 percent figure represents 100 percent of the PJM system generation mix, which includes 3 percent renewables, less the 2 percent additional renewables required under the RPS.

Based on these calculations, Figure 13.1 through Figure 13.24 illustrate the level of emissions associated with energy consumption in Maryland for each scenario considered in the LTER. There are three graphs for each pollutant which display the level of emissions in 2010, 2020, and 2030. Additionally, there are three graphs that show annual averages for the periods 2010 through 2030, 2010 through 2020, and 2021 through 2030.

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[29] Maryland's required level of renewable energy consumption was increased for the High Renewables scenarios.

Figure 13.1 2010 SO_2 Emissions from Electricity Consumption in Maryland

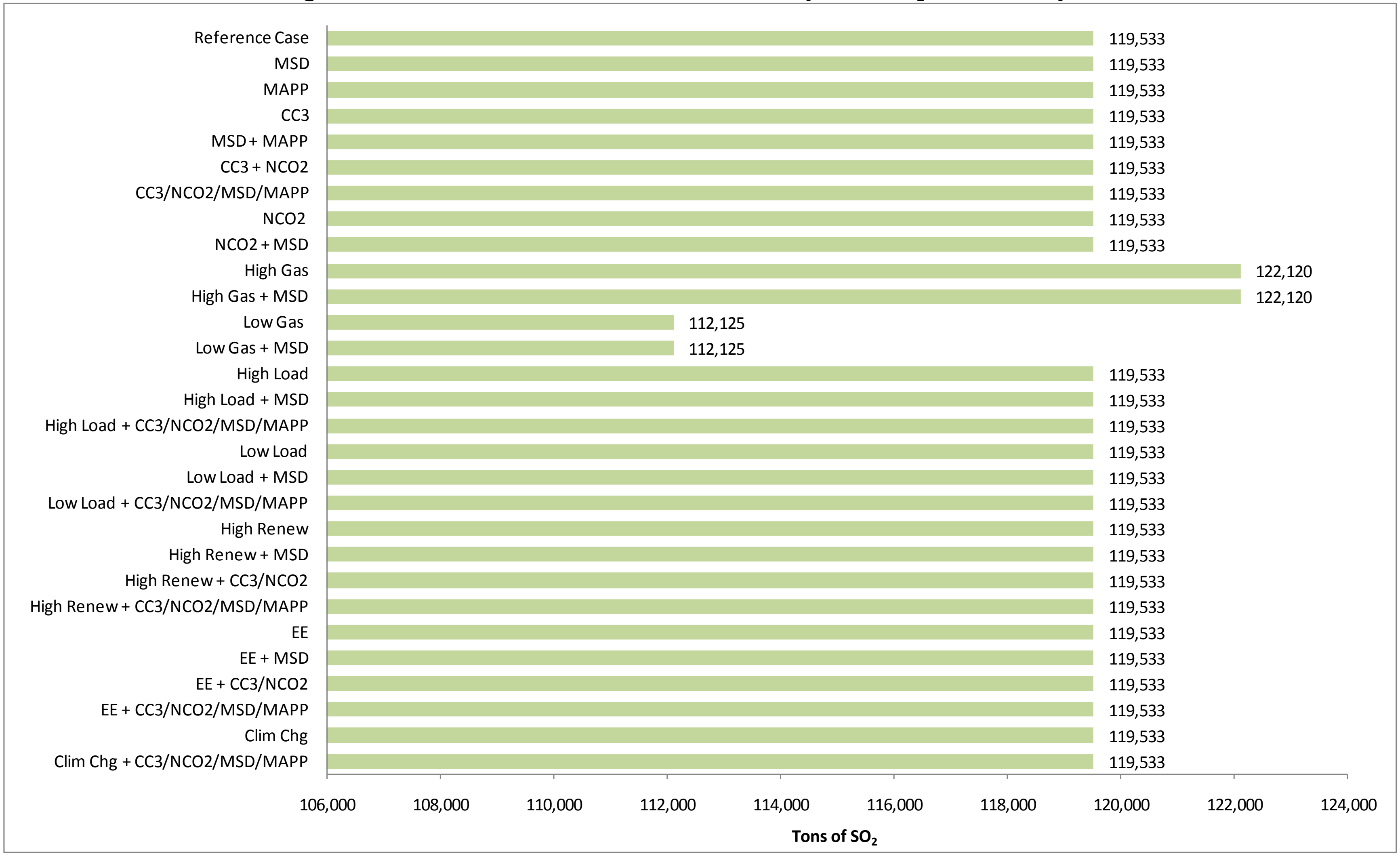


Figure 13.2 2020 SO_2 Emissions from Electricity Consumption in Maryland

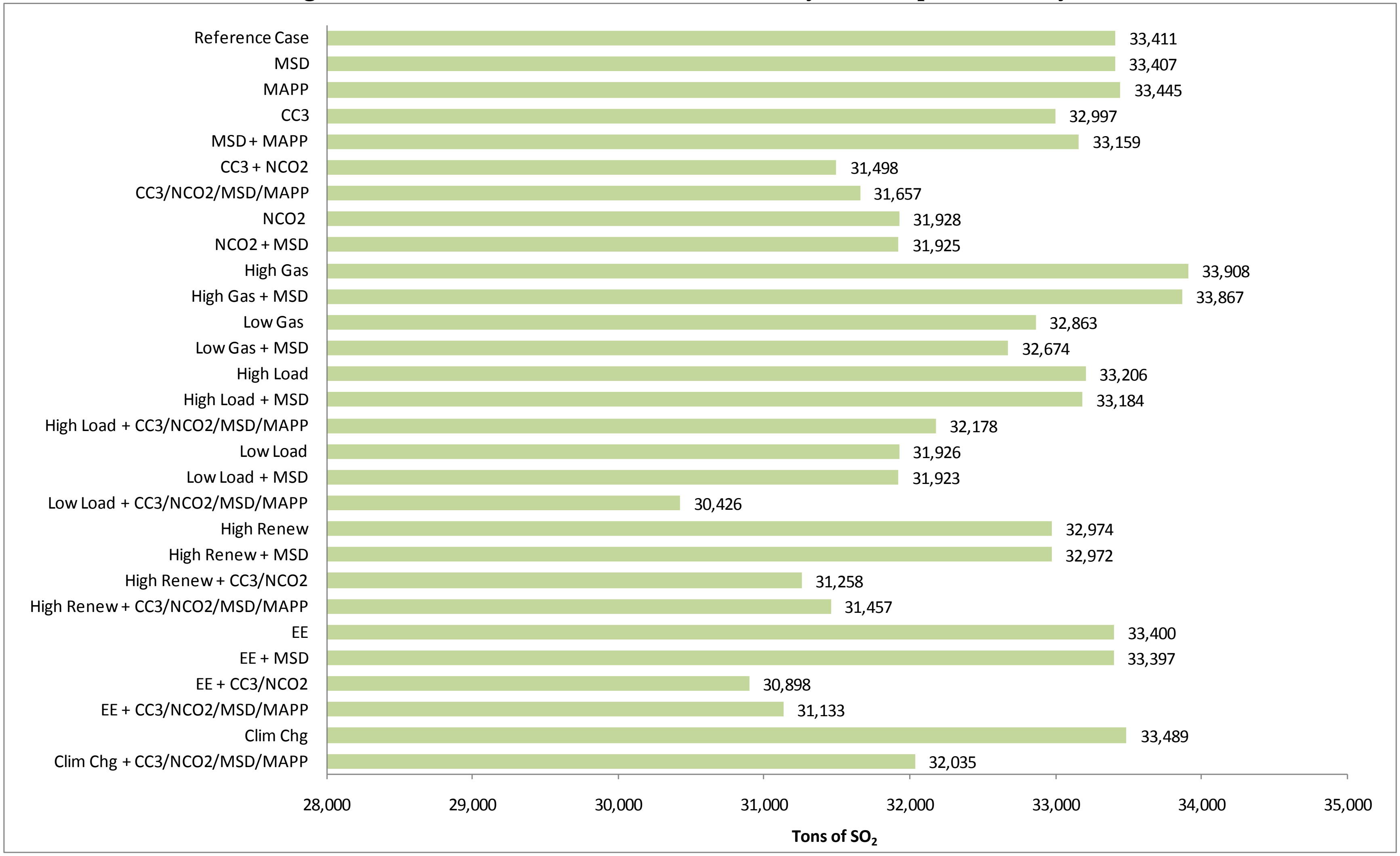


Figure 13.3 2030 SO_2 Emissions from Electricity Consumption in Maryland

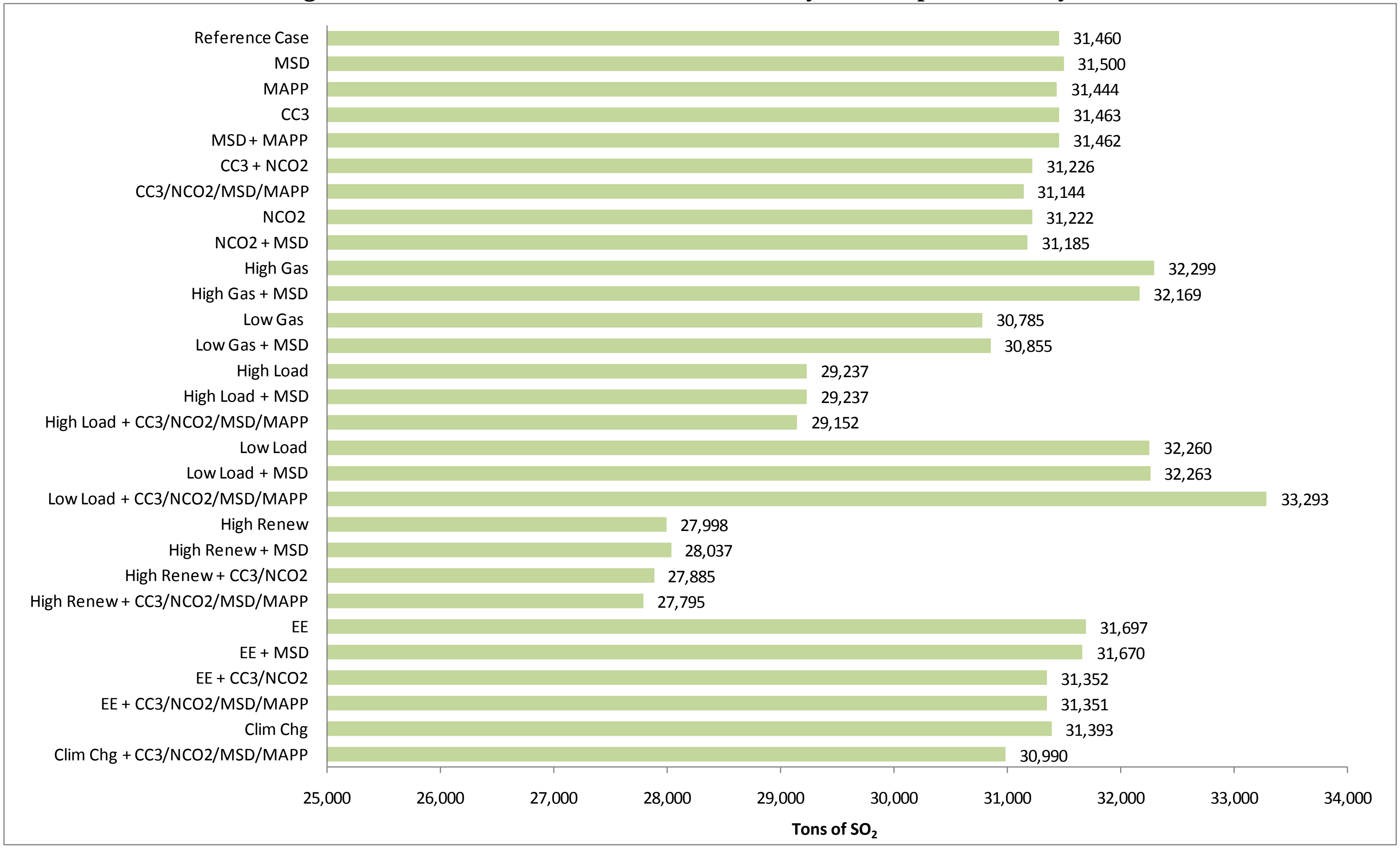


Figure 13.4 2010-2030 Avergae Annual SO_2 Emissions from Electricity Consumption in Maryland

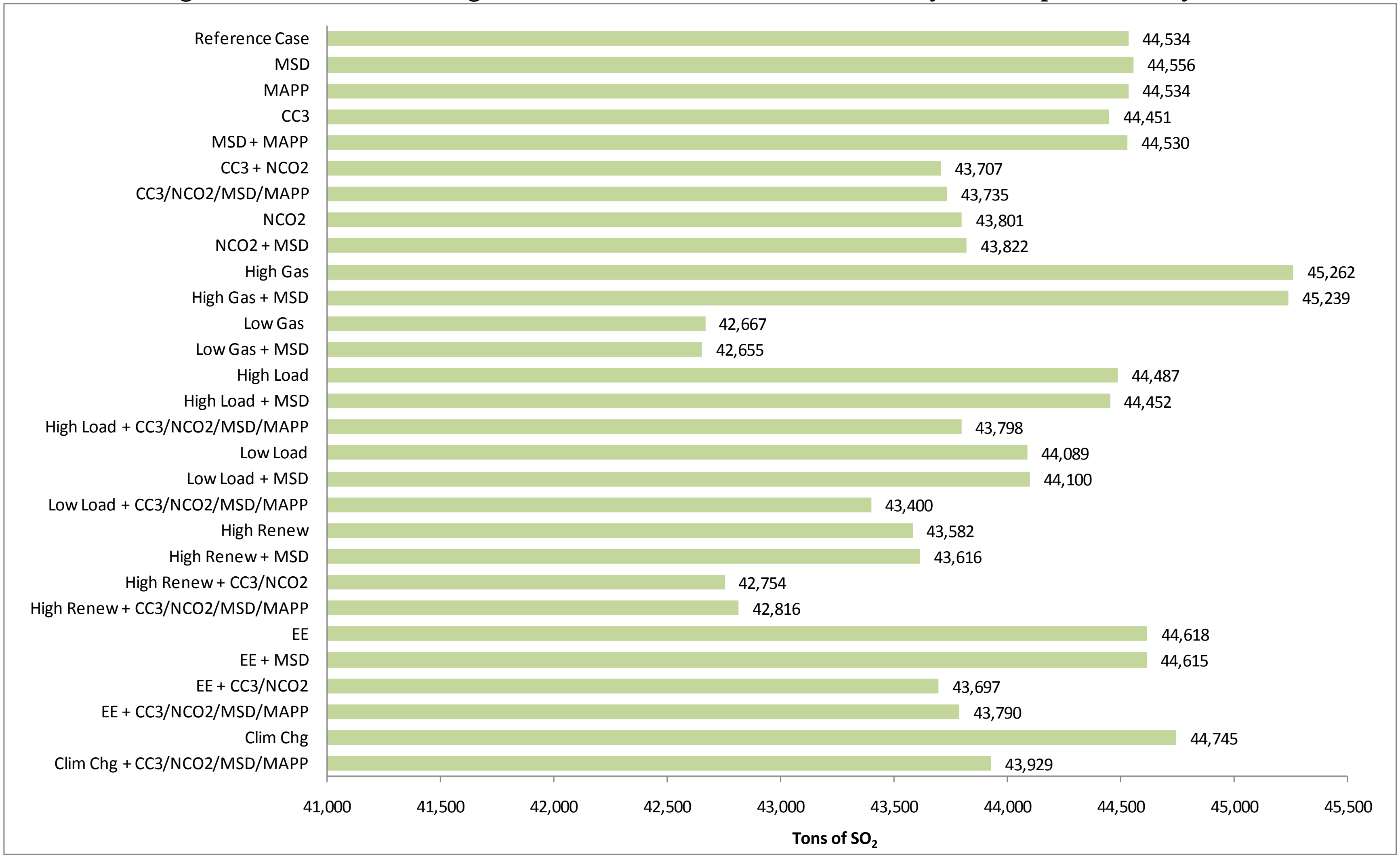


Figure 13.5 2010-2020 Average Annual SO_2 Emissions from Electricity Consumption in Maryland

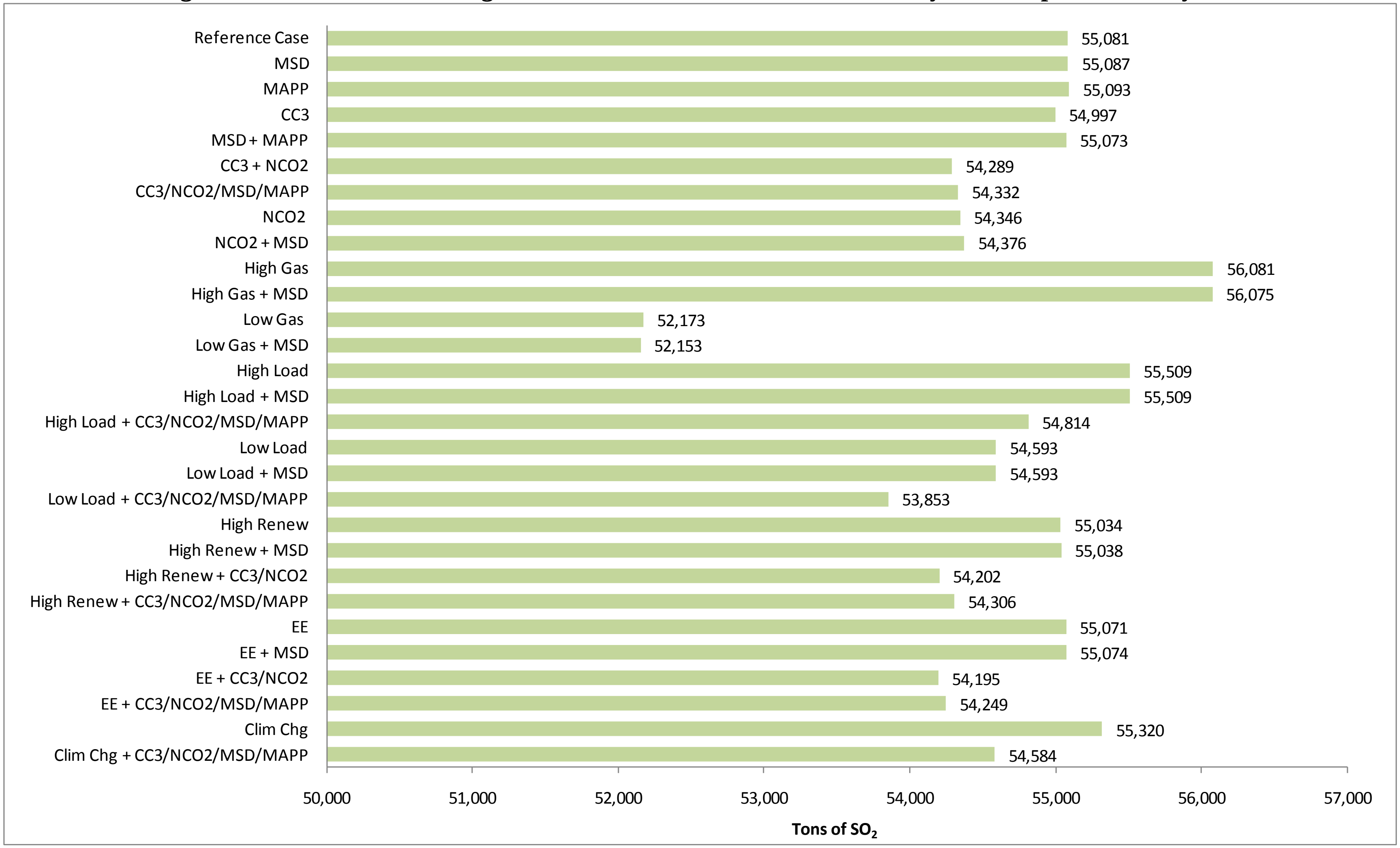


Figure 13.6 2021-2030 Average Annual SO_2 Emissions from Electricity Consumption in Maryland

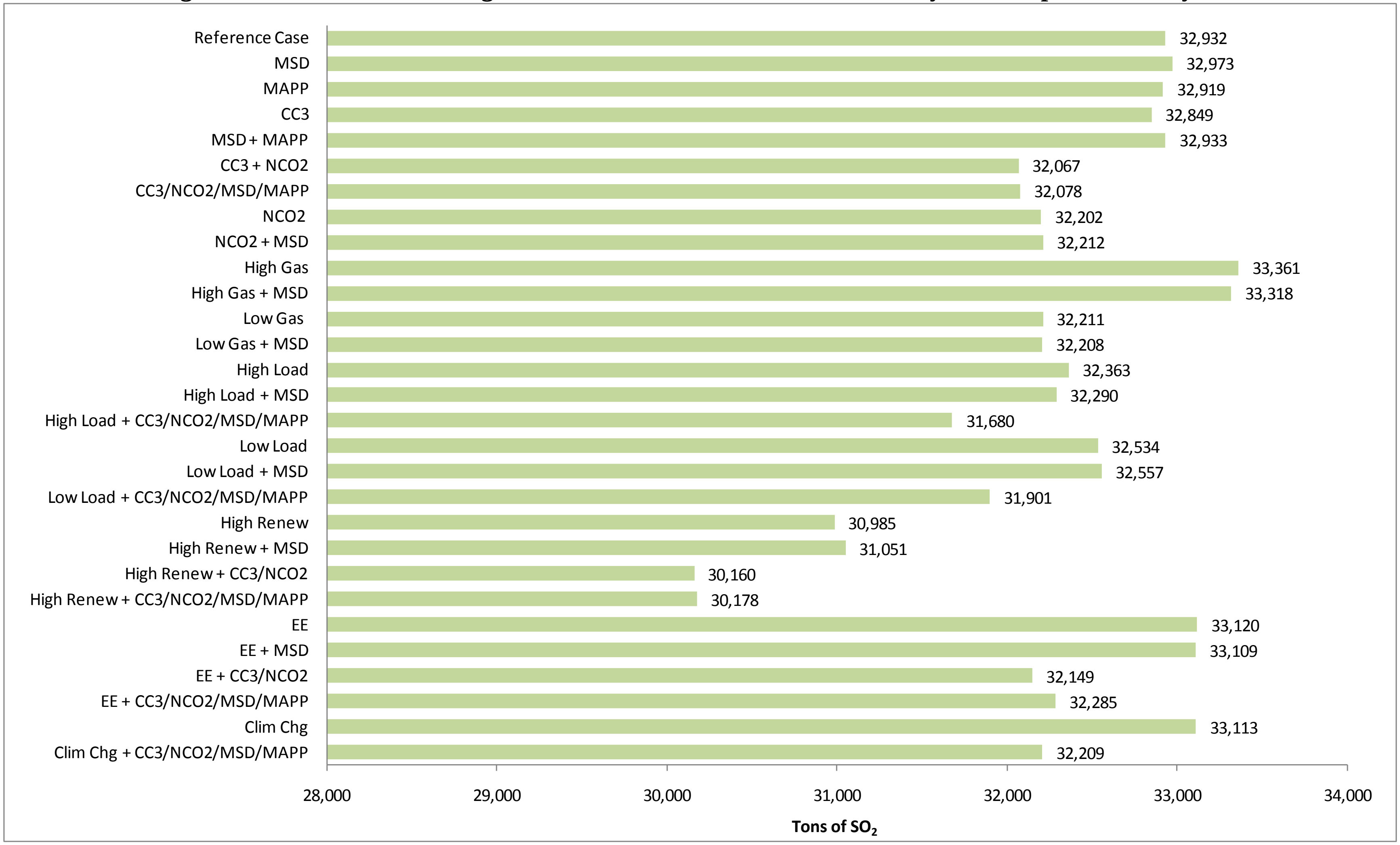


Figure 13.7 2010 NO_x Emissions from Electricity Consumption in Maryland

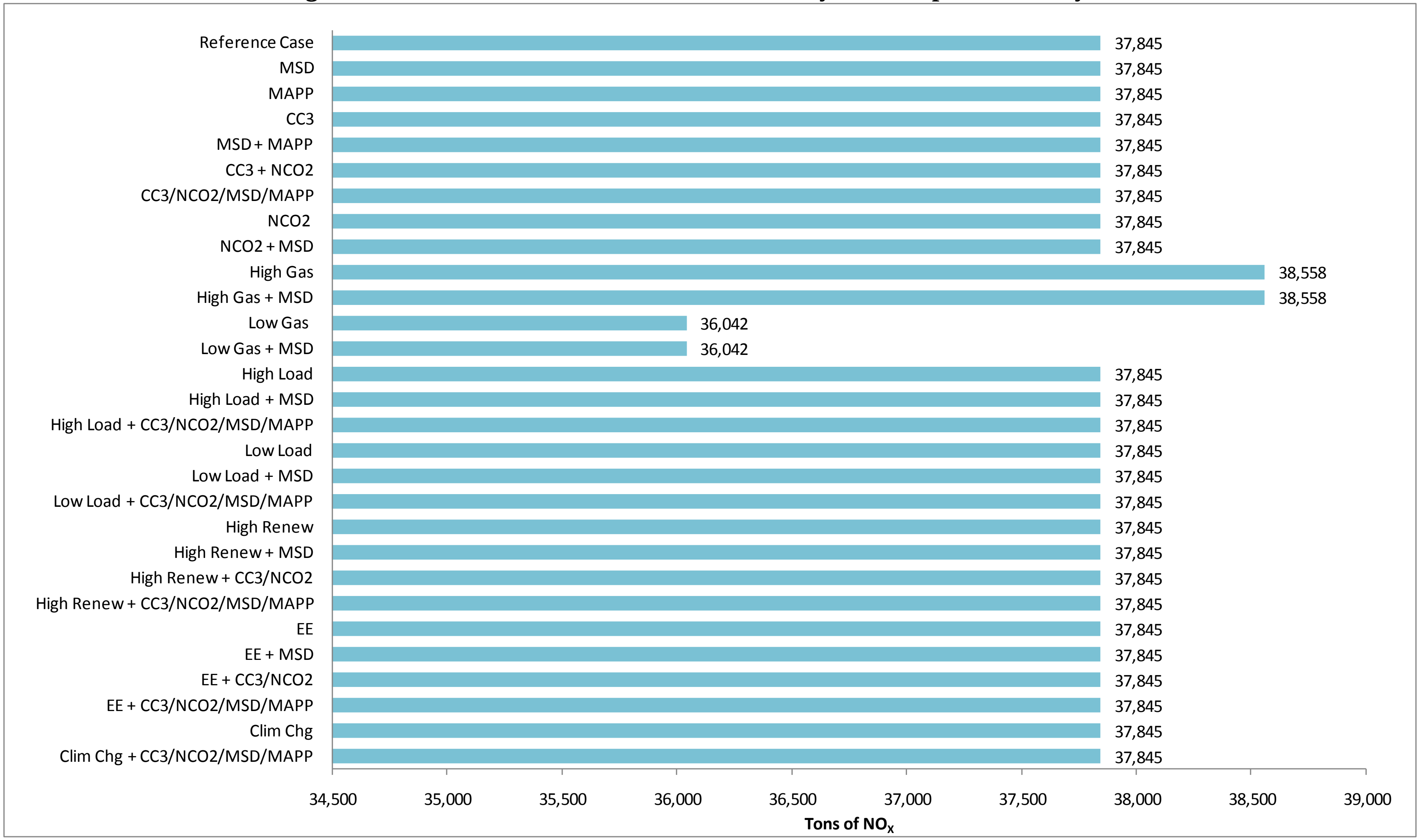


Figure 13.8 2020 NO_x Emissions from Electricity Consumption in Maryland

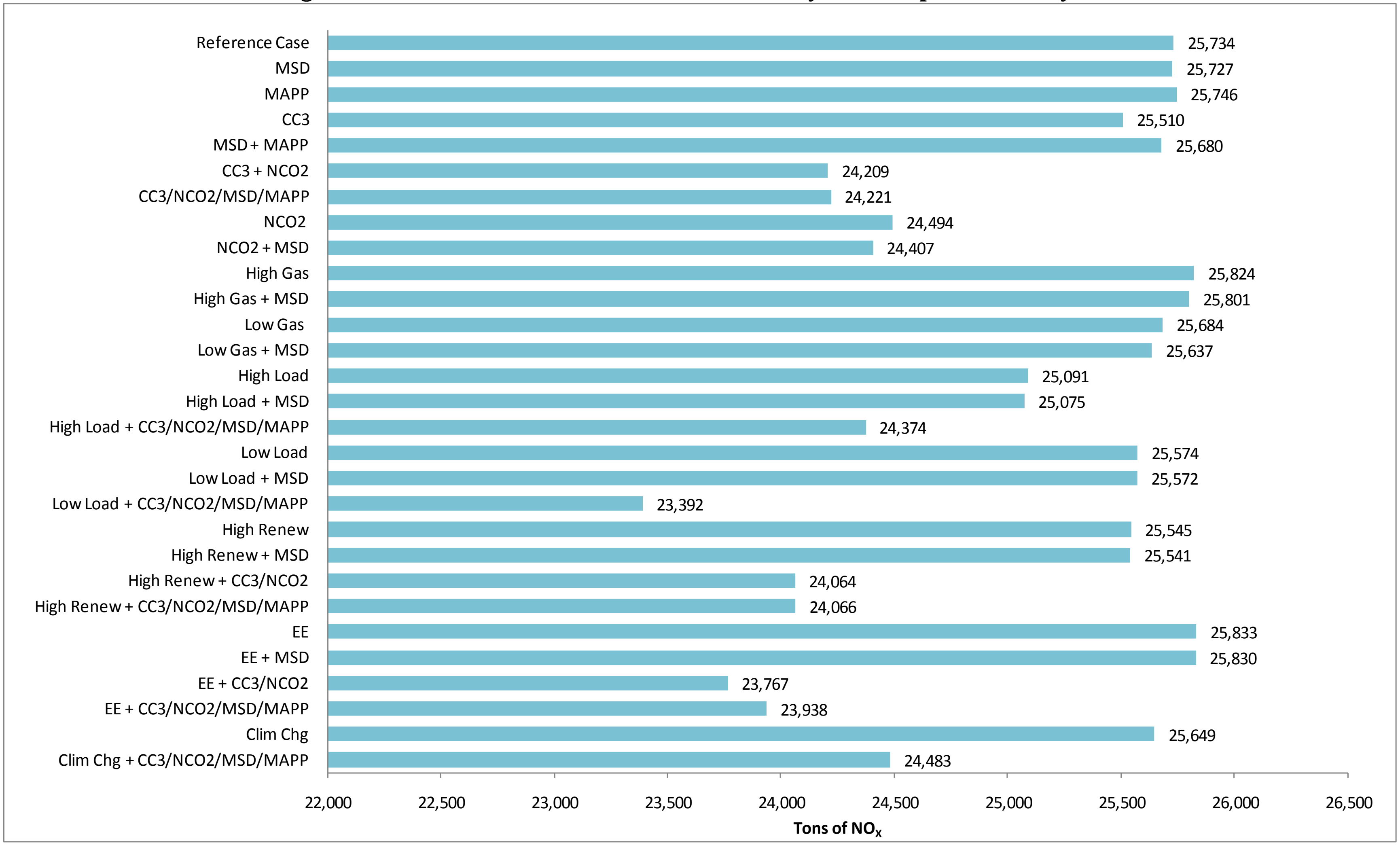


Figure 13.9 2030 NO_x Emissions from Electricity Consumption in Maryland

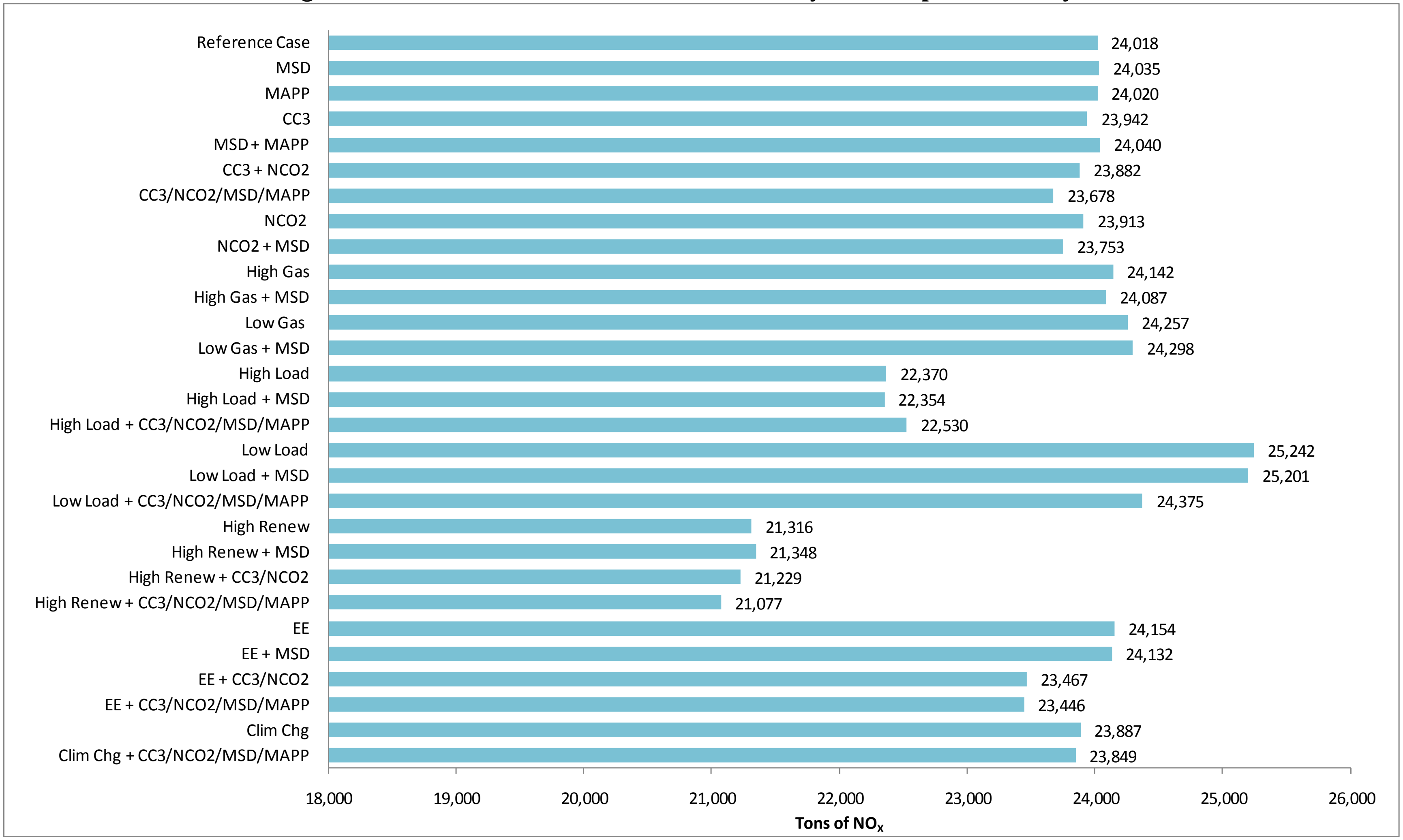


Figure 13.10 2010-2030 Avergae Annual NO_x Emissions from Electricity Consumption in Maryland

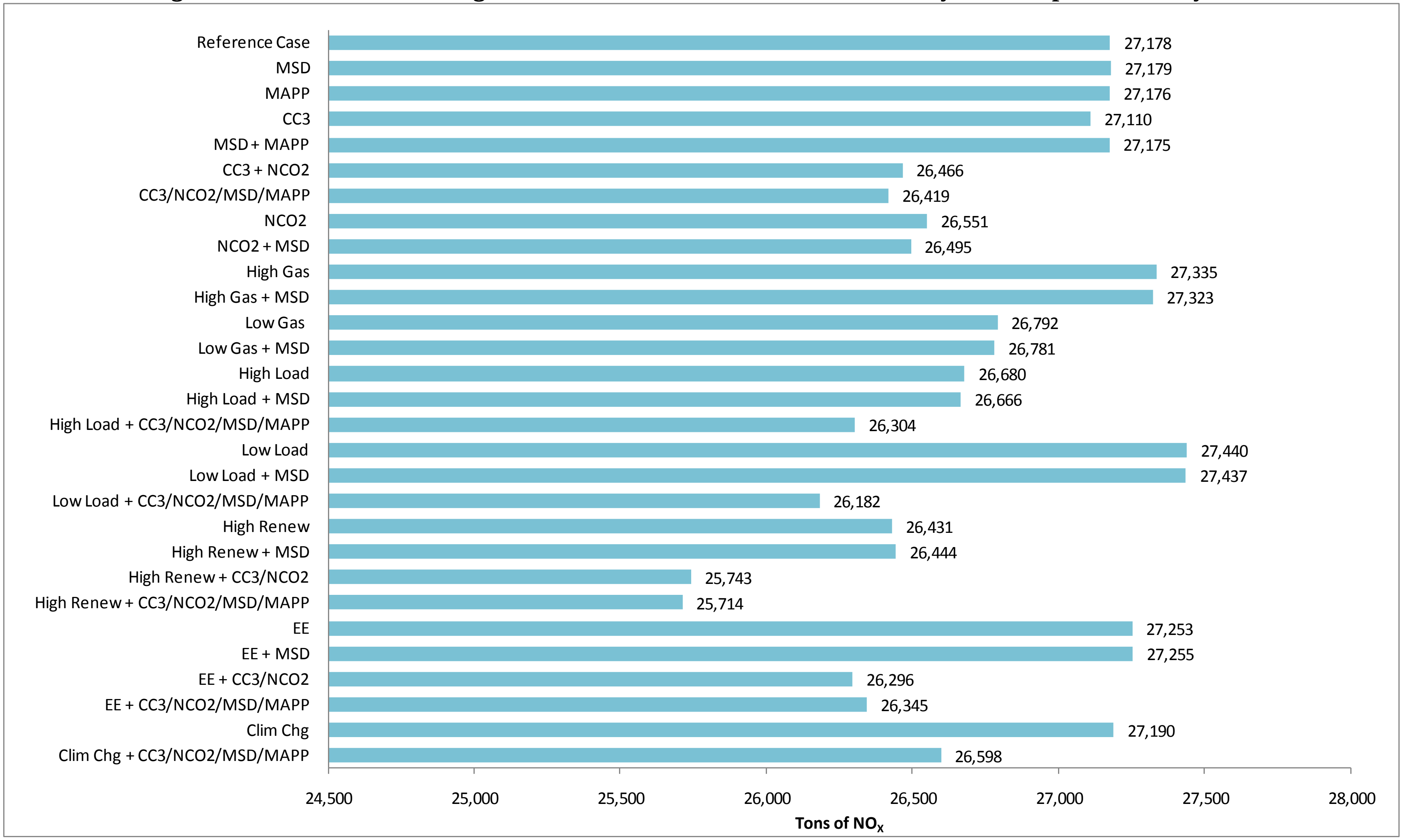


Figure 13.11 2010-2020 Average Annual NO_x Emissions from Electricity Consumption in Maryland

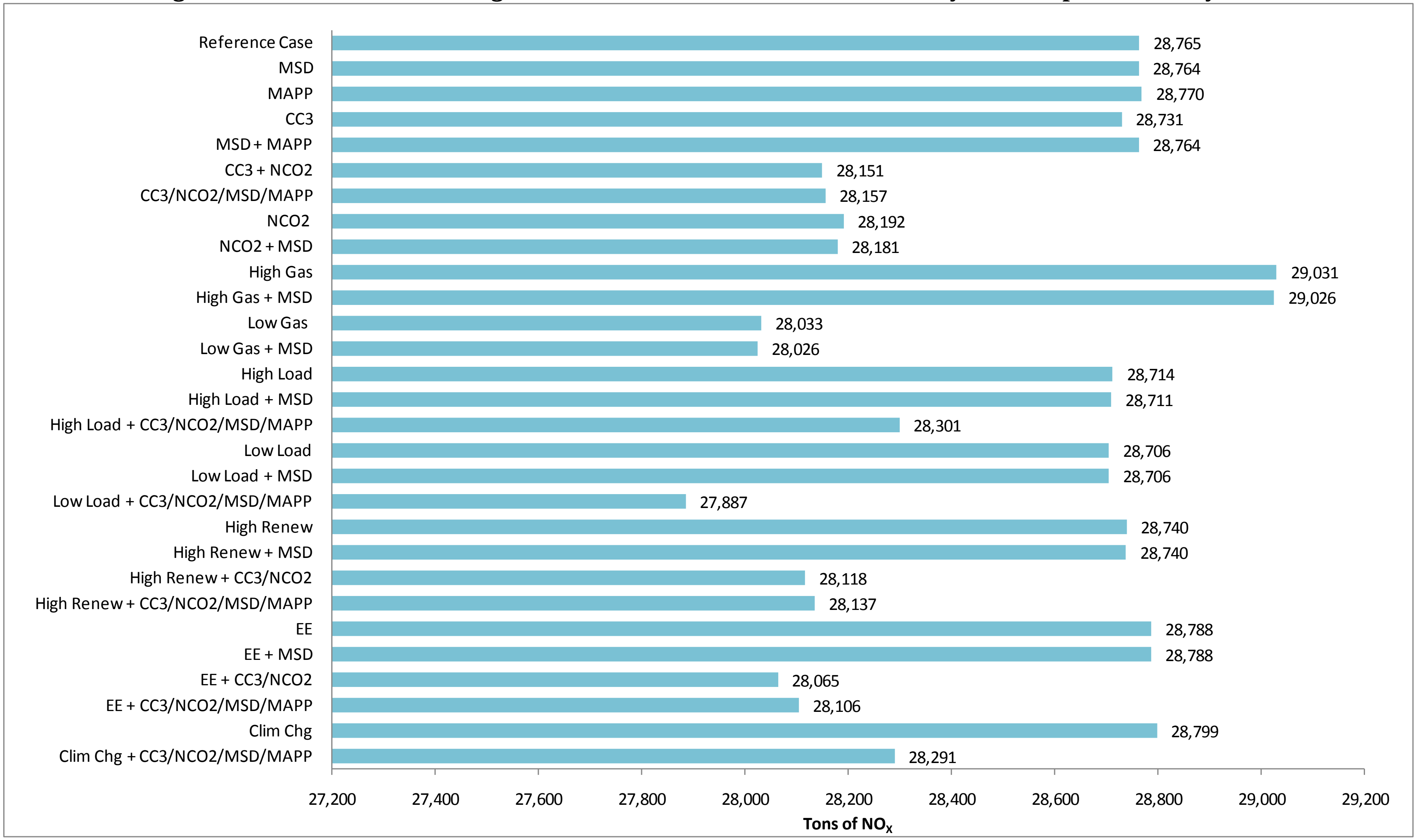


Figure 13.12 2021-2030 Average Annual NO_x Emissions from Electricity Consumption in Maryland

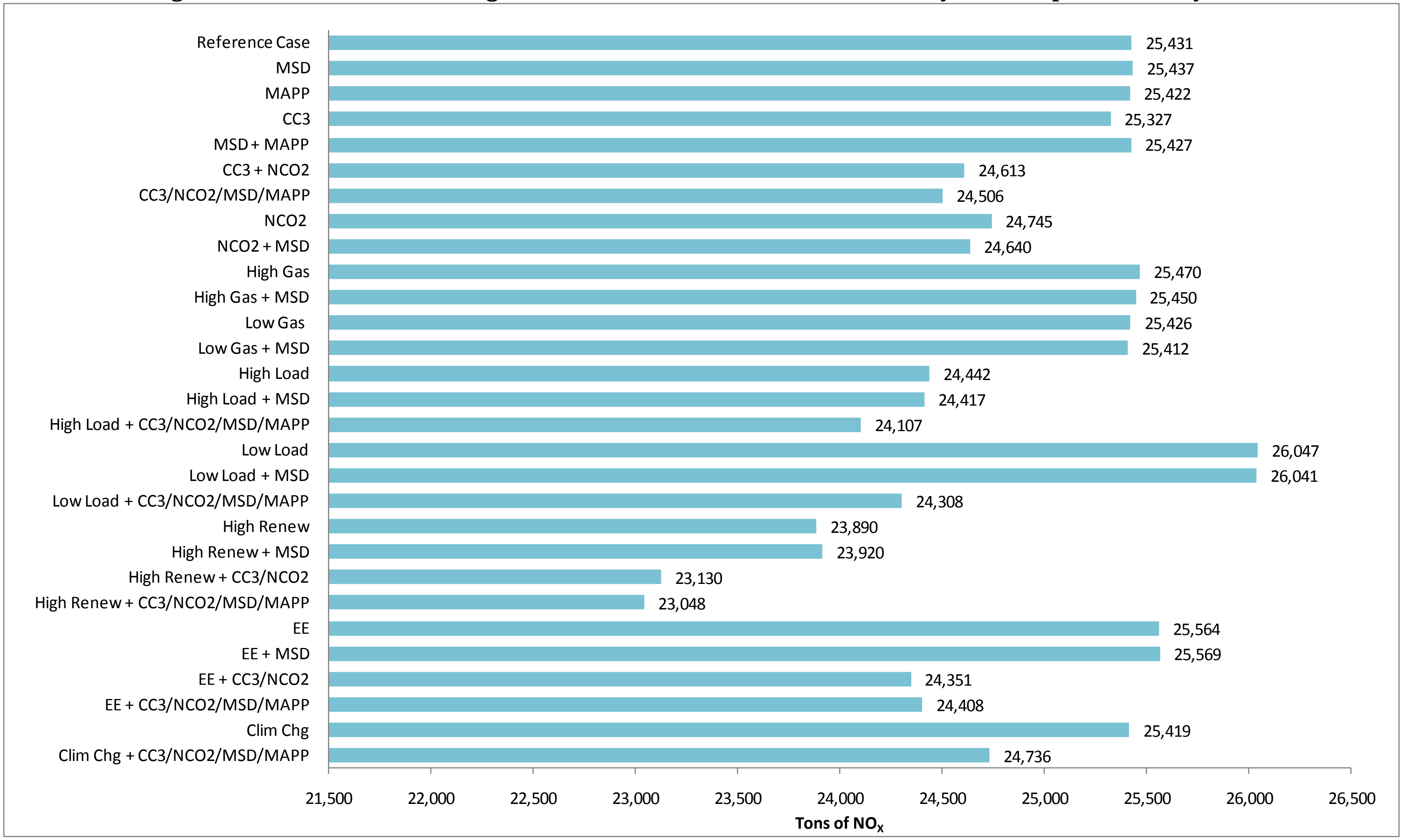


Figure 13.13 2010 CO_2 Emissions from Electricity Consumption in Maryland

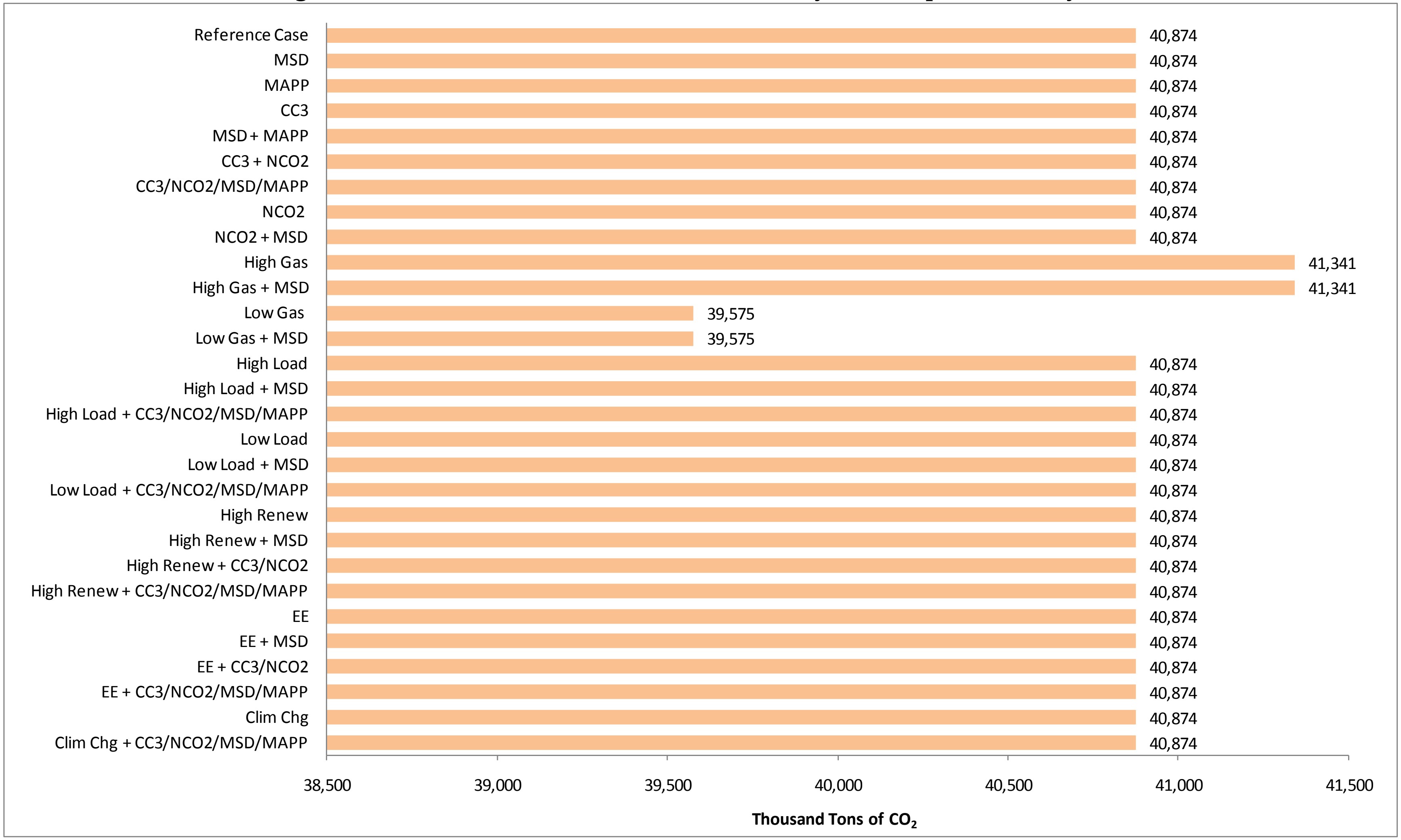


Figure 13.14 2020 CO_2 Emissions from Electricity Consumption in Maryland

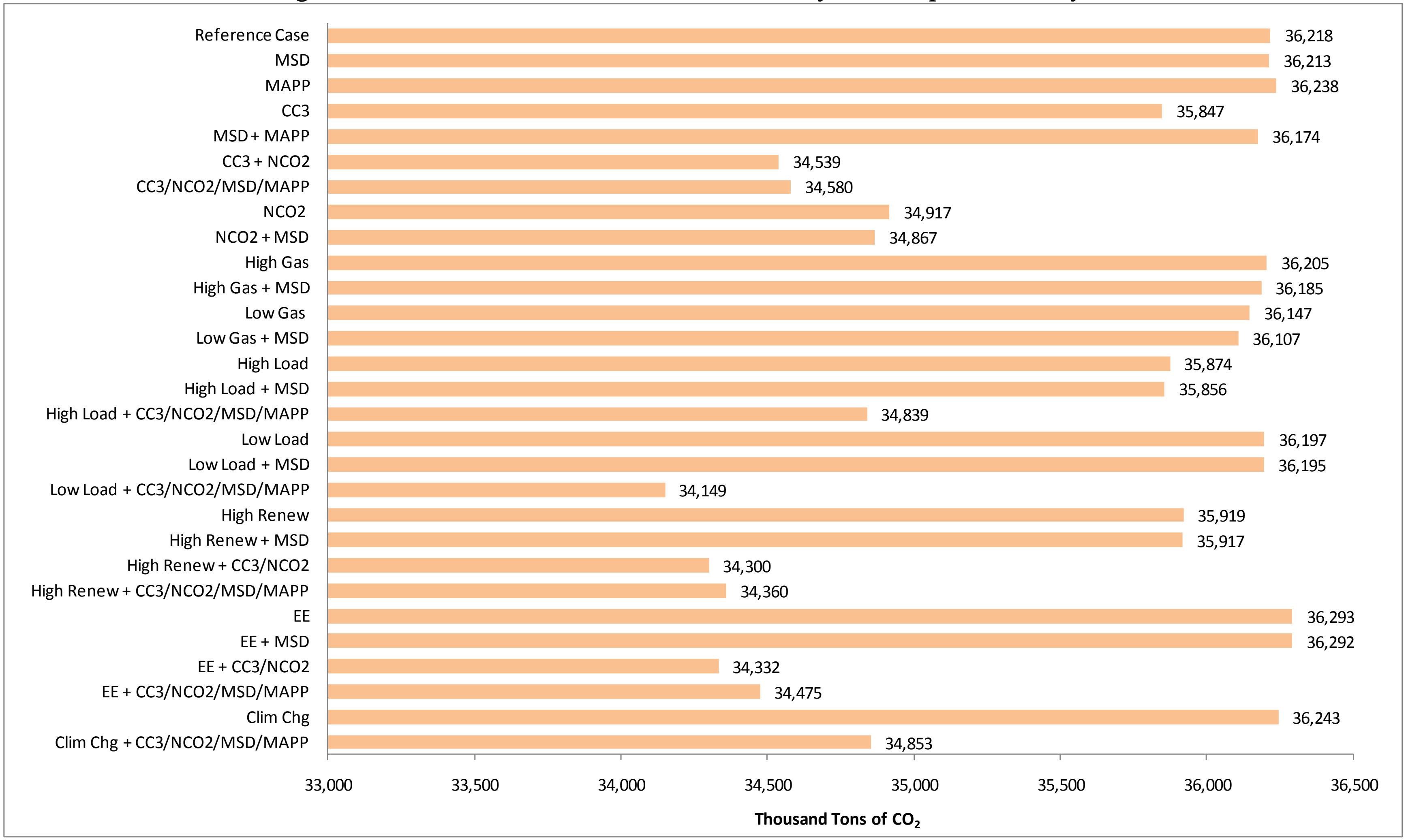


Figure 13.15 2030 CO_2 Emissions from Electricity Consumption in Maryland

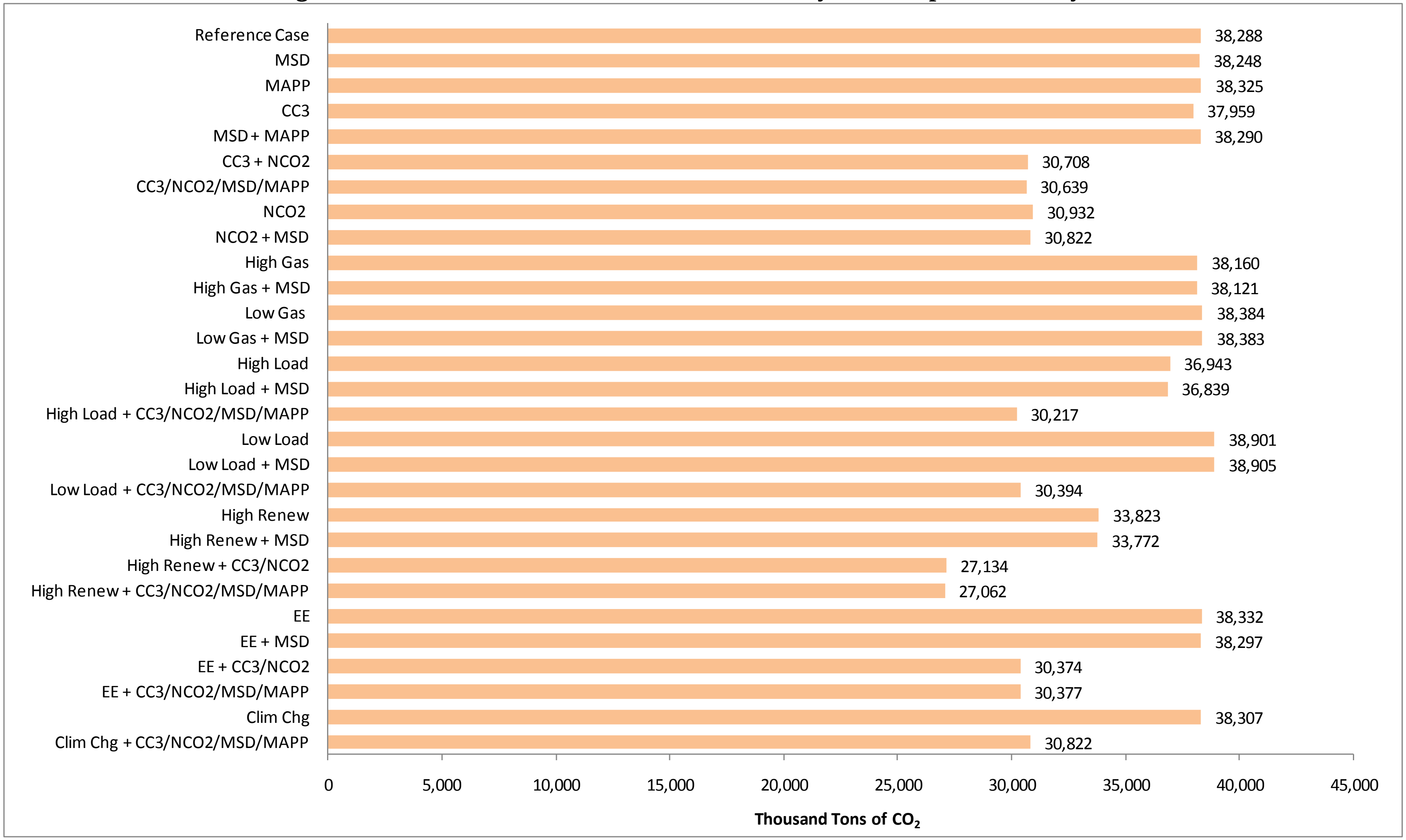


Figure 13.16 2010-2030 Avergae Annual CO_2 Emissions from Electricity Consumption in Maryland

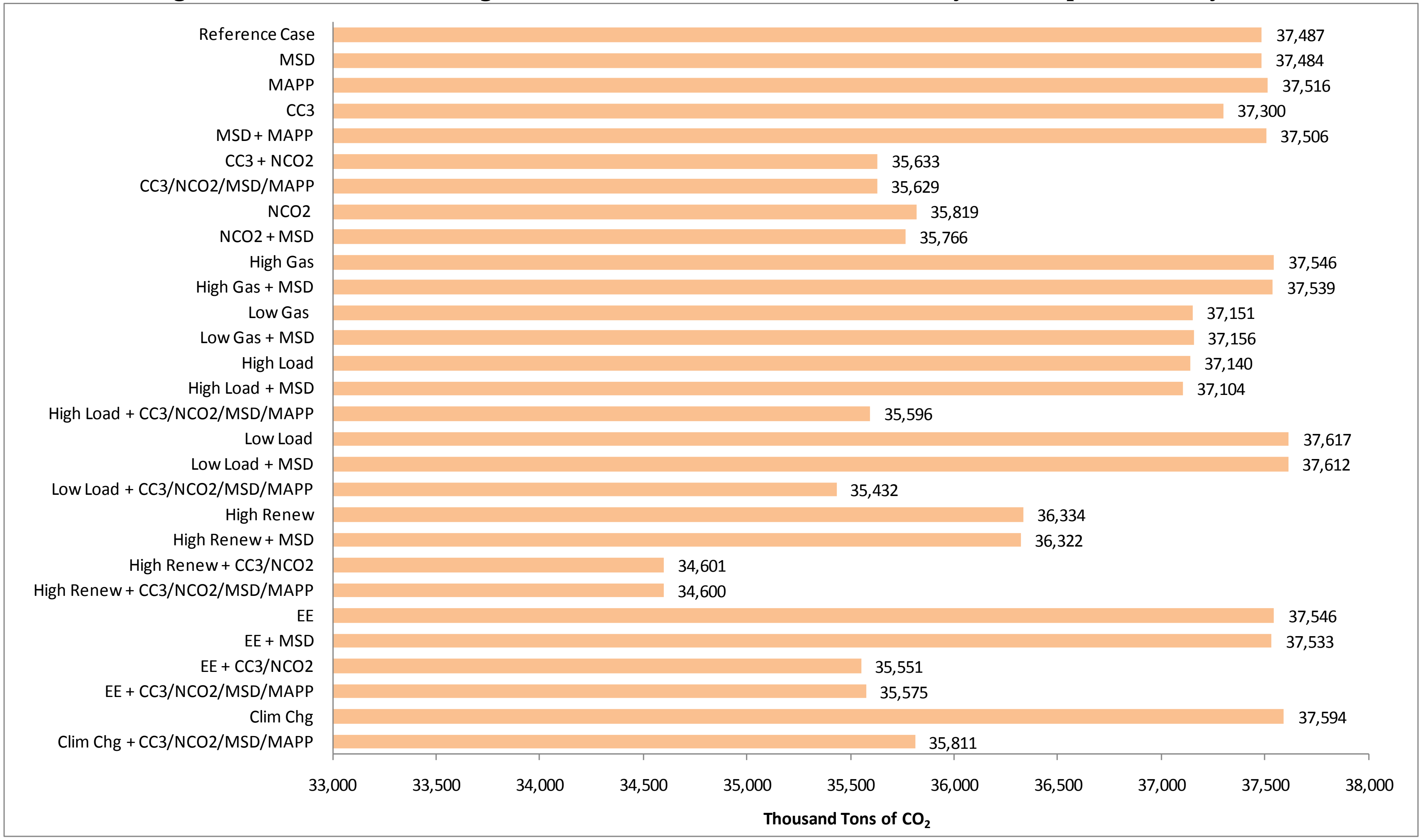


Figure 13.17 2010-2020 Average Annual CO_2 Emissions from Electricity Consumption in Maryland

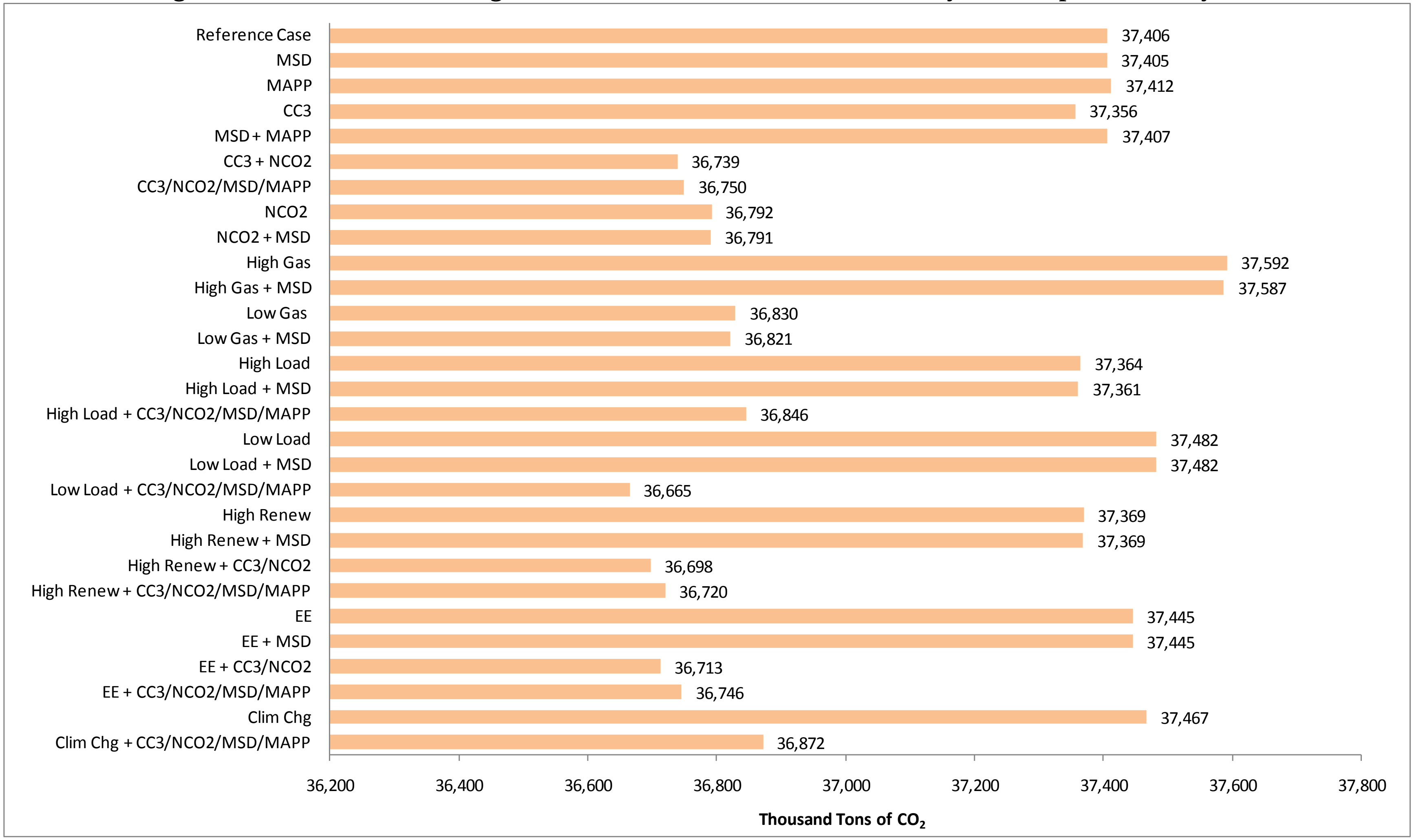


Figure 13.18 2021-2030 Average Annual CO_2 Emissions from Electricity Consumption in Maryland

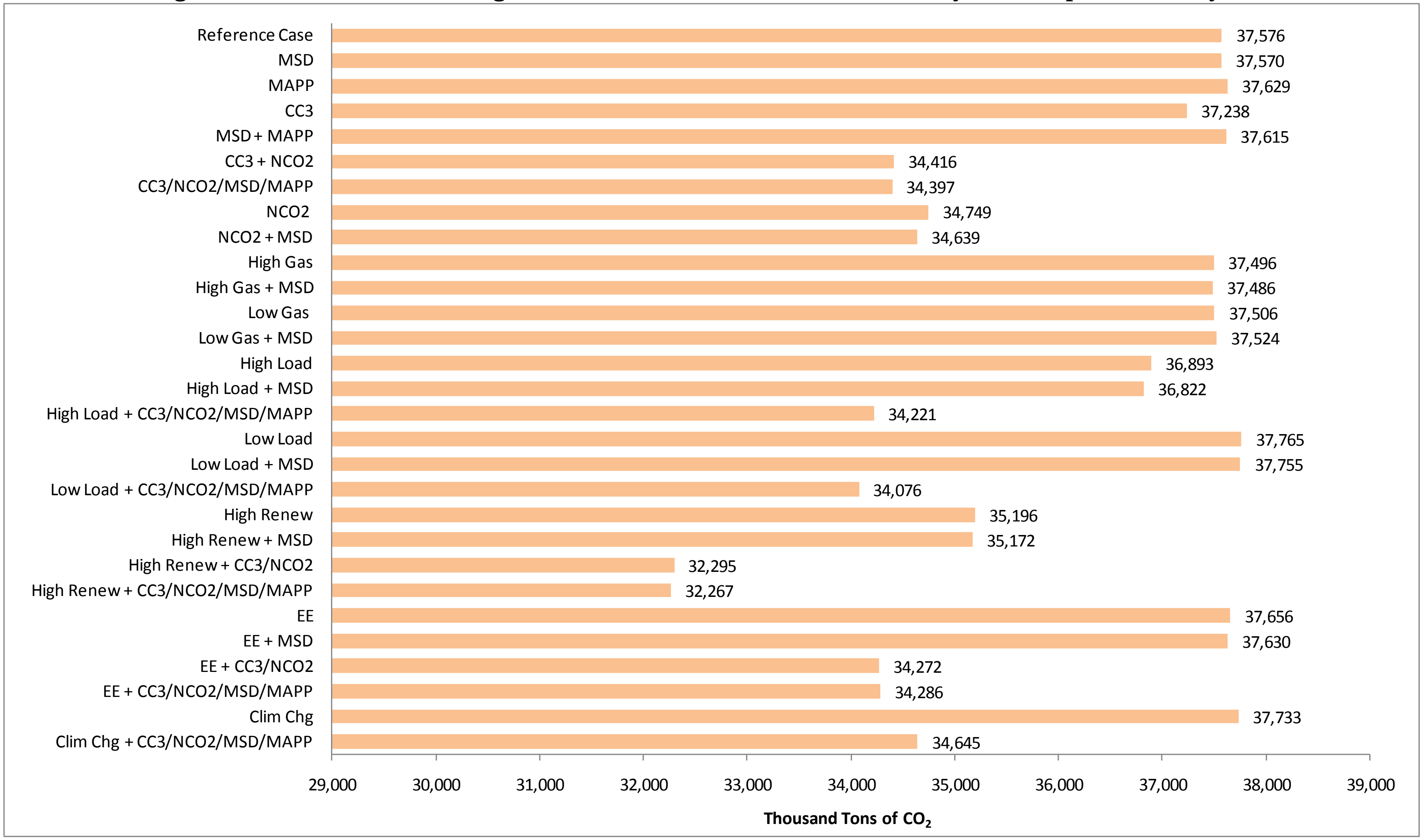


Figure 13.19 2010 Mercury Emissions from Electricity Consumption in Maryland

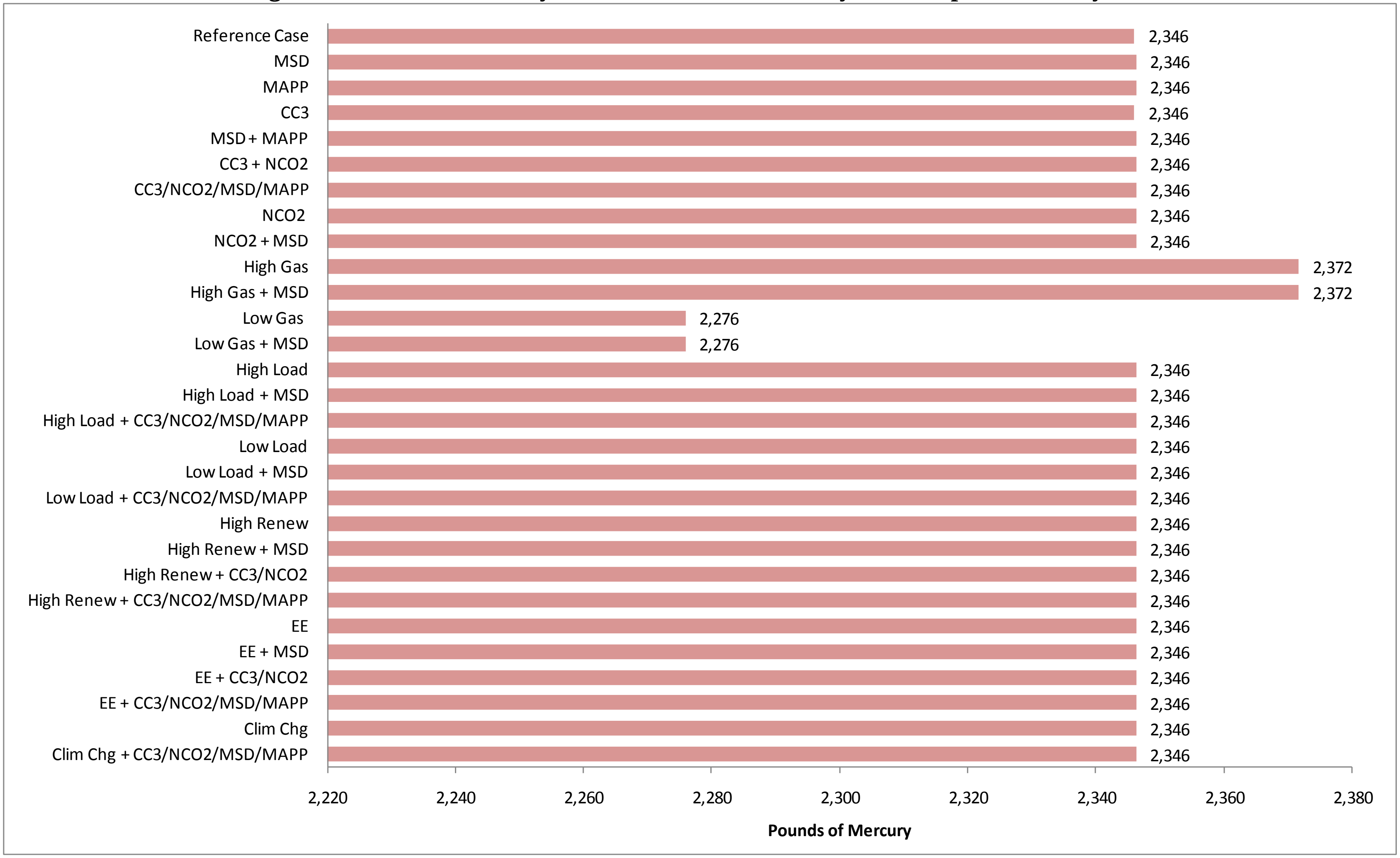


Figure 13.20 2020 Mercury Emissions from Electricity Consumption in Maryland

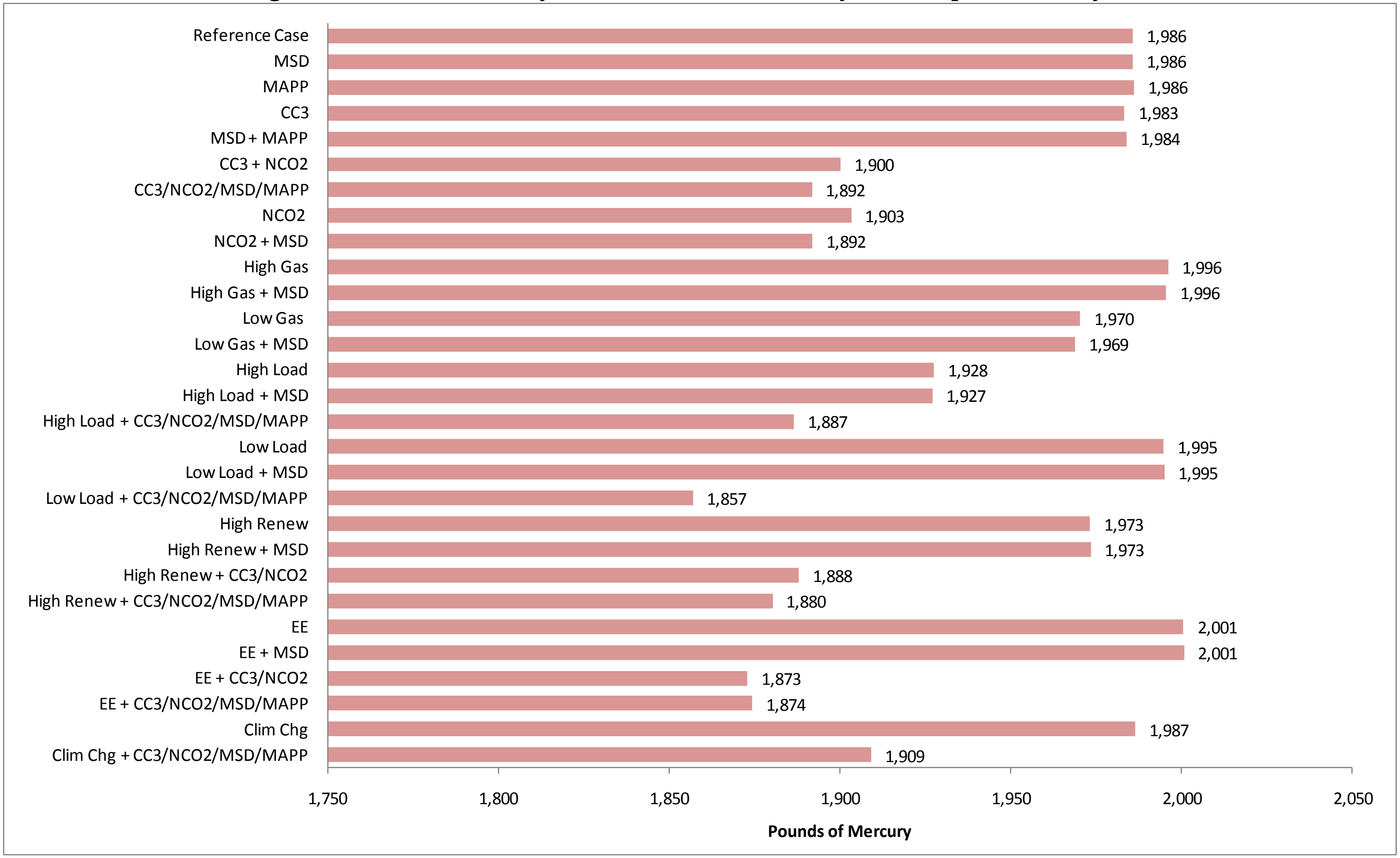


Figure 13.21 2030 Mercury Emissions from Electricity Consumption in Maryland

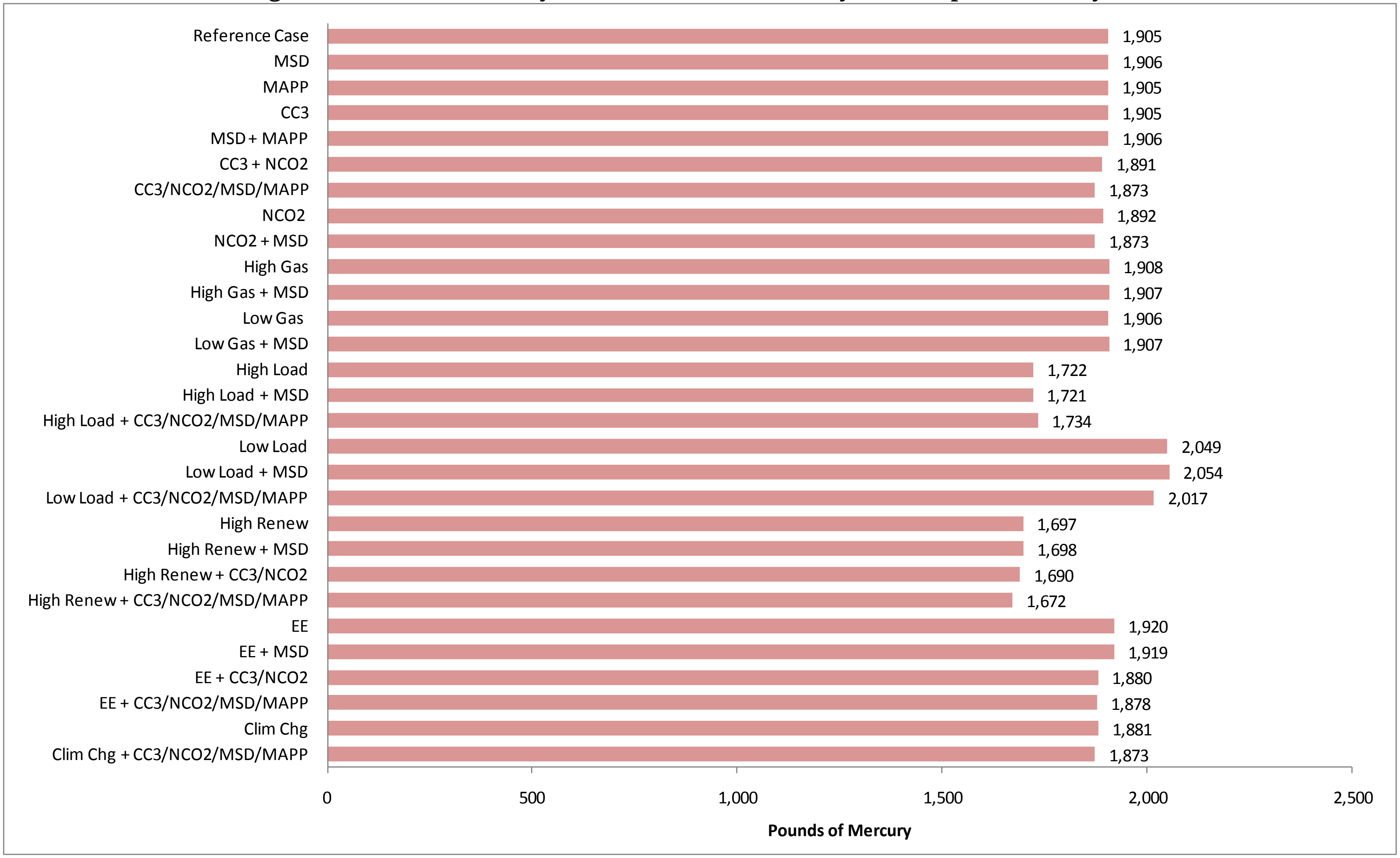


Figure 13.22 2010-2030 Avergae Annual Mercury Emissions from Electricity Consumption in Maryland

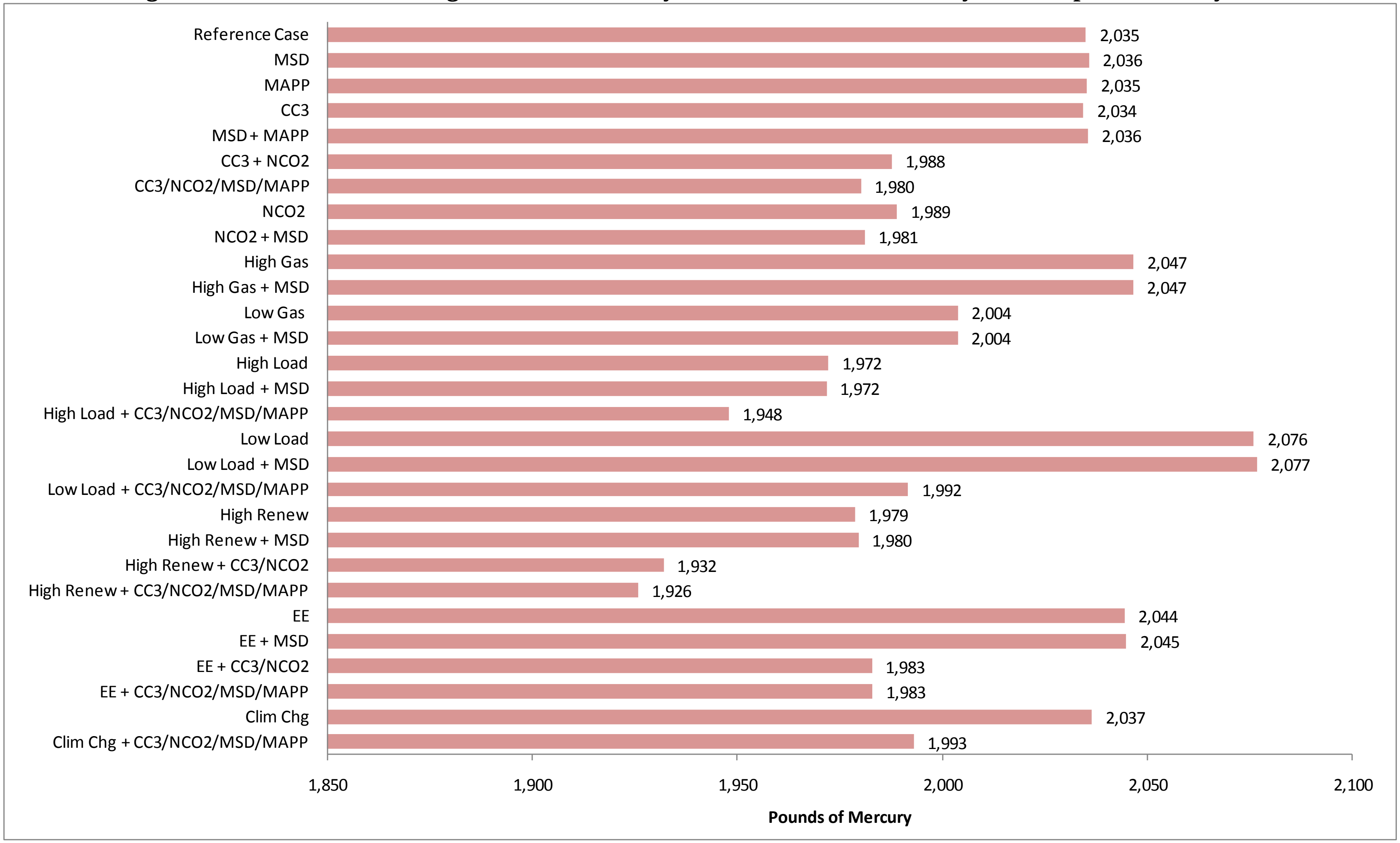


Figure 13.23 2010-2020 Average Annual Mercury Emissions from Electricity Consumption in Maryland

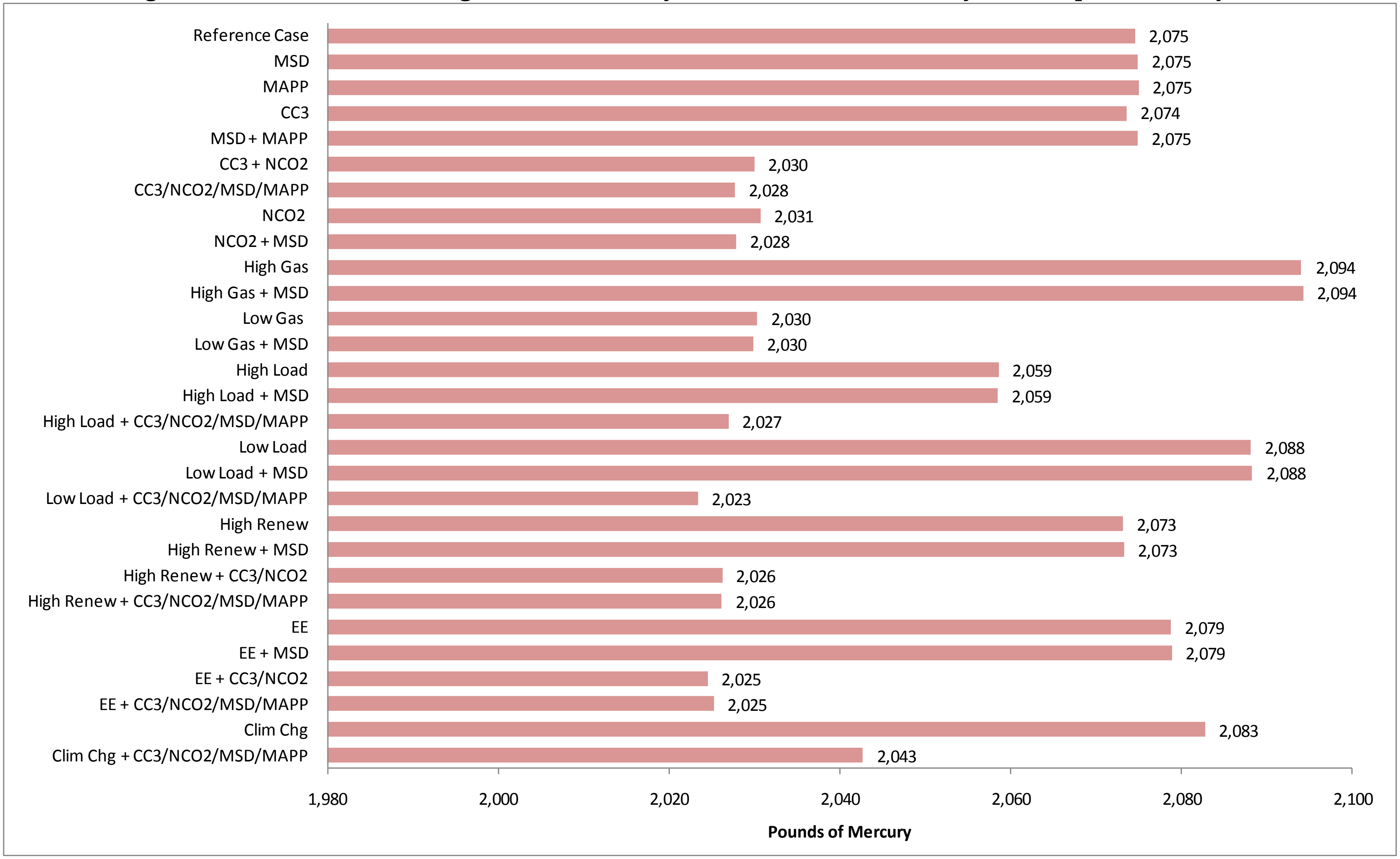
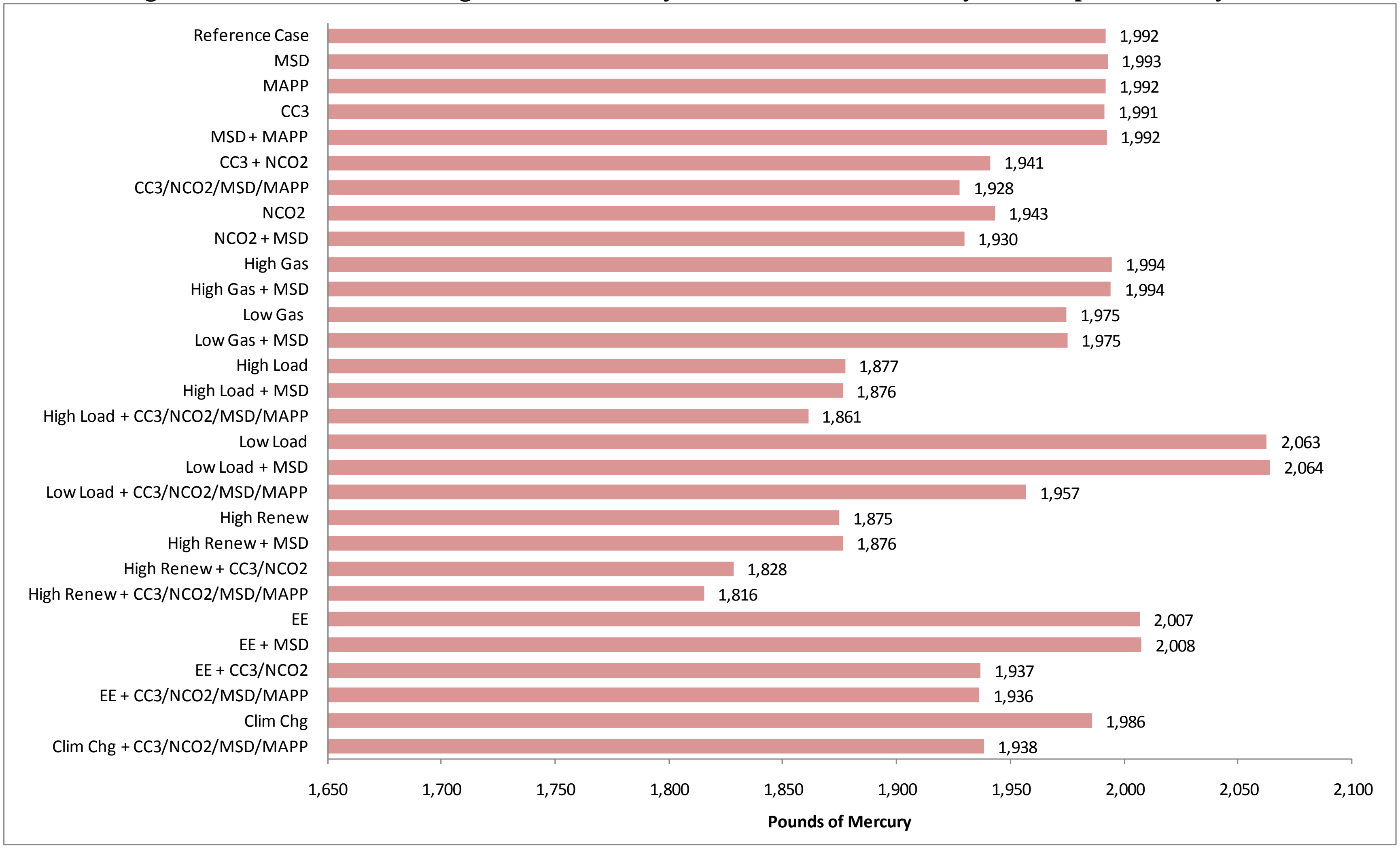


Figure 13.24 2021-2030 Average Annual Mercury Emissions from Electricity Consumption in Maryland



13.4.2 LTER Reference Case Results

Average annual SO_2 emissions in the LTER Reference Case is estimated to be approximately 45,000 tons for all electricity consumption in Maryland during the study period. This compares to annual average SO_2 emissions of about 34,000 tons from generating facilities in Maryland under the LTER Reference Case. We observe a similar difference for NO_x emissions. The average annual level of NO_x emissions is estimated to be approximately 27,000 tons from electricity consumption in Maryland, which compares to approximately 17,000 tons from electricity generation in Maryland during the study period.

These differences are consistent with Maryland being a net importer of electricity; however, the differences are magnified because of Maryland's Healthy Air Act. The HAA restricts SO_2 and NO_x emissions from large coal-burning power plants in the State over the entire study period; whereas the EPA's Clean Air Transport Rule ("CATR"), which restricts emissions of SO_2 and NO_x in all of PJM, does not come into effect until 2012. This explains why the estimated levels of SO_2 and NO_x emissions are highest in the earliest years of the study period (i.e., before the EPA's Clean Air Transport Rule comes into effect).

There is a smaller difference between CO_2 emissions from consumption and from generation than was the case for SO_2 and NO_x, which is primarily due to the higher use of coal in Maryland (as a percentage of total generation), compared to PJM as a whole. The average annual level of CO_2 emissions associated with electricity consumption in Maryland is approximately 37,000,000 tons during the study period. This level compares to an annual average of approximately 32,000,000 tons of CO_2 from electricity generated in Maryland between 2010 and 2030.

Estimated mercury emissions for Maryland consumption compared to Maryland generation shows a more significant difference relative to SO_2, NO_x, and CO_2 emissions. Annual average emissions of mercury are about 2,000 pounds from electricity consumption in Maryland during the study period. This level compares to annual average mercury emissions of approximately 200 pounds from electricity generation in the State. This difference is also explained by the HAA, because the HAA requires mercury emissions in Maryland to be reduced by 90 percent (relative to 2002 levels), while the CATR does not place any restrictions on mercury emissions.

13.4.3 Alternative Transmission Scenarios

In each of the alternative transmission scenarios (RC+MSD, RC+MAPP, RC+MSD+MAPP), we observe relatively little change from the LTER Reference Case results. This is expected because the development of these transmission lines has little impact on emissions in PJM as a whole.

13.4.4 High Renewables Scenarios and National Carbon Legislation Scenarios

In each scenario that includes high renewables or national carbon legislation, we see reduced consumption-based levels of each of the four pollutants relative to the LTER Reference Case. The scenarios that include high renewables result in relatively consistent reductions among all four pollutants. The greatest reductions in consumption-based CO_2 emissions are under the scenarios that include national carbon legislation. Because the national carbon legislation scenarios (which include a national RPS) result in increases in natural gas-fired capacity additions relative to the LTER Reference Case, SO_2, NO_x, and mercury are reduced because natural gas plants emit less of each pollutant compared to coal plants. In the two scenarios that include both high renewables and national carbon legislation, the results indicate that this combination will induce the greatest reductions in consumption-based emissions of all four pollutants.

13.4.5 Calvert Cliffs 3 Scenarios

Calvert Cliffs 3 coming on-line in 2019 results in small reductions in emissions of each pollutant (see 2020 Emissions graphs). This result is due to the addition of 1,600 MW of nuclear capacity which represents only a small percentage of total PJM capacity and hence results in a relatively small reduction in PJM-wide emissions.

Note that by 2030, emissions under the Calvert Cliffs 3 scenario are very close to the emissions produced under the LTER Reference Case. This outcome is due to the reduced level of natural gas capacity additions by 2030 (relative to those under the LTER Reference Case assumptions) if a third nuclear unit is constructed at the Calvert Cliffs site.

13.4.6 High and Low Natural Gas Price Scenarios

With higher natural gas prices, relatively less electricity will be derived from natural gas and a greater percentage will come from coal. Therefore, with high gas prices, emissions of each pollutant are higher than in the LTER Reference Case. With low natural gas prices, relatively more electricity is generated using gas, and hence lower emissions result.

It is important to note that the model does not capture the impacts associated with the price elasticity of demand. The price elasticity of demand measures the percentage change in the quantity demanded for a given percentage change in price (if electricity prices increase, consumers will consume less). Because the model does not capture price elasticity effects, the emissions levels are slightly overstated in the high natural gas price scenarios and slightly understated in the low gas price scenarios. This is because in the high natural gas price scenarios, electricity prices are higher than in the LTER Reference Case and, as a result, consumption (and therefore emissions) would be lower. With low natural gas prices, electricity prices are lower than in the LTER Reference Case and hence consumption (and emissions) would be higher.

13.4.7 Energy Efficiency Scenarios

The Aggressive Energy Efficiency scenario results in a small increase in the emissions levels of all four pollutants because the energy efficiency and conservation assumptions result in a slightly higher mix of coal plants relative to natural gas plants in PJM. Thus, the reduction in load is offset by emissions from plants with higher emissions rates. This result, however, is, in part, due to the length of the study period. If the study period were extended to a point where inefficient natural gas plants were retired, and new, more efficient plants represented all (or almost all) of the natural gas generation portfolios, lower loads resulting from energy efficiency programs would induce lower levels of emissions.

13.4.8 Climate Change Scenarios

The climate change scenario results in only very minor changes to emissions relative to the LTER Reference Case. The reason why the differences are minor is that the climate change scenario does not result in significant changes to annual energy consumption. The higher levels of consumption in the summer period are offset by reductions in consumption during the winter months.

13.4.9 High and Low Load Growth Scenarios

The estimated level of consumption-based emissions associated with the high and low load growth scenarios are dependent, in part, on the pace of capacity additions relative to the LTER Reference Case. In the high load growth scenarios, the natural gas capacity additions are greater than in the LTER Reference Case, which increases the portion of the generation portfolio composed of new, efficient power plants. More energy is consumed in the high load growth scenarios, however, and therefore, the plants must generate more. The opposite is true for the low load growth scenarios – the model builds less new natural gas capacity in comparison to the LTER Reference Case, but less energy is consumed, and though the average plant is less efficient, the plants run less.

Natural gas plants emit significantly less SO_2 than coal plants. In the low load growth scenario, the model builds relatively few new natural gas plants, but less energy is consumed overall. On balance there is a significant decrease in consumption-based SO_2 emissions. In the high load growth scenario, the additional load results in substantially more new natural gas plants being constructed than in the LTER Reference Case, but the higher levels of electricity being consumed in Maryland off-sets the increased efficiency and there is almost no change in emissions when compared to the LTER Reference Case.

Natural gas plants emit less NO_x and CO_2 than coal plants, but the difference is not as significant as with SO_2. Therefore, in the low load growth scenario the model builds less capacity and we observe almost no change in NO_x or CO_2 emissions. Under the high load growth scenario, the level of NO_x and CO_2 emissions is lower when compared to the LTER Reference Case.

Since natural gas plants emit no mercury, there are large reductions in mercury emissions as more natural gas capacity is added to PJM. This means that under the high load growth scenario, there are significant reductions in mercury emissions and for the low load growth scenario, there is an increase (though small) in mercury emissions.

13.4.10 Emissions Tables

Table 13.7 through Table 13.10 show the estimated levels of emissions from electricity consumption in Maryland for each pollutant, for each year, for each of the LTER scenarios.

Table 13.7 Annual SO_2 Emissions from Electricity Consumption in Maryland (tons)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Reference Case	119,533	102,300	79,100	54,704	46,284	35,771	33,807	32,899	32,222	31,765	32,035
MSD	119,533	102,304	79,092	54,742	46,323	37,035	34,855	34,273	33,578	33,297	33,489
MAPP	119,533	102,312	79,121	54,751	46,345	35,577	33,740	32,130	31,383	30,707	31,133
CC3	119,533	102,312	79,121	54,751	46,345	35,552	33,689	32,131	31,322	30,495	30,898
MSD + MAPP	119,533	102,311	79,106	54,782	46,380	36,856	34,417	33,527	32,774	32,734	33,397
CC3 + NCO2	119,533	102,311	79,106	54,782	46,380	36,843	34,402	33,525	32,766	32,737	33,400
CC3/NCO2/MSD/MAPP	119,533	102,300	79,102	54,704	46,295	35,526	33,651	32,142	31,545	31,107	31,457
NCO2	119,533	102,300	79,102	54,704	46,295	35,500	33,590	32,141	31,197	30,606	31,258
NCO2 + MSD	119,533	102,302	79,094	54,745	46,335	36,836	34,330	33,410	33,014	32,851	32,972
High Gas	122,120	102,302	79,094	54,745	46,335	36,823	34,314	33,410	33,008	32,841	32,974
High Gas + MSD	122,120	102,201	78,630	54,233	45,821	35,418	33,395	31,568	31,002	30,155	30,426
Low Gas	112,125	102,196	78,630	54,290	45,831	36,713	34,137	33,255	32,367	31,645	31,923
Low Gas + MSD	112,125	102,196	78,630	54,290	45,831	36,712	34,135	33,255	32,377	31,634	31,926
High Load	119,533	102,347	79,362	54,916	46,609	35,885	34,201	33,468	32,551	31,901	32,178
High Load + MSD	119,533	102,343	79,322	55,021	46,714	37,613	35,101	34,853	33,765	33,151	33,184
High Load + CC3/NCO2/MSD/MAPP	119,533	102,343	79,322	55,021	46,714	37,596	35,079	34,853	33,775	33,161	33,206
Low Load	119,533	96,432	72,815	50,476	43,350	35,219	33,389	32,931	32,371	31,904	32,674
Low Load + MSD	119,533	96,432	72,815	50,476	43,350	35,206	33,378	32,927	32,372	31,965	32,863
Low Load + CC3/NCO2/MSD/MAPP	119,533	103,725	81,049	56,195	47,173	37,413	34,623	33,780	33,416	33,467	33,867
High Renew	119,533	103,725	81,049	56,195	47,173	37,403	34,602	33,776	33,439	33,495	33,908
High Renew + MSD	119,533	102,300	79,102	54,704	46,295	35,526	33,651	32,142	31,489	31,465	31,925
High Renew + CC3/NCO2	119,533	102,300	79,102	54,704	46,295	35,500	33,590	32,141	31,469	31,242	31,928
High Renew + CC3/NCO2/MSD/MAPP	119,533	102,300	79,102	54,704	46,295	35,526	33,651	32,142	31,547	31,196	31,657
EE	119,533	102,300	79,102	54,704	46,295	35,500	33,590	32,141	31,469	31,052	31,498
EE + MSD	119,533	102,302	79,094	54,745	46,335	36,836	34,330	33,410	33,064	32,993	33,159
EE + CC3/NCO2	119,533	102,299	79,091	54,743	46,333	36,821	34,311	33,408	33,003	32,429	32,997
EE + CC3/NCO2/MSD/MAPP	119,533	102,302	79,094	54,745	46,335	36,823	34,314	33,410	33,044	32,983	33,445
Climate Chg	119,533	102,302	79,094	54,745	46,335	36,836	34,330	33,410	33,009	32,953	33,407
Climate Chg + CC3/NCO2/MSD/MAPP	119,533	102,299	79,091	54,743	46,333	36,821	34,311	33,408	33,003	32,942	33,411

Table 13.7 (cont.) Annual SO_2 Emissions from Electricity Consumption in Maryland (tons)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2010-2020 Average Annual Emissions	2021-2030 Average Annual Emissions	2010-2030 Average Annual Emissions	2010-2030 Cumulative Emissions
Reference Case	32,463	32,297	32,470	32,965	32,444	32,596	32,135	32,515	31,214	30,990	54,584	32,209	43,929	922,500
MSD	33,876	33,552	33,708	34,403	33,922	33,563	32,865	32,577	31,267	31,393	55,320	33,113	43,697	917,600
MAPP	31,779	32,307	32,517	32,973	32,617	32,676	32,482	32,749	31,403	31,351	54,249	32,285	44,615	936,900
CC3	31,619	31,871	32,363	32,826	32,530	32,592	32,266	32,643	31,428	31,352	54,195	32,149	44,745	939,600
MSD + MAPP	33,766	33,844	33,963	34,274	33,603	33,175	32,806	32,657	31,336	31,670	55,074	33,109	43,790	919,600
CC3 + NCO2	33,771	33,852	33,982	34,307	33,644	33,283	32,593	32,656	31,417	31,697	55,071	33,120	44,618	937,000
CC3/NCO2/MSD/MAPP	31,499	31,434	31,446	31,467	30,667	30,271	29,509	29,589	28,108	27,795	54,306	30,178	42,816	899,100
NCO2	31,394	31,291	31,371	31,396	30,578	30,299	29,561	29,648	28,178	27,885	54,202	30,160	42,754	897,800
NCO2 + MSD	33,230	33,010	32,781	32,692	31,665	30,909	30,150	29,861	28,172	28,037	55,038	31,051	43,616	915,900
High Gas	33,230	33,014	32,766	32,693	31,657	30,928	29,868	29,616	28,082	27,998	55,034	30,985	43,582	915,200
High Gas + MSD	30,827	30,732	30,967	31,536	31,606	32,207	32,466	33,056	32,324	33,293	53,853	31,901	43,400	911,400
Low Gas	32,354	32,076	32,360	32,882	32,834	33,057	33,106	33,016	31,624	32,263	54,593	32,557	44,100	926,100
Low Gas + MSD	32,361	32,077	32,366	32,891	32,850	32,924	33,021	32,992	31,603	32,260	54,593	32,534	44,089	925,900
High Load	32,375	32,318	32,349	32,900	32,332	32,315	31,607	31,594	29,855	29,152	54,814	31,680	43,798	919,700
High Load + MSD	33,496	33,334	33,626	33,871	33,280	32,831	31,930	31,576	29,720	29,237	55,509	32,290	44,452	933,500
High Load + CC3/NCO2/MSD/MAPP	33,702	33,588	33,632	33,928	33,401	32,873	31,929	31,584	29,758	29,237	55,509	32,363	44,487	934,200
Low Load	33,244	32,974	33,044	33,386	32,612	32,440	31,544	31,374	30,606	30,855	52,153	32,208	42,655	895,800
Low Load + MSD	33,243	33,004	33,098	33,417	32,630	32,511	31,497	31,332	30,589	30,785	52,173	32,211	42,667	896,000
Low Load + CC3/NCO2/MSD/MAPP	34,173	33,982	34,119	34,442	33,831	33,412	32,721	32,790	31,543	32,169	56,075	33,318	45,239	950,000
High Renew	34,170	34,001	34,116	34,460	33,839	33,427	32,758	32,874	31,665	32,299	56,081	33,361	45,262	950,500
High Renew + MSD	32,348	32,319	32,466	32,876	32,531	32,606	32,105	32,494	31,194	31,185	54,376	32,212	43,822	920,300
High Renew + CC3/NCO2	32,349	32,266	32,440	32,875	32,505	32,467	32,165	32,482	31,245	31,222	54,346	32,202	43,801	919,800
High Renew + CC3/NCO2/MSD/MAPP	32,030	32,190	32,466	32,885	32,417	32,313	31,919	32,300	31,121	31,144	54,332	32,078	43,735	918,400
EE	31,917	32,132	32,340	32,761	32,407	32,414	32,063	32,234	31,179	31,226	54,289	32,067	43,707	917,900
EE + MSD	33,780	33,586	33,680	34,021	33,409	33,020	32,626	32,516	31,232	31,462	55,073	32,933	44,530	935,100
EE + CC3/NCO2	33,411	33,533	33,629	33,938	33,315	32,905	32,500	32,571	31,229	31,463	54,997	32,849	44,451	933,500
EE + CC3/NCO2/MSD/MAPP	33,793	33,581	33,693	34,021	33,390	33,009	32,607	32,466	31,189	31,444	55,093	32,919	44,534	935,200
Climate Chg	33,780	33,575	33,766	34,006	33,409	33,012	32,642	32,758	31,280	31,500	55,087	32,973	44,556	935,700
Climate Chg + CC3/NCO2/MSD/MAPP	33,780	33,580	33,702	34,047	33,423	33,040	32,620	32,479	31,191	31,460	55,081	32,932	44,534	935,200

Table 13.8 Annual NO_x Emissions from Electricity Consumption in Maryland (tons)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Reference Case	37,845	35,383	32,306	28,053	26,950	26,360	25,458	25,233	24,760	24,369	24,483
MSD	37,845	35,383	32,302	28,069	26,964	27,057	26,215	26,116	25,704	25,485	25,649
MAPP	37,845	35,383	32,313	28,063	26,969	26,293	25,344	24,912	24,346	23,760	23,938
CC3	37,845	35,383	32,313	28,063	26,969	26,275	25,306	24,905	24,267	23,623	23,767
MSD + MAPP	37,845	35,383	32,309	28,075	26,982	26,991	26,057	26,011	25,657	25,528	25,830
CC3 + NCO2	37,845	35,383	32,309	28,075	26,982	26,988	26,056	26,012	25,656	25,532	25,833
CC3/NCO2/MSD/MAPP	37,845	35,383	32,307	28,053	26,954	26,273	25,317	24,897	24,417	23,991	24,066
NCO2	37,845	35,383	32,307	28,053	26,954	26,259	25,278	24,886	24,344	23,925	24,064
NCO2 + MSD	37,845	35,383	32,302	28,069	26,969	26,979	26,022	25,957	25,687	25,382	25,541
High Gas	38,558	35,383	32,302	28,069	26,969	26,975	26,021	25,962	25,687	25,387	25,545
High Gas + MSD	38,558	35,332	32,179	27,912	26,863	26,221	25,254	24,410	23,922	23,426	23,392
Low Gas	36,042	35,332	32,176	27,930	26,868	26,998	26,120	26,045	25,604	25,276	25,572
Low Gas + MSD	36,042	35,332	32,176	27,930	26,868	26,999	26,121	26,046	25,605	25,272	25,574
High Load	37,845	35,421	32,384	28,119	27,046	26,339	25,467	25,283	24,713	24,316	24,374
High Load + MSD	37,845	35,420	32,372	28,153	27,081	27,117	26,157	26,091	25,431	25,077	25,075
High Load + CC3/NCO2/MSD/MAPP	37,845	35,420	32,372	28,153	27,081	27,115	26,159	26,096	25,457	25,064	25,091
Low Load	37,845	33,877	30,851	26,916	26,149	26,496	25,726	25,812	25,500	25,281	25,637
Low Load + MSD	37,845	33,877	30,851	26,916	26,149	26,494	25,723	25,813	25,504	25,312	25,684
Low Load + CC3/NCO2/MSD/MAPP	37,845	35,758	32,854	28,499	27,260	27,087	26,102	26,067	25,696	25,604	25,801
High Renew	37,845	35,758	32,854	28,499	27,260	27,087	26,099	26,068	25,715	25,623	25,824
High Renew + MSD	37,845	35,383	32,307	28,053	26,954	26,273	25,317	24,897	24,377	24,177	24,407
High Renew + CC3/NCO2	37,845	35,383	32,307	28,053	26,954	26,259	25,278	24,886	24,447	24,210	24,494
High Renew + CC3/NCO2/MSD/MAPP	37,845	35,383	32,307	28,053	26,954	26,273	25,317	24,897	24,417	24,063	24,221
EE	37,845	35,383	32,307	28,053	26,954	26,259	25,278	24,886	24,447	24,041	24,209
EE + MSD	37,845	35,383	32,302	28,069	26,969	26,979	26,022	25,957	25,710	25,486	25,680
EE + CC3/NCO2	37,845	35,383	32,303	28,071	26,969	26,975	26,021	25,962	25,685	25,315	25,510
EE + CC3/NCO2/MSD/MAPP	37,845	35,383	32,302	28,069	26,969	26,975	26,021	25,962	25,709	25,490	25,746
Climate Chg	37,845	35,383	32,302	28,069	26,969	26,979	26,022	25,957	25,685	25,463	25,727
Climate Chg + CC3/NCO2/MSD/MAPP	37,845	35,383	32,303	28,071	26,969	26,975	26,021	25,962	25,685	25,468	25,734

Table 13.8 (cont.) Annual NO_x Emissions from Electricity Consumption in Maryland (tons)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2010-2020 Average Annual Emissions	2021-2030 Average Annual Emissions	2010-2030 Average Annual Emissions	2010-2030 Cumulative Emissions
Reference Case	24,695	24,548	24,723	25,006	24,943	25,273	25,173	24,889	24,259	23,849	28,291	24,736	26,598	558,600
MSD	25,734	25,540	25,721	26,079	26,052	26,074	25,766	25,122	24,219	23,887	28,799	25,419	27,190	571,000
MAPP	24,219	24,250	24,450	24,725	24,690	24,929	24,907	24,591	23,872	23,446	28,106	24,408	26,345	553,200
CC3	24,105	24,072	24,375	24,664	24,663	24,890	24,814	24,551	23,902	23,467	28,065	24,351	26,296	552,200
MSD + MAPP	25,936	25,799	25,984	26,164	26,050	26,032	25,860	25,313	24,417	24,132	28,788	25,569	27,255	572,400
CC3 + NCO2	25,923	25,794	25,979	26,177	26,101	26,054	25,742	25,287	24,430	24,154	28,788	25,564	27,253	572,300
CC3/NCO2/MSD/MAPP	23,974	23,880	23,843	23,795	23,447	23,367	22,949	22,475	21,678	21,077	28,137	23,048	25,714	540,000
NCO2	23,994	23,889	23,896	23,839	23,505	23,467	23,070	22,598	21,816	21,229	28,118	23,130	25,743	540,600
NCO2 + MSD	25,369	25,174	25,065	24,934	24,543	24,203	23,710	22,978	21,872	21,348	28,740	23,920	26,444	555,300
High Gas	25,373	25,164	25,046	24,922	24,531	24,204	23,580	22,933	21,830	21,316	28,740	23,890	26,431	555,000
High Gas + MSD	23,556	23,568	23,861	24,219	24,442	24,878	24,973	24,840	24,365	24,375	27,887	24,308	26,182	549,800
Low Gas	25,770	25,668	25,990	26,356	26,533	26,699	26,650	26,160	25,382	25,201	28,706	26,041	27,437	576,200
Low Gas + MSD	25,774	25,667	25,991	26,361	26,543	26,716	26,631	26,157	25,386	25,242	28,706	26,047	27,440	576,200
High Load	24,387	24,301	24,445	24,657	24,520	24,650	24,422	24,027	23,136	22,530	28,301	24,107	26,304	552,400
High Load + MSD	25,117	24,966	25,129	25,227	25,080	24,961	24,566	23,902	22,867	22,354	28,711	24,417	26,666	560,000
High Load + CC3/NCO2/MSD/MAPP	25,186	25,041	25,114	25,266	25,105	24,961	24,558	23,920	22,901	22,370	28,714	24,442	26,680	560,300
Low Load	25,776	25,550	25,718	25,920	25,781	25,886	25,567	25,091	24,533	24,298	28,026	25,412	26,781	562,400
Low Load + MSD	25,752	25,553	25,726	25,942	25,826	25,976	25,604	25,104	24,517	24,257	28,033	25,426	26,792	562,600
Low Load + CC3/NCO2/MSD/MAPP	25,828	25,689	25,828	26,032	25,944	25,948	25,646	25,158	24,335	24,087	29,026	25,450	27,323	573,800
High Renew	25,856	25,684	25,818	26,038	25,959	25,957	25,659	25,193	24,394	24,142	29,031	25,470	27,335	574,000
High Renew + MSD	24,601	24,472	24,666	24,907	24,882	25,173	25,048	24,760	24,137	23,753	28,181	24,640	26,495	556,400
High Renew + CC3/NCO2	24,696	24,533	24,752	25,000	24,993	25,216	25,168	24,872	24,307	23,913	28,192	24,745	26,551	557,600
High Renew + CC3/NCO2/MSD/MAPP	24,386	24,356	24,553	24,815	24,783	24,976	24,836	24,619	24,060	23,678	28,157	24,506	26,419	554,800
EE	24,410	24,388	24,625	24,888	24,858	25,111	25,023	24,711	24,238	23,882	28,151	24,613	26,466	555,800
EE + MSD	25,812	25,624	25,773	25,976	25,930	25,889	25,700	25,209	24,317	24,040	28,764	25,427	27,175	570,700
EE + CC3/NCO2	25,637	25,538	25,710	25,893	25,846	25,785	25,586	25,106	24,228	23,942	28,731	25,327	27,110	569,300
EE + CC3/NCO2/MSD/MAPP	25,796	25,624	25,782	25,978	25,922	25,894	25,707	25,188	24,304	24,020	28,770	25,422	27,176	570,700
Climate Chg	25,810	25,622	25,835	25,983	25,923	25,899	25,726	25,222	24,314	24,035	28,764	25,437	27,179	570,800
Climate Chg + CC3/NCO2/MSD/MAPP	25,801	25,624	25,810	26,005	25,923	25,924	25,721	25,196	24,292	24,018	28,765	25,431	27,178	570,700

Table 13.9 Annual CO_2 Emissions from Electricity Consumption in Maryland (thousands of tons)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Reference Case	40,874	39,837	39,008	37,838	36,696	36,167	35,459	35,434	34,862	34,560	34,853
MSD	40,874	39,837	39,003	37,856	36,714	36,866	36,331	36,505	36,001	35,904	36,243
MAPP	40,874	39,837	39,016	37,856	36,724	36,070	35,378	35,254	34,605	34,116	34,475
CC3	40,874	39,837	39,016	37,856	36,724	36,058	35,351	35,252	34,547	33,996	34,332
MSD + MAPP	40,874	39,837	39,012	37,871	36,741	36,765	36,192	36,463	35,977	35,875	36,292
CC3 + NCO2	40,874	39,837	39,012	37,871	36,741	36,766	36,192	36,461	35,975	35,877	36,293
CC3/NCO2/MSD/MAPP	40,874	39,837	39,008	37,838	36,703	36,039	35,330	35,215	34,609	34,110	34,360
NCO2	40,874	39,837	39,008	37,838	36,703	36,029	35,301	35,212	34,550	34,022	34,300
NCO2 + MSD	40,874	39,837	39,003	37,856	36,720	36,741	36,137	36,370	35,952	35,648	35,917
High Gas	41,341	39,837	39,003	37,856	36,720	36,739	36,137	36,372	35,951	35,652	35,919
High Gas + MSD	41,341	39,809	38,949	37,812	36,749	36,145	35,422	34,998	34,466	33,939	34,149
Low Gas	39,575	39,809	38,947	37,833	36,751	36,991	36,407	36,717	36,074	35,703	36,195
Low Gas + MSD	39,575	39,809	38,947	37,833	36,751	36,993	36,411	36,717	36,072	35,696	36,197
High Load	40,874	39,848	39,025	37,775	36,629	36,070	35,402	35,458	34,889	34,494	34,839
High Load + MSD	40,874	39,848	39,018	37,824	36,676	36,782	36,192	36,479	35,805	35,621	35,856
High Load + CC3/NCO2/MSD/MAPP	40,874	39,848	39,018	37,824	36,676	36,782	36,195	36,482	35,793	35,644	35,874
Low Load	40,874	38,624	37,913	36,982	36,119	36,456	35,837	36,163	35,748	35,512	36,107
Low Load + MSD	40,874	38,624	37,913	36,982	36,119	36,456	35,835	36,162	35,751	35,562	36,147
Low Load + CC3/NCO2/MSD/MAPP	40,874	40,126	39,521	38,340	37,020	36,810	36,113	36,395	35,822	35,786	36,185
High Renew	40,874	40,126	39,521	38,340	37,020	36,811	36,112	36,395	35,837	35,799	36,205
High Renew + MSD	40,874	39,837	39,008	37,838	36,703	36,039	35,330	35,215	34,580	34,410	34,867
High Renew + CC3/NCO2	40,874	39,837	39,008	37,838	36,703	36,029	35,301	35,212	34,622	34,370	34,917
High Renew + CC3/NCO2/MSD/MAPP	40,874	39,837	39,008	37,838	36,703	36,039	35,330	35,215	34,610	34,214	34,580
EE	40,874	39,837	39,008	37,838	36,703	36,029	35,301	35,212	34,622	34,169	34,539
EE + MSD	40,874	39,837	39,003	37,856	36,720	36,741	36,137	36,370	35,976	35,790	36,174
EE + CC3/NCO2	40,874	39,837	39,003	37,856	36,720	36,739	36,137	36,372	35,949	35,584	35,847
EE + CC3/NCO2/MSD/MAPP	40,874	39,837	39,003	37,856	36,720	36,739	36,137	36,372	35,972	35,789	36,238
Climate Chg	40,874	39,837	39,003	37,856	36,720	36,741	36,137	36,370	35,949	35,760	36,213
Climate Chg + CC3/NCO2/MSD/MAPP	40,874	39,837	39,003	37,856	36,720	36,739	36,137	36,372	35,949	35,764	36,218

Table 13.9 (cont.) Annual CO_2 Emissions from Electricity Consumption in Maryland (thousands of tons)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2010-2020 Average Annual Emissions	2021-2030 Average Annual Emissions	2010-2030 Average Annual Emissions	2010-2030 Cumulative Emissions
Reference Case	35,114	35,140	35,708	36,412	36,640	35,067	35,471	33,565	32,509	30,822	36,872	34,645	35,811	752,000
MSD	36,584	36,588	37,047	37,669	37,851	38,184	38,344	38,304	38,457	38,307	37,467	37,733	37,594	789,500
MAPP	34,767	34,871	35,404	35,984	36,149	34,573	35,049	33,584	32,105	30,377	36,746	34,286	35,575	747,100
CC3	34,676	34,705	35,371	35,911	36,110	34,994	34,996	33,495	32,091	30,374	36,713	34,272	35,551	746,600
MSD + MAPP	36,518	36,566	37,034	37,490	37,579	37,953	38,201	38,260	38,406	38,297	37,445	37,630	37,533	788,200
CC3 + NCO2	36,504	36,570	37,099	37,533	37,670	37,976	38,189	38,232	38,459	38,332	37,445	37,656	37,546	788,500
CC3/NCO2/MSD/MAPP	34,192	34,159	34,325	34,424	34,127	32,720	32,274	30,449	28,941	27,062	36,720	32,267	34,600	726,600
NCO2	34,182	34,134	34,337	34,427	34,164	32,721	32,316	30,494	29,041	27,134	36,698	32,295	34,601	726,600
NCO2 + MSD	35,803	35,776	35,823	35,807	35,433	35,299	35,023	34,662	34,320	33,772	37,369	35,172	36,322	762,800
High Gas	35,804	35,767	35,847	35,837	35,462	35,324	35,040	34,684	34,368	33,823	37,369	35,196	36,334	763,000
High Gas + MSD	34,353	34,365	34,837	35,353	35,691	34,756	34,543	33,334	33,133	30,394	36,665	34,076	35,432	744,100
Low Gas	36,469	36,397	36,902	37,385	37,690	38,023	38,449	38,524	38,808	38,905	37,482	37,755	37,612	789,900
Low Gas + MSD	36,472	36,395	36,904	37,393	37,701	38,096	38,443	38,529	38,821	38,901	37,482	37,765	37,617	790,000
High Load	35,050	35,066	35,519	36,039	36,250	34,607	34,696	33,098	31,668	30,217	36,846	34,221	35,596	747,500
High Load + MSD	36,087	36,094	36,510	36,921	37,026	37,210	37,286	37,114	37,128	36,839	37,361	36,822	37,104	779,200
High Load + CC3/NCO2/MSD/MAPP	36,132	36,147	36,498	36,988	37,097	37,280	37,387	37,223	37,237	36,943	37,364	36,893	37,140	779,900
Low Load	36,427	36,389	36,767	37,346	37,377	37,905	38,051	38,105	38,492	38,383	36,821	37,524	37,156	780,300
Low Load + MSD	36,395	36,344	36,802	37,337	37,353	37,868	37,994	38,067	38,513	38,384	36,830	37,506	37,151	780,200
Low Load + CC3/NCO2/MSD/MAPP	36,449	36,455	36,911	37,379	37,457	37,777	38,009	38,049	38,251	38,121	37,587	37,486	37,539	788,300
High Renew	36,404	36,457	36,951	37,366	37,447	37,810	38,022	38,066	38,276	38,160	37,592	37,496	37,546	788,500
High Renew + MSD	35,186	35,293	35,796	36,375	36,520	34,904	35,344	33,677	32,476	30,822	36,791	34,639	35,766	751,100
High Renew + CC3/NCO2	35,235	35,237	35,842	36,426	36,575	35,419	35,423	33,770	32,629	30,932	36,792	34,749	35,819	752,200
High Renew + CC3/NCO2/MSD/MAPP	34,810	34,895	35,468	36,028	36,150	35,093	35,067	33,500	32,320	30,639	36,750	34,397	35,629	748,200
EE	34,801	34,891	35,449	36,001	36,190	35,128	35,124	33,505	32,363	30,708	36,739	34,416	35,633	748,300
EE + MSD	36,496	36,532	37,018	37,456	37,625	37,914	38,174	38,234	38,414	38,290	37,407	37,615	37,506	787,600
EE + CC3/NCO2	36,055	36,141	36,639	37,096	37,217	37,556	37,751	37,873	38,089	37,959	37,356	37,238	37,300	783,300
EE + CC3/NCO2/MSD/MAPP	36,524	36,492	37,036	37,517	37,618	37,915	38,172	38,247	38,448	38,325	37,412	37,629	37,516	787,800
Climate Chg	36,468	36,453	36,971	37,443	37,580	37,876	38,110	38,186	38,366	38,248	37,405	37,570	37,484	787,200
Climate Chg + CC3/NCO2/MSD/MAPP	36,464	36,425	36,955	37,458	37,533	37,902	38,146	38,202	38,388	38,288	37,406	37,576	37,487	787,200

Table 13.10 Annual Mercury Emissions from Electricity Consumption in Maryland (pounds)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Reference Case	2,346	2,270	2,173	2,087	2,014	1,972	1,953	1,948	1,906	1,892	1,909
MSD	2,346	2,270	2,172	2,089	2,016	2,033	2,013	2,026	1,986	1,973	1,987
MAPP	2,346	2,270	2,173	2,089	2,017	1,954	1,929	1,911	1,870	1,843	1,874
CC3	2,346	2,270	2,173	2,089	2,017	1,953	1,929	1,912	1,868	1,839	1,873
MSD + MAPP	2,346	2,270	2,173	2,091	2,019	2,016	1,990	2,005	1,978	1,980	2,001
CC3 + NCO2	2,346	2,270	2,173	2,091	2,019	2,016	1,990	2,005	1,977	1,980	2,001
CC3/NCO2/MSD/MAPP	2,346	2,270	2,173	2,087	2,015	1,950	1,924	1,911	1,876	1,857	1,880
NCO2	2,346	2,270	2,173	2,087	2,015	1,950	1,924	1,912	1,869	1,856	1,888
NCO2 + MSD	2,346	2,270	2,172	2,089	2,016	2,013	1,985	1,996	1,977	1,968	1,973
High Gas	2,372	2,270	2,172	2,089	2,016	2,013	1,984	1,996	1,977	1,968	1,973
High Gas + MSD	2,372	2,272	2,173	2,092	2,029	1,966	1,934	1,896	1,863	1,829	1,857
Low Gas	2,276	2,272	2,173	2,094	2,029	2,049	2,019	2,036	1,995	1,962	1,995
Low Gas + MSD	2,276	2,272	2,173	2,094	2,029	2,049	2,019	2,036	1,994	1,961	1,995
High Load	2,346	2,267	2,168	2,073	1,995	1,956	1,934	1,927	1,881	1,863	1,887
High Load + MSD	2,346	2,267	2,167	2,078	2,000	2,015	1,984	1,995	1,941	1,925	1,927
High Load + CC3/NCO2/MSD/MAPP	2,346	2,267	2,167	2,078	2,000	2,014	1,983	1,994	1,942	1,925	1,928
Low Load	2,346	2,208	2,091	2,025	1,972	1,990	1,950	1,969	1,951	1,929	1,969
Low Load + MSD	2,346	2,208	2,091	2,025	1,972	1,989	1,950	1,969	1,950	1,934	1,970
Low Load + CC3/NCO2/MSD/MAPP	2,346	2,285	2,219	2,136	2,043	2,030	1,991	2,007	1,978	1,982	1,996
High Renew	2,346	2,285	2,219	2,136	2,043	2,030	1,991	2,006	1,977	1,982	1,996
High Renew + MSD	2,346	2,270	2,173	2,087	2,015	1,950	1,924	1,911	1,875	1,864	1,892
High Renew + CC3/NCO2	2,346	2,270	2,173	2,087	2,015	1,950	1,924	1,912	1,885	1,874	1,903
High Renew + CC3/NCO2/MSD/MAPP	2,346	2,270	2,173	2,087	2,015	1,950	1,924	1,911	1,876	1,862	1,892
EE	2,346	2,270	2,173	2,087	2,015	1,950	1,924	1,912	1,885	1,869	1,900
EE + MSD	2,346	2,270	2,172	2,089	2,016	2,013	1,985	1,996	1,978	1,975	1,984
EE + CC3/NCO2	2,346	2,269	2,172	2,088	2,016	2,013	1,984	1,996	1,976	1,965	1,983
EE + CC3/NCO2/MSD/MAPP	2,346	2,270	2,172	2,089	2,016	2,013	1,984	1,996	1,978	1,975	1,986
Climate Chg	2,346	2,270	2,172	2,089	2,016	2,013	1,985	1,996	1,977	1,974	1,986
Climate Chg + CC3/NCO2/MSD/MAPP	2,346	2,269	2,172	2,088	2,016	2,013	1,984	1,996	1,976	1,973	1,986

Table 13.10 (cont.) Annual Mercury Emissions from Electricity Consumption in Maryland (pounds)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2010-2020 Average Annual Emissions	2021-2030 Average Annual Emissions	2010-2030 Average Annual Emissions	2010-2030 Cumulative Emissions
Reference Case	1,922	1,916	1,937	1,951	1,947	1,963	1,970	1,970	1,934	1,873	2,043	1,938	1,993	41,900
MSD	1,998	1,989	2,005	2,021	2,017	2,018	2,014	1,982	1,933	1,881	2,083	1,986	2,037	42,800
MAPP	1,903	1,909	1,928	1,947	1,947	1,964	1,978	1,975	1,937	1,878	2,025	1,936	1,983	41,600
CC3	1,901	1,908	1,928	1,947	1,948	1,967	1,974	1,975	1,941	1,880	2,025	1,937	1,983	41,600
MSD + MAPP	2,012	2,008	2,024	2,035	2,025	2,033	2,037	2,015	1,966	1,919	2,079	2,008	2,045	42,900
CC3 + NCO2	2,012	2,008	2,024	2,036	2,025	2,034	2,029	2,013	1,967	1,920	2,079	2,007	2,044	42,900
CC3/NCO2/MSD/MAPP	1,872	1,869	1,867	1,862	1,834	1,828	1,811	1,796	1,743	1,672	2,026	1,816	1,926	40,400
NCO2	1,881	1,879	1,878	1,874	1,846	1,842	1,825	1,810	1,760	1,690	2,026	1,828	1,932	40,600
NCO2 + MSD	1,965	1,957	1,953	1,939	1,904	1,891	1,869	1,829	1,760	1,698	2,073	1,876	1,980	41,600
High Gas	1,965	1,957	1,953	1,938	1,903	1,891	1,860	1,825	1,759	1,697	2,073	1,875	1,979	41,600
High Gas + MSD	1,865	1,867	1,897	1,918	1,952	1,989	2,008	2,026	2,029	2,017	2,023	1,957	1,992	41,800
Low Gas	2,006	2,007	2,041	2,062	2,078	2,100	2,117	2,100	2,075	2,054	2,088	2,064	2,077	43,600
Low Gas + MSD	2,005	2,006	2,041	2,062	2,079	2,094	2,115	2,100	2,074	2,049	2,088	2,063	2,076	43,600
High Load	1,889	1,878	1,888	1,902	1,887	1,888	1,881	1,861	1,804	1,734	2,027	1,861	1,948	40,900
High Load + MSD	1,931	1,918	1,927	1,929	1,914	1,903	1,885	1,848	1,787	1,721	2,059	1,876	1,972	41,400
High Load + CC3/NCO2/MSD/MAPP	1,932	1,921	1,927	1,930	1,916	1,903	1,885	1,849	1,788	1,722	2,059	1,877	1,972	41,400
Low Load	1,983	1,973	1,985	2,000	1,978	2,004	1,995	1,973	1,953	1,907	2,030	1,975	2,004	42,100
Low Load + MSD	1,982	1,973	1,988	2,000	1,979	2,005	1,991	1,971	1,952	1,906	2,030	1,975	2,004	42,100
Low Load + CC3/NCO2/MSD/MAPP	2,002	1,996	2,013	2,025	2,012	2,020	2,015	1,998	1,953	1,907	2,094	1,994	2,047	43,000
High Renew	2,002	1,996	2,012	2,025	2,012	2,020	2,016	1,998	1,955	1,908	2,094	1,994	2,047	43,000
High Renew + MSD	1,902	1,904	1,920	1,939	1,939	1,957	1,964	1,966	1,932	1,873	2,028	1,930	1,981	41,600
High Renew + CC3/NCO2	1,914	1,915	1,932	1,952	1,951	1,968	1,978	1,980	1,949	1,892	2,031	1,943	1,989	41,800
High Renew + CC3/NCO2/MSD/MAPP	1,902	1,897	1,926	1,944	1,934	1,952	1,960	1,961	1,930	1,873	2,028	1,928	1,980	41,600
EE	1,912	1,913	1,932	1,950	1,950	1,969	1,977	1,971	1,948	1,891	2,030	1,941	1,988	41,700
EE + MSD	1,997	1,992	2,008	2,019	2,010	2,018	2,021	2,001	1,953	1,906	2,075	1,992	2,036	42,700
EE + CC3/NCO2	1,996	1,991	2,007	2,018	2,008	2,017	2,019	2,000	1,952	1,905	2,074	1,991	2,034	42,700
EE + CC3/NCO2/MSD/MAPP	1,997	1,991	2,007	2,019	2,009	2,017	2,021	1,999	1,952	1,905	2,075	1,992	2,035	42,700
Climate Chg	1,997	1,992	2,009	2,019	2,009	2,018	2,022	2,002	1,952	1,906	2,075	1,993	2,036	42,800
Climate Chg + CC3/NCO2/MSD/MAPP	1,997	1,991	2,008	2,019	2,009	2,017	2,020	1,999	1,952	1,905	2,075	1,992	2,035	42,700

13.5 Price Variability

Pursuant to the EO, this report considers how each of the scenarios affects price variability in Maryland. This section addresses three types of energy price variability: (1) price changes over time; (2) on-peak and off-peak price differentials; and (3) seasonal price differentials. The hourly variability in wholesale electricity prices is not considered since almost all end-use electricity consumers purchase electricity under arrangements that entail fixed energy prices.

13.5.1 Price Changes Over Time

The all-hours wholesale energy prices in the LTER Reference Case and the alternative scenarios exhibit the same general pattern, with steady growth in the first ten years of the study period (2010-2020) followed by much slower growth, and in some cases negative growth, in the second half of the study period (2020-2030). Table 13.11 presents the compound average annual growth rates of the annual average all-hours energy price for the first and second half of the study period and the study period as a whole. For example, in the LTER Reference Case, the real PJM-SW all-hours energy price is projected to grow at an average annual growth rate of 4.5 percent between 2010 and 2020 with average annual growth slowing to 0.07 percent between 2020 and 2030. Real all-hours prices in PJM-MidE and APS follow the same general pattern, with faster growth in the first ten years of the study period and much slower growth in the second half.

The asymmetric growth pattern over the 2010 through 2030 study period is largely the result of diminishing excess generating capacity over the 2010 through 2020 period. As the initial capacity surpluses in PJM erodes, less efficient plants are dispatched to meet energy demand requirements. Prices begin to stabilize, and in some cases decrease, once demand growth is matched by the construction of new, more efficient natural gas capacity.

Table 13.11
Price Variability: Compound Average Annual Growth Rates of All-Hours Wholesale Energy Prices (%)

Scenario	PJM-SW			PJM-MidE			PJM-APS		
	2010 to 2020	2020 to 2030	2010 to 2030	2010 to 2020	2020 to 2030	2010 to 2030	2010 to 2020	2020 to 2030	2010 to 2030
Reference Case	4.50	0.17	2.31	4.15	0.32	2.22	4.71	0.24	2.45
MSD	4.32	0.20	2.24	4.17	0.34	2.24	4.88	0.17	2.50
MAPP	4.47	0.27	2.34	4.23	0.25	2.22	4.79	0.17	2.46
CC3	3.93	0.69	2.30	4.14	0.35	2.22	4.42	0.54	2.46
MAPP+ MSD	4.42	0.28	2.33	4.23	0.27	2.23	4.92	0.18	2.52
CC3 + NCO2	4.99	2.31	3.64	5.43	1.77	3.58	5.50	2.46	3.97
CC3 + NCO2/MSD/MAPP	5.29	2.07	3.67	5.33	1.75	3.52	5.78	2.22	3.99
NCO2	5.44	1.90	3.66	5.55	1.60	3.55	5.83	2.15	3.97
NCO2 + MSD	5.39	1.96	3.66	5.57	1.61	3.57	5.94	2.09	4.00
High Gas	5.60	0.93	3.24	5.12	0.98	3.03	6.12	1.14	3.60
High Gas + MSD	5.44	0.94	3.16	5.12	0.97	3.03	6.21	1.07	3.61
Low Gas	2.97	-0.87	1.03	2.74	-0.53	1.09	2.97	-0.92	1.01
Low Gas + MSD	2.95	-0.92	0.99	2.77	-0.48	1.14	3.26	-1.04	1.09
High Loads	4.15	0.41	2.26	3.86	0.54	2.19	4.58	0.22	2.38
High Load + MSD	4.08	0.38	2.21	3.89	0.55	2.21	4.68	0.23	2.43
High Load + CC3/NCO2/MSD/ MAPP	5.40	1.87	3.62	5.27	1.78	3.51	5.98	1.93	3.94
Low Loads	3.35	1.64	2.49	3.76	1.05	2.40	3.61	1.82	2.71
Low Load + MSD	3.20	1.62	2.40	3.75	0.96	2.35	3.75	1.70	2.72
Low Load + CC3/NCO2/MSD/ MAPP	4.48	3.10	3.79	4.78	2.58	3.67	4.91	3.28	4.09
High Renewables	4.63	0.07	2.33	4.20	0.15	2.15	4.72	0.21	2.44
High Renew + MSD	4.40	0.13	2.24	4.22	0.27	2.23	4.94	0.10	2.49
High Renew + CC3 + NCO2	5.01	2.25	3.62	5.49	1.58	3.52	5.54	2.40	3.96
High Renew + CC3/NCO2/MSD/ MAPP	5.28	2.05	3.65	5.32	1.72	3.51	5.77	2.21	3.98
EE	4.21	0.43	2.30	4.16	0.34	2.23	4.61	0.38	2.47
EE + MSD	4.12	0.31	2.20	4.16	0.37	2.24	4.68	0.36	2.50
EE + CC3 + NCO2	4.84	2.42	3.62	5.49	1.67	3.56	5.38	2.60	3.98
EE + CC3/NCO2/MSD/ MAPP	5.25	2.14	3.68	5.38	1.75	3.55	5.73	2.30	4.00
Climate Change	4.28	0.29	2.27	4.00	0.48	2.23	4.60	0.28	2.42
Climate Change + CC3/NCO2/MSD/ MAPP	5.20	2.10	3.64	5.25	1.80	3.51	5.71	2.24	3.96

All-hours prices grow at an average annual rate of 2.31 percent in PJM-SW over the 2010-2030 period, compared with 2.22 percent and 2.45 percent for PJM-MidE and PJM-APS, respectively. Energy prices tend to increase faster in the PJM-APS zone compared to the PJM-SW and PJM-MidE zones because 2010 PJM-APS prices were the lowest of the three Maryland regions, given the ample coal capacity in PJM-APS. Thus, prices rise more sharply in the PJM-APS zone over time, as natural gas increasingly becomes the marginal fuel and some of the zone's coal capacity retires.

Conditions of low load growth and the implementation of national carbon legislation result in the steepest price increases over the study period. Introducing national carbon legislation causes the average growth rate of wholesale prices to rise by at least one percentage point per year over the study period. This is true for all of the PJM zones that include a portion of Maryland. These price increases are a direct result of the carbon emissions tax imposed on generators.

Prices are projected to rise more quickly over time in the low load growth scenarios because the generation fleet in these scenarios is less efficient than in the other scenarios because the low load growth scenarios have fewer new, efficient natural gas units added during the study period. For example, approximately 30 GW of new natural gas capacity comes on-line over the study period in the LTER Reference Case compared with just over 8 GW in the Low Load scenario. Without new natural gas units coming on-line, older and less efficient units operate at the margin more frequently and thus increase the price of electricity.

Real price increases are lowest in the low natural gas price scenarios. Replacing the LTER Reference Case natural gas prices with the lower natural gas prices (i.e., the LPNG scenario) reduces the 20-year average annual growth rate of PJM-SW real prices by almost 1.3 percentage points from 2.31 percent to 1.03 percent. PJM-MidE and PJM-APS prices respond similarly to the lower natural gas price assumption, with average annual growth rates falling by 1.13 and 1.44 percent, respectively.

13.5.2 On- and Off-Peak Prices

Wholesale energy prices vary depending upon the time of day and prices are typically higher in peak periods, defined by PJM as 6:00 a.m. to 11:00 p.m., Monday through Friday as compared to off-peak periods (weekends, the late night/early morning period, and holidays). Table 13.12 shows how the real average annual on-peak price compares to the off-peak price on a percentage basis. Results for the year 2010 are not included in the table, as the results are virtually identical across scenarios at the beginning of the study period with on-peak prices approximately one-third higher than off-peak prices in all three of the PJM zones that include portions of Maryland and across all scenarios. However, as loads and resources change, so too does the relationship between the on-peak and off-peak prices.

In most of the scenarios, the spread between the on-peak and off-peak prices increases over the first ten years of the study period and then decreases (i.e., on-peak and off-peak prices move closer together) in the second half of the period. This pattern is very similar to the pattern in the all-hours energy prices and is driven by the same factor – the addition of new natural gas-fired capacity.

Table 13.12
On-Peak/Off-Peak Price Variability: Percentage Differential in On-Peak Relative to Off-Peak Periods (%)

Scenario	PJM-SW		PJM-MidE		PJM-APS	
	2020	2030	2020	2030	2020	2030
Reference Case	57.6	36.1	43.5	30.3	53.6	32.0
MSD	54.3	34.9	44.0	30.7	56.0	33.7
MAPP	49.7	33.5	47.4	32.2	52.6	32.2
CC3	58.6	36.3	44.0	30.7	60.9	32.6
MSD+ MAPP	49.7	33.3	47.4	32.4	52.3	34.4
CC3 + NCO2	51.2	27.6	36.1	24.4	51.3	27.5
CC3/NCO2/ MSD /MAPP	44.4	25.9	39.1	25.1	45.5	26.9
NCO2	49.1	27.1	37.1	24.1	49.3	27.3
NCO2 + MSD	48.2	27.1	37.5	24.3	50.5	27.9
High Gas	47.0	25.8	36.6	20.4	45.3	24.6
High Gas + MSD	45.1	24.6	36.7	19.9	46.5	25.0
Low Gas	70.8	55.2	55.3	49.7	67.0	52.8
Low Gas + MSD	72.5	56.5	56.6	52.0	72.5	56.0
High Loads	49.2	34.8	43.3	26.3	46.4	28.8
High Load + MSD	48.6	33.1	44.4	28.0	48.0	31.1
High Load + CC3/ NCO2/MSD/ MAPP	40.9	24.9	40.8	23.7	41.4	25.7
Low Loads	57.9	42.6	34.6	34.2	57.1	41.1
Low Load + MSD	56.1	39.4	34.4	33.6	58.6	40.4
Low Load + NCO2/CC3/MSD/MAPP	41.6	29.9	33.0	29.1	43.4	30.5
High Renewables	60.9	36.1	44.0	28.7	55.2	31.8
High Renew + MSD	57.8	34.8	44.7	30.4	58.7	33.5
High Renew + CC3/NCO2	52.2	26.4	37.1	23.0	52.9	27.0
High Renew + CC3/NCO2/MSD/MAPP	44.2	25.9	38.9	25.3	45.1	26.7
EE	56.0	35.1	43.5	31.1	56.4	32.9
EE + MSD	54.8	34.1	43.5	30.4	57.1	33.6
EE + CC3 + NCO2	55.3	26.6	37.3	24.7	56.4	27.2
EE + NCO2 + CC3 + MAPP + MSD	45.9	26.6	39.8	25.5	47.9	27.0
Climate Change	52.5	34.8	42.7	30.6	51.2	30.2
Climate Change + CC3/NCO2/MSD/ MAPP	42.6	24.8	39.5	24.4	44.5	25.4

In 2010, on-peak prices are approximately one third higher than off-peak prices for all scenarios.
Note: The percentage differential is defined as: [Annual average on-peak price in 2010 $/Annual average off-peak price in 2010 $]-1.

The on-peak/off-peak spread in PJM-SW increases over the 2010-2020 period from 33.5 percent in 2011 to 57.6 percent in 2030.[30] Similarly, the on-peak/off-peak spread increases from 33.5 percent in 2011 to 43.5 percent by 2020 in PJM-MidE. In PJM-APS, the spread increases from 33.2 percent in 2011 to 56.3 percent in 2020. The on-peak/off-peak spread grows over the first half of the study period in all three of the Maryland zones as load growth erodes PJM excess generating capacity. The addition of new natural gas generation decreases prices, particularly in the peak period, which reduces the on-peak/off-peak spread. The scenarios with relatively higher levels of new natural gas capacity tend to have the lower on-peak\off-peak price spreads.

Natural gas prices are also an important factor in determining the relationship between on-peak and off-peak prices. The on-peak/off-peak price spread is greatest in the low natural gas price scenarios. The marginal fuel in PJM is typically natural gas. When natural gas prices are low, natural gas capacity increasingly operates as baseload capacity rather than as mid-merit or peaking capacity which is the case when natural gas prices are high. With more efficient natural gas units, period of high demand are increasingly served by less efficient units characterized by higher running costs.

13.5.3 Seasonal variability

Wholesale electricity prices vary by season and PJM is a summer-peaking region. Given the load shapes employed in this analysis, wholesale energy prices are highest in the summer months, and ten to reach their peak in July. Wholesale prices are lowest in the shoulder periods

[30] 2011 on-peak/off-peak spreads are reported instead of 2010 because a supply constraint in July 2010 produced abnormally high peak period prices that are not representative of the general price patterns of 2010 or subsequent years.

just before and after the summer months. Figure 13.25 shows the average real all-hours energy price by month in the PJM-SW region in the LTER Reference Case for 2010, 2015, 2020, 2025 and 2030. Prices in the PJM-MidE and PJM-APS regions exhibit a similar pattern. The same general pattern is also consistent over all the scenarios.

Figure 13.25 LTER Reference Case Monthly Average All-Hours Energy Price

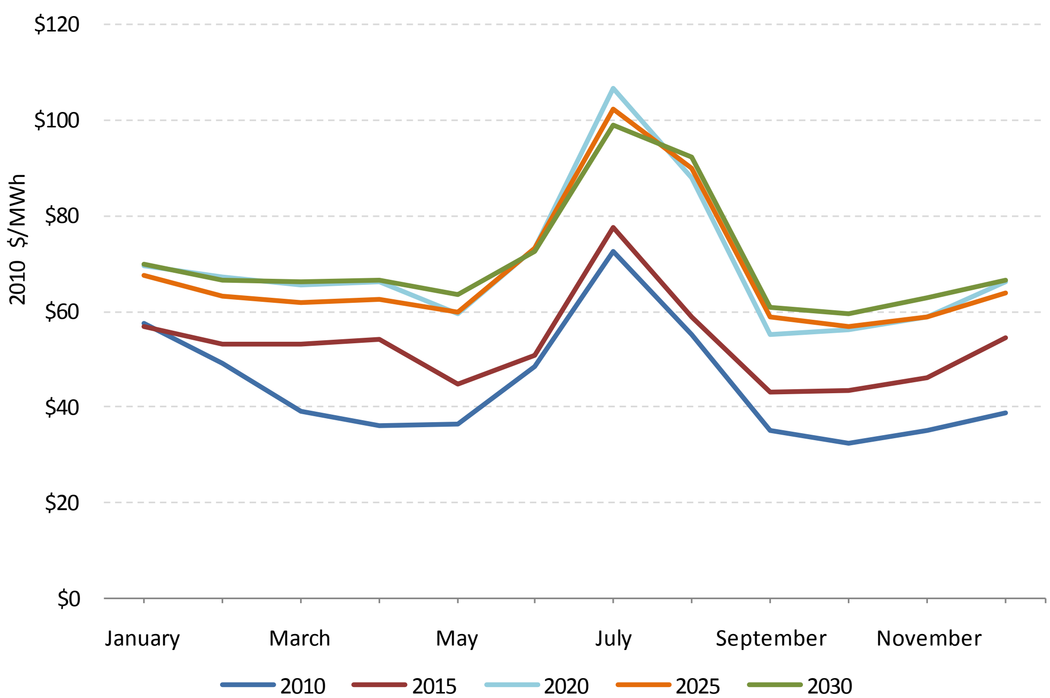


Table 13.13 shows the ratio of the highest and lowest all-hours average monthly price for the years 2020 and 2030 ("Seasonal Ratio"). This Seasonal Ratio is a measure of the variability of monthly all-hours real energy prices within a given year and the ratio increases as the maximum and minimum monthly average prices diverge. The maximum price occurs each year in the summer while the minimum price occurs in the fall.

Table 13.13
Seasonal Price Variability: Ratio of Highest and Lowest Monthly All-Hours Real Price

Scenario	PJM-SW		PJM-MidE		PJM-APS	
	2020	2030	2020	2030	2020	2030
Reference Case	1.94	1.66	1.65	1.60	1.69	1.52
MSD	1.85	1.64	1.66	1.60	1.80	1.58
MAPP	1.73	1.60	1.72	1.61	1.69	1.51
CC3	1.90	1.66	1.71	1.60	1.82	1.54
MAPP+MSD	1.71	1.61	1.71	1.61	1.66	1.57
CC3+NCO2	1.76	1.48	1.63	1.44	1.69	1.46
RC+CC3/NCO2/MSD/MAPP	1.73	1.45	1.69	1.44	1.64	1.47
NCO2	1.77	1.47	1.59	1.45	1.66	1.46
NCO2+MSD	1.75	1.48	1.60	1.45	1.68	1.48
High Gas	1.77	1.47	1.55	1.38	1.61	1.40
High Gas +MSD	1.71	1.45	1.56	1.40	1.69	1.43
Low Gas	2.18	1.93	1.88	1.89	1.90	1.75
Low Gas +MSD	2.25	1.94	1.97	1.93	2.14	1.78
High Load	1.86	1.67	1.72	1.52	1.72	1.47
High Load + MSD	1.82	1.62	1.75	1.55	1.77	1.51
High Load +CC3/NCO2/MSD/MAPP	1.71	1.45	1.72	1.44	1.66	1.43
Low Load	1.87	1.67	1.55	1.50	1.71	1.55
Low Load +MSD	1.85	1.56	1.55	1.48	1.76	1.55
Low Load+CC3/NCO2/MSD/MAPP	1.50	1.46	1.51	1.41	1.53	1.47
HIRNEW	2.00	1.65	1.65	1.55	1.70	1.51
HIRNEW+MSD	1.90	1.63	1.67	1.59	1.84	1.57
HIRNEW+CC3+CO2	1.75	1.46	1.64	1.41	1.70	1.47
HIRNEW+CC3+CO2+MSD+MAPP	1.73	1.44	1.68	1.42	1.64	1.45
EE	1.84	1.63	1.66	1.61	1.74	1.54
EE+MSD	1.80	1.60	1.65	1.59	1.78	1.57
EE+NCO2+CC3	1.79	1.45	1.65	1.42	1.72	1.46
EE+CC3/NCO2/MSD/MAPP	1.71	1.48	1.71	1.46	1.68	1.48
Climate Change	1.94	1.66	1.72	1.63	1.76	1.48
Climate Chg+CC3/NCO2/MSD/MAPP	1.74	1.45	1.73	1.44	1.70	1.46

Seasonal ratios for 2010 are excluded from Table 13.13 because they do not vary across scenarios. The seasonal ratios for PJM-SW and PJM-MidE are equal to 1.41, which means that the average price in the high-priced summer months is 41 percent higher than the average price in the lower-priced shoulder months. The seasonal ratio in PJM-APS at the beginning of the study period is 1.36, which is lower than in PJM-SW and PJM-MidE, due the zone's significant coal capacity combined with the zone's relatively mild summer weather.

The seasonal ratios exhibit a similar pattern to the on-peak/off-peak load variability with increases in the 2010 through 2020 period followed by a decrease over the 2020 through 2030 period, as generating capacity is added. The low natural gas price scenarios have the highest seasonal ratios because, as explained in the last section, the more efficient natural gas plants operate at relatively high capacity factors, with peak demand conditions served by less efficient plants. The rest of the scenarios have seasonal ratios in the 1.4 to 1.6 range, which is relatively close to the levels that characterize the beginning of the study period.

However, seasonal and on-peak/off-peak variability are fundamental characteristics of electric systems given the seasonal and daily variability of load, and neither will be (or should be) completely eliminated. Both types of price variability are important means by which to contain overall costs because they send end-use customers price signals about the marginal value of electricity at different times of the day and different seasons of the year, thereby facilitating the more efficient use of electric power.

13.6 PJM Production Costs and Revenues

13.6.1 Introduction

Total energy production costs are calculated as the sum of fuel costs, fixed and variable O&M costs, and emissions costs. Emissions costs consist of the costs associated with the

Regional Greenhouse Gas Initiative, the Clean Air Act, EPA's Clean Air Transport Rule, and in the LTER scenarios that include national carbon legislation, the costs of carbon allowances. Note that there are certain elements that are not included in the calculation of total production costs (see Table 13.14). Revenues are calculated as the sum of energy revenues and capacity revenues. All energy production costs and revenues are outputs of the Ventyx model.

Table 13.14
Total Production Cost Elements

Included:	**Excluded:**
Fuel Costs	Transmission Charges
Variable O&M	RECs Costs
Fixed O&M	Capital Costs
Emissions Costs	Energy Efficiency Programs

Capital costs for PJM were calculated separately from the total production costs. Capital costs have been estimated for the generic natural gas auto-builds, Calvert Cliffs Unit 3, and all renewable projects built during the study period. The capital costs have been levelized to reflect the capital costs allocatable to the study period.

The Ventyx model produces levelized capital costs for all of the generic natural gas auto-builds created for each scenario. The model does not, however, produce levelized capital costs for any renewable resources or Calvert Cliffs Unit. To more accurately portray the variance of capital costs across scenarios, we have estimated the levelized capital costs associated with Calvert Cliffs 3 and the renewable energy projects brought on-line during the study period. To estimate the levelized capital costs of building Calvert Cliffs 3, we assumed an overnight construction cost of approximately $10 billion, and applied a carrying cost of 11.9 percent.

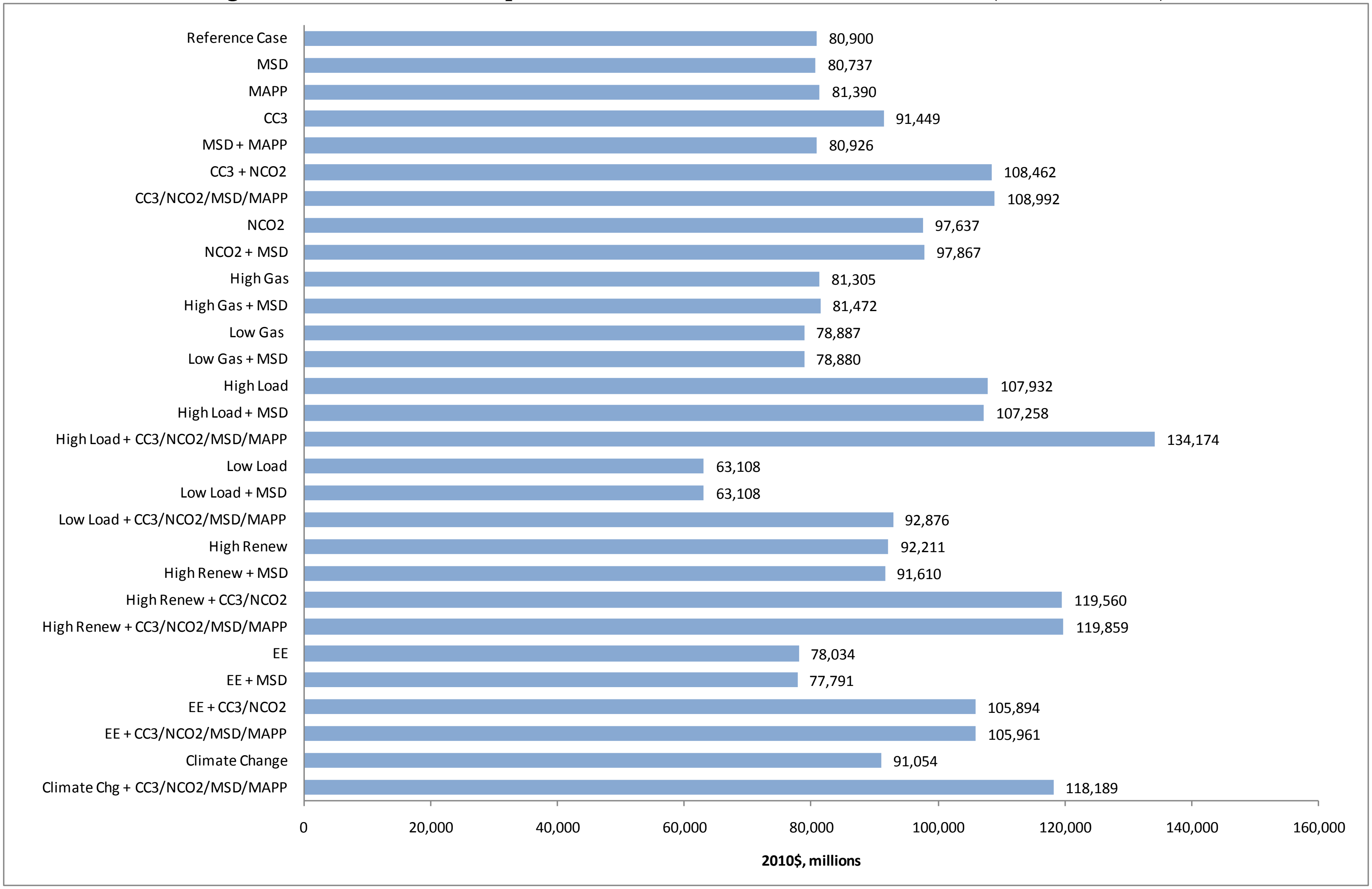
Levelized capital costs for renewables projects were calculated using the assumed overnight construction costs for each resource (see Table 3.10 in Chapter 3), with a carrying cost of 13 percent. Note that the capital costs for existing infrastructure and planned new generation are excluded from the total PJM capital costs calculations because these capital costs are sunk costs and do not vary across scenarios.

The PJM revenue projections presented in this section include both energy and capacity revenues. Excluded from the calculations are revenues associated with the sale of ancillary services, which is relatively minor component.

13.6.2 Cost and Revenue Graphs

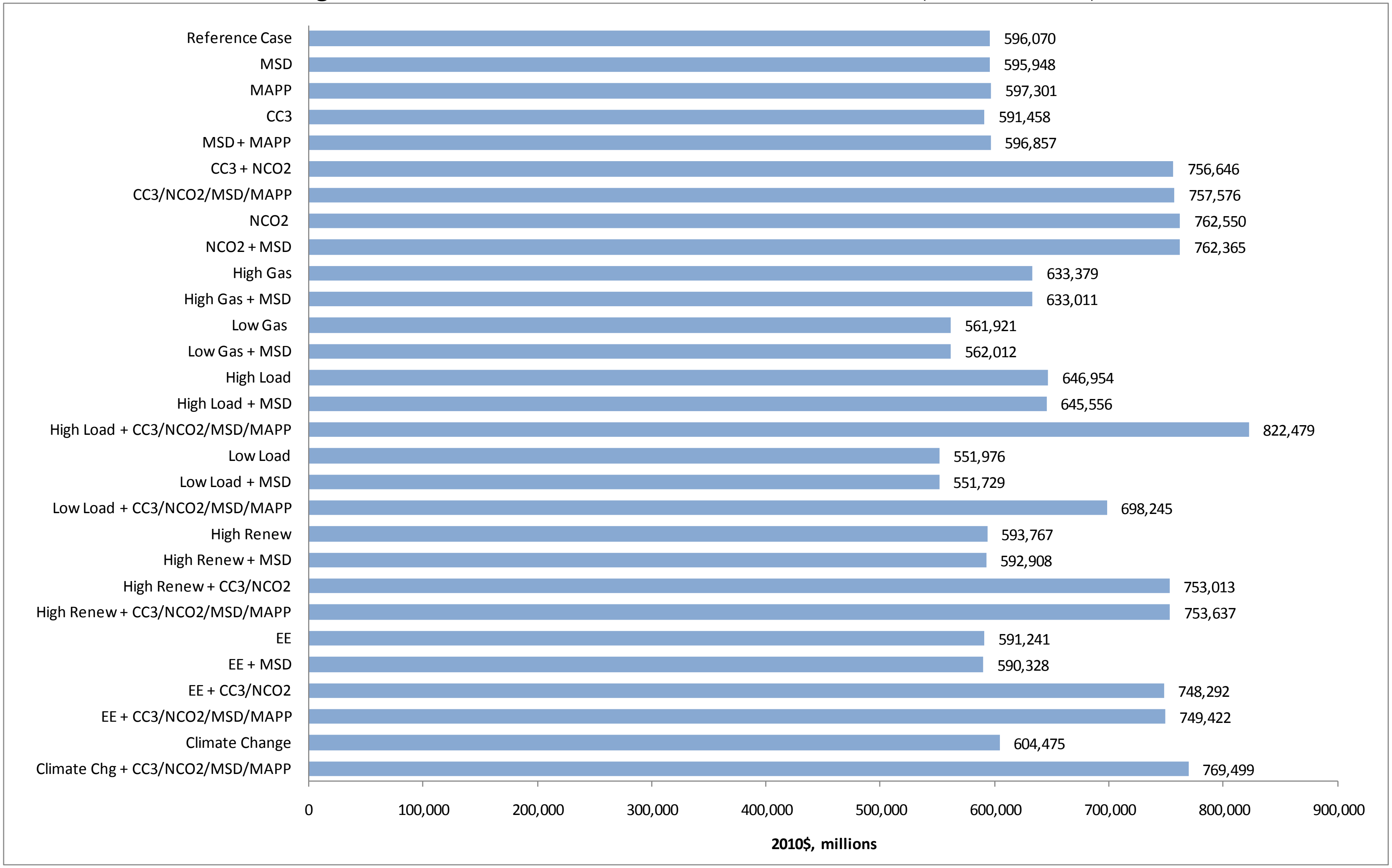
Based on the aforementioned assumptions, capital costs, production costs, and energy revenues were calculated to facilitate comparisons across scenarios. Figure 13.26 displays generic capital costs in PJM during the study period; Figure 13.27 and Figure 13.28 show energy production costs and revenues, respectively; and Figure 13.29 displays the sum of production costs and capital costs accumulated over the full 20-year study period.

Figure 13.26 Total PJM Capital Costs of New Generation*, 2010 – 2030 (2010$, millions)



*Total PJM capital costs are based on the levelized capital costs of new generation (i.e., generic gas builds, renewable energy projects, and Calvert Cliffs 3).

Figure 13.27 Total PJM Production Costs*, 2010 – 2030 (2010$, millions)



*Production costs include variable and fixed O&M costs, fuel costs, and emissions costs.

Figure 13.28 Total PJM Energy Plus Capacity Revenues, 2010 – 2030 (2010$, millions)

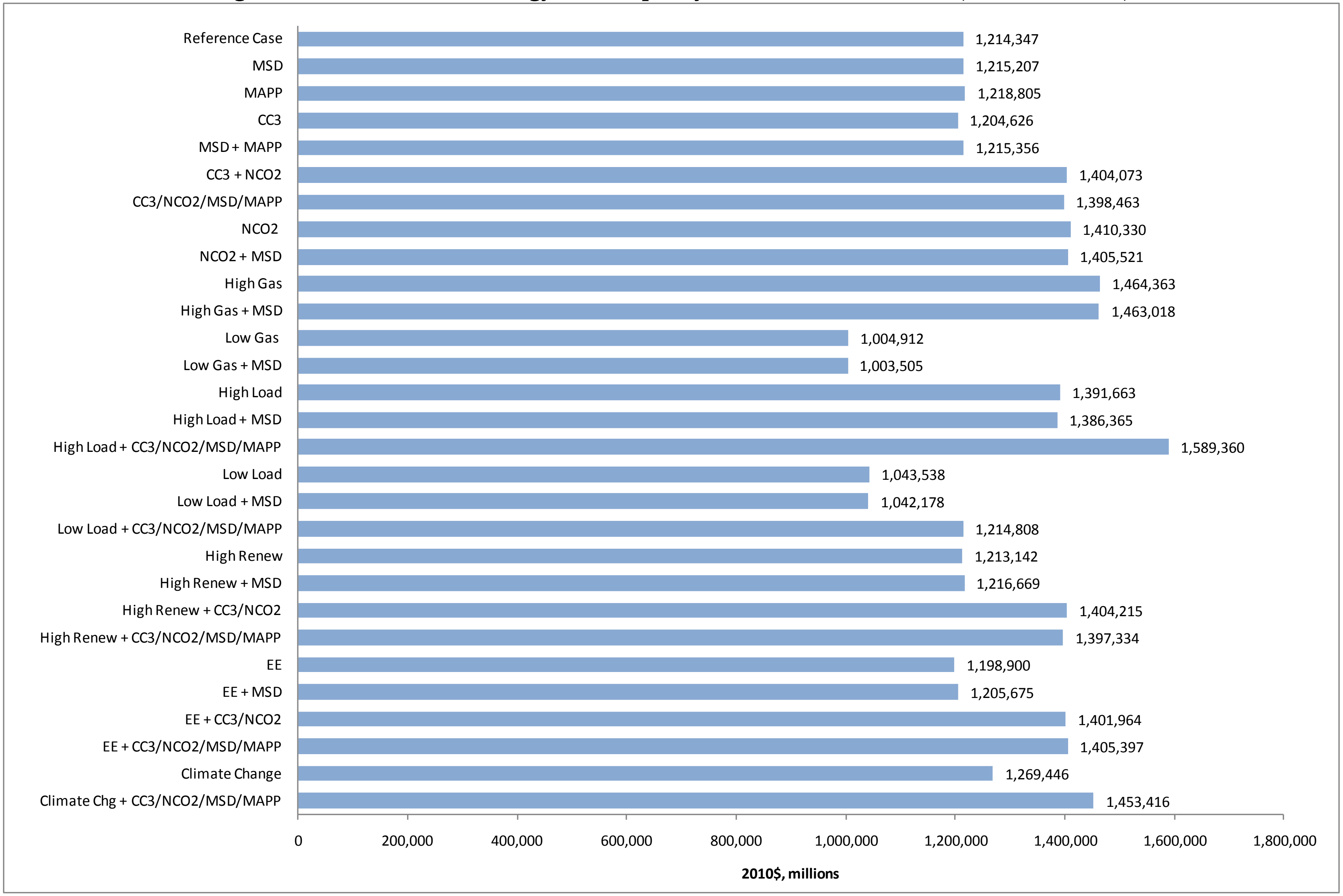
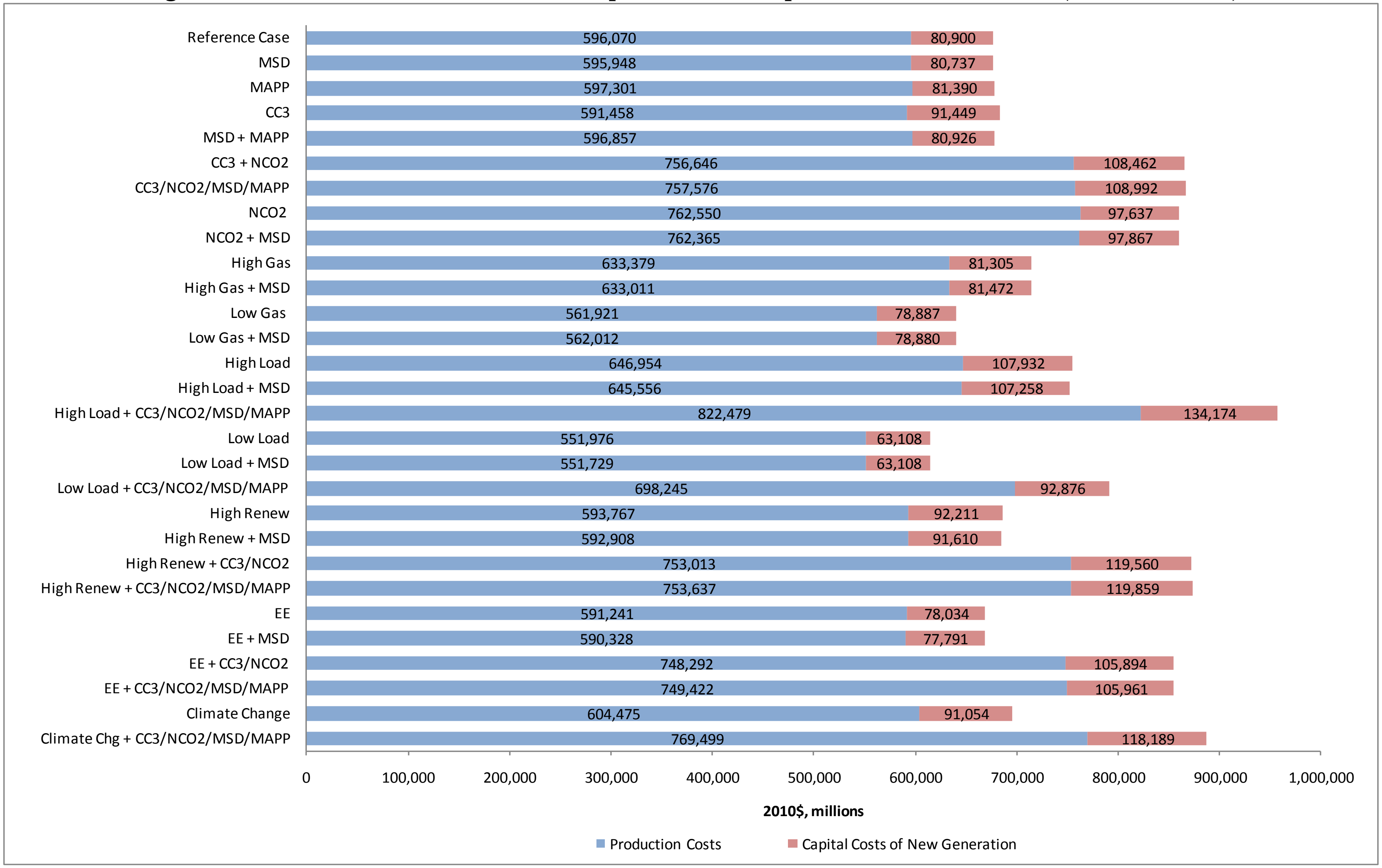


Figure 13.29 Total PJM Production Costs plus Generic Capital Costs*, 2010 – 2030 (2010$, millions)



*Production costs include variable and fixed O&M costs, fuel costs, and emissions costs. Capital costs are based on the levelized capital costs of new generation (i.e., generic gas builds, renewable energy projects, and Calvert Cliffs 3).

13.6.3 Capital Costs in PJM

As explained above, capital costs in PJM represent the costs of generic infrastructure added in each scenario, Calvert Cliffs 3 capital costs, and the capital costs associated with new renewable energy projects. The principal factors affecting the magnitude of capital costs in PJM include load levels, national carbon legislation, high renewables in Maryland, Calvert Cliffs 3, and the assumed change in weather represented in the climate change scenarios.

With higher loads, the need for new generating capacity increases and consequently the level of capital costs increases relative to the LTER Reference Case; the high load cases entail higher capital costs since more generating facilities are needed to accommodate the higher load levels. For lower loads, the need for generating capacity additions decreases relative to the LTER Reference Case, therefore we observe lower total capital costs. The implementation of national carbon legislation, which is tied to the implementation of a national RPS, induces an increase in natural gas and renewable generating capacity additions; capital costs, therefore, are increased relative to the LTER Reference Case. Under the high renewables scenarios, we also observe an increase in capital costs relative to the LTER Reference Case due to the higher capital costs of renewable generating facilities (compared to generic natural gas plants).

As expected, the addition of Calvert Cliffs 3 increases total capital costs because of the significant capital costs associated with this project. In the Climate Change scenarios, higher ambient temperatures result in an increase in peak demand relative to the LTER Reference Case, though almost no change in annual energy consumption. The Climate Change scenario assumptions result in higher levels of peaking capacity than evident for the LTER Reference Case, and a consequential increase in capital costs. In all of the scenarios that include Calvert

Cliffs 3 and national carbon legislation, we observe a cumulative increase in total capital costs of about $27 billion (i.e., these two factors together add roughly $27 billion to the level of capital costs in any scenario that includes this combination). The high load scenario that includes both the construction of Calvert Cliffs 3 and the implementation of national carbon legislation results in the largest increase in capital costs relative to the LTER Reference Case.

13.6.4 Total Production Costs in PJM

Production costs include fuel costs, fixed and variable O&M costs, and emissions costs. The enactment of national carbon legislation is the most significant factor affecting total production costs relative to the LTER Reference Case. In each scenario that includes the implementation of national carbon legislation, total production costs increase by approximately $166 billion relative to the LTER Reference Case, due to the cost of carbon allowances in the PJM region.

High natural gas prices serve to increase total production costs relative to the LTER Reference Case. With lower natural gas prices, the level of production costs is lower than under the LTER Reference Case assumptions. Note that in the High Renewables scenario, there is a slight decrease in production costs relative to the LTER Reference Case resulting from reduced fuel usage, and hence reduced fuel costs.

Energy consumptions levels in PJM are also a factor determining production costs because energy consumption affects fuel consumption, variable O&M costs, and emissions costs. Therefore, with higher levels of energy consumption (including the High Load and Climate Change scenarios), production costs are increased relative to the LTER Reference Case. For lower levels of energy consumption (including the Aggressive Energy Efficiency scenarios), production costs are lower than in the LTER Reference Case. The largest production cost increases relative to the LTER Reference Case are associated with the combination of higher energy consumption levels and national carbon legislation.

13.6.5 Energy and Capacity Revenues in PJM

The above graphs indicate that total revenues in PJM (energy plus capacity revenues) are higher than total costs in PJM (even when capital costs are included). There are several reasons for this difference. First, capital costs for all existing and planned generating facilities are excluded from this analysis. In addition to the omitted capital costs, the difference is further affected because energy revenues and capacity payments are based on market prices, which are set by the marginal (most costly) units but are paid to all generators, not just the marginal generating facilities. For example, energy revenues in any given hour may be based on the costs of a natural gas facility, but renewable energy generators with much lower production costs receive the same per-MWh revenue.

In general, the changes in revenues relative to the LTER Reference Case mirror the changes in production costs. However, in the case of high and low natural gas prices, the variance in revenues from the LTER Reference Case is magnified in comparison to production costs, because changes in natural gas prices cause substantial changes in energy prices. The energy revenues for electricity generators that do not use natural gas as a fuel source, therefore, will increase or decrease based on the change in overall energy prices. These generators include nuclear facilities, coal-fired facilities, and renewable energy generators.

13.7 Additional Costs

Certain additional costs may affect the price of electricity to end-use customers. These costs are not quantified in this analysis owing principally to high degrees of uncertainty surrounding either the potential magnitude of the costs or the method by which those costs would be collected. Additional costs not fully accounted for in the modeling approach that are likely to affect end-users include:

- Costs related to new transmission lines;
- Costs associated with uneconomic generation additions;
- Costs related to energy efficiency and conservation programs; and
- Costs resulting from increased renewable energy requirements.

Each is discussed in turn, below.

13.7.1 New Transmission Line Costs

The cost of transmission system expansion is not accounted for in the model results and needs to be recognized as a potential cost element facing end-use customers of electricity in Maryland. The alternative scenarios include two potential expansions of the PJM transmission system: the upgrade of the Mt. Storm to Doubs transmission line and the construction of the Mid-Atlantic Power Pathway. Because these are high-voltage transmission projects, the recovery of project costs (including the authorized rate of return on invested capital), the project costs eligible for recovery, the rates that would allow recovery of costs, and the ratepayers responsible for cost recovery are set by the Federal Energy Regulatory Commission ("FERC"). If it is determined by FERC that the costs associated with a specific transmission line will be socialized, that is, recovered from all PJM customers, the costs of that line that would be borne by any individual end-use customer would be significantly less than if the costs were allocated only to a subset of PJM customers. Under the socialized cost recovery approach, the costs are spread over a larger number of customers and the cost to any specific customer is consequently less than if cost recovery were determined to be the responsibility of a subset of customers.

Over the 20-year analysis period, high-voltage transmission lines other than MAPP and Mt. Storm to Doubs may be needed to ensure the reliability of the transmission system. The costs associated with these potential and unspecified transmission projects would also entail added costs to end-use customers.

13.7.2 Uneconomic Generation Additions

In a restructured electric utility industry market, generation owners are not subject to rate-of-return regulation. While any new generation project is still subject to regulations governing emissions, other environmental factors such as water use and land use, and safety, the developers of the project bear the risk that the project may be unprofitable. If the project proves to be uneconomic and is unable to generate revenues adequate to cover costs, that burden would fall on the owners of the project rather than on the general body of ratepayers. However, if a project is constructed under the terms of a long-term power purchase agreement ("PPA") that would specify, among other things, the price of the power to be purchased and the duration of the contract, the counterparty to the contract (for example, the State or one or more utilities) would then bear the risk of the project being uneconomic relative to market prices for the duration of the contract term.[31] The generator, however, would continue to bear the risks related to plant performance and elements of cost risk (e.g., construction costs).

In terms of the alternative scenarios considered in the LTER, one of the variations addressed is the construction of Calvert Cliffs Nuclear Unit 3. If the project is developed independent of any State or utility contracts for the purchase of some or all of the power that would be generated from Calvert Cliffs 3, to the extent that the project were to prove to be uneconomic, end-use customers in Maryland would be unaffected economically with respect to power supply costs. If the project were to be developed under a State contract for the purchase of the power, or under a State-directed contract (or contracts) entered into by the utilities, and the project proved to be uneconomic, end-use customers would bear an added cost over and above the costs implied by the LTER market price results. The outcome, however, is not limited to the development of Calvert Cliffs 3, but rather applies to any uneconomic contract that would be entered into by the State or directed to be entered into by the State.

To the extent, however, that the projects at issue ultimately emerge as economic based on any of a variety of factors (e.g., natural gas prices rise much more quickly than anticipated or new federal regulations governing emissions of CO_2 are much more costly than expected), a project such as Calvert Cliffs 3 may prove to be highly economic. Where the State has either entered into a PPA or has directed the utilities to enter into a PPA, Maryland's end-use customers would economically benefit from bearing risk that ultimately emerges as entailing a favorable economic outcome.

[31] It should be noted that a PPA can contain clauses that effectively cause the price risk to be shared by the buyer and the seller.

Additional benefits that may accrue to end-use customers (and Maryland residents at large) and that are not fully captured in a narrow evaluation of economic costs include benefits related to: (1) system reliability, (2) emissions reductions, (3) increased diversity of fuel, (4) economic development, (5) price stability, and (6) other benefits determined by policy-makers to outweigh the expected additional economic costs. The narrow economic assessment based purely on projected prices may not support the same decision as would be made with reliance on a broader set of recognized benefits.

13.7.3 Energy Efficiency and Conservation Programs

Some of the alternative scenarios considered in the LTER include the assumption of a set of more aggressive energy efficiency and conservation programs being put in place in Maryland. The costs of these programs, to the extent that they are funded through a surcharge on electric power supply or services, would result in an additional cost element not accounted for in the LTER analysis. The LTER analysis does capture the impacts of the implementation of such a program (reduced energy consumption and emissions, power supply price impacts, total cost of power supply production), but does not capture the costs of program implementation.

13.7.4 Increased Renewable Energy Requirements

One of the variations to the LTER Reference Case entails an increase in the requirements under Maryland's Renewable Energy Portfolio Standard ("RPS"). Currently, Maryland's RPS calls for qualifying renewable energy to account for 20 percent of Maryland's total energy consumption by 2022, with at least two percent of the 20 percent required to come from qualifying solar energy projects. Under the High Renewables scenarios, the Maryland RPS is assumed to increase from 20 percent in 2022 to 30 percent by 2030. Of the 30 percent renewables requirement, the solar power requirement of two percent is unchanged.

An increase in the Maryland RPS requirement will likely entail increased costs to Maryland end-use customers through the required purchase of additional Renewable Energy Certificates ("RECs") needed to meet the higher RPS requirements. RECs costs are not accounted for in the calculations of total revenues to generators.

Estimating the value of RECs under the LTER Reference Case or any of the alternative scenarios is highly complicated given the complexity of the renewable energy markets. Most of the states within PJM have enacted mandatory RPS legislation,[32] and there are marked differences among the percentages of renewable energy required, the types of energy that are considered as eligible for a given state's RPS requirement, and the geographical area from which renewable energy may be generated to meet a state's RPS requirement. An additional complicating factor is that satisfaction of a state's RPS may be accomplished either through the purchase of qualifying RECs or through the payment of an Alternative Compliance Payment ("ACP"). The ACPs differ among the states and also differ for different types of renewables, for example, the ACPs for solar RPS compliance are much higher than the ACPs for Tier 1 renewable energy.

The ACPs effectively function as a cap on the price of RECs. If a retail energy supplier can meet the RPS requirement through payment of an ACP for $20, the supplier would not be willing to purchase RECs for $25. Consequently, the ACP represents the maximum amount that

[32] Indiana, Kentucky, Tennessee, Virginia, and West Virginia have not enacted mandatory RPS legislation.

a RECs supplier could expect to sell RECs for on the market. Since there are transactions costs associated with the purchase of RECs, a retail energy supplier, in fact, would only be willing to pay a price slightly below the ACP for REC. Because RECs can be banked only for three years by the RECs generator, the generator has an incentive to sell the RECs below the price of the ACP to avoid the potential of the RECs becoming worthless. An additional complexity is that since RECs generated in one PJM state are typically eligible to satisfy the RPS from another PJM state, the market for RECs in one state is affected by the ACPs in other states.

Finally, it should be recognized that not all RECs are used to satisfy RPS requirements. A firm may purchase RECs over and above the level required for satisfaction of the relevant state RPS for marketing purposes or to comply with company policy. Additionally, residential consumers can opt to purchase renewable energy in excess of RPS requirements for reasons of personal preference and government entities may also purchase excess renewable energy to satisfy policy directives. For example, each of the service branches of the U.S. Department of Defense purchase renewable energy in excess of state RPS requirements to comply with a federal Executive Order.

The degree to which additional costs to comply with higher RPS requirements are borne by consumers depends upon two factors: the price of RECs and the size of the RPS requirement, usually expressed as a percentage of energy consumption. In Maryland, as in other PJM states, the size of the existing RPS requirement is established by legislation. Under the High Renewables scenarios, we assumed that the percentage requirement for Maryland would increase to 30 percent by 2030. As a consequence, the size of the RPS requirement is either known or assumed. Attaching a RECs price to the RPS requirement, however, is more complex. The derivation of the RECs prices used in the LTER, and the implications for costs to end-use customers, is addressed in Section 13.8, which follows below.

13.8 Renewable Energy Certificate Costs

As addressed in Section 13.7.4, market factors affect the price of RECs in Maryland (as well as in other states) in complex ways. Consequently, any approach to modeling RECs prices is likely to provide results that entail a high degree of uncertainty. The RECs prices presented below were modeled using a "gap analysis" approach based on relevant outputs from the Ventyx model. The gap analysis estimates the gap in revenue required to fully compensate renewable energy developers for the cost and expense of constructing, owning, and operating a renewable energy facility given the revenue stream obtained from the sale of energy and capacity from the renewable energy project, that is, the RECs price is equal to costs (including return) minus revenues from energy and capacity sales. In addition to the revenue associated with energy and capacity sales, the reduction in project costs due to the federal Production Tax Credit ("PTC") is assumed to also be available to the project developer.

RECs prices will vary from scenario to scenario due to differences in the energy prices and the capacity prices. Renewable energy project costs (both fixed and variable) are assumed to be invariant among scenarios. Table 13.15, below, shows the annual RECs prices derived from the gap analysis for a set of representative scenarios.

Table 13.15
Estimated Maryland REC Prices ($2010 per MWh)

Year	Reference Case	High Renewables with CC3, National CO_2 Legislation, MAPP, and Mt. Storm to Doubs	High Renewables Scenario	National CO_2 Legislation Scenario	High Natural Gas Price Scenario	Low Natural Gas Price Scenario
2010	2	2	2	2	2	2
2011	2	2	2	2	2	2
2012	3	3	3	3	3	3
2013	16	16	16	16	12	18
2014	28	28	28	28	22	33
2015	26	16	26	16	20	31
2016	25	15	25	15	19	31
2017	24	15	24	15	17	30
2018	24	13	24	13	16	30
2019	24	14	25	14	24	30
2020	25	9	25	9	10	30
2021	24	7	24	7	14	29
2022	25	6	24	6	9	28
2023	24	4	23	5	13	27
2024	22	5	21	5	16	27
2025	18	0	17	0	7	26
2026	17	0	16	0	3	25
2027	16	0	15	0	4	25
2028	14	0	14	0	0	24
2029	13	0	13	0	0	23
2030	12	0	12	0	0	23

In the LTER Reference Case, during the early years of the analysis period RECs prices are relatively low, reflecting the current surplus of RECs compared to RPS requirements. As the surplus diminishes with the growth in load and increases in the RPS renewables percentage requirements, the renewable energy surplus is reduced and increasing tightness in the renewable energy market increases, resulting in increases in RECs prices. Between 2015 and 2023, RECs prices are stable (between $24 and $26), as increases in RECs requirements are balanced with increases in renewable energy project development. With increases in capacity prices and (to a lesser extent) in energy prices, and with no increases in the percentage requirements for renewable energy (which reach a maximum of 20 percent in 2022 in Maryland), RECs prices decline in real terms over the last seven years of the analysis period under the LTER Reference Case assumptions, falling to $12 per REC by 2030.

The REC prices under the High Renewables Scenario assumptions are very similar to those estimated for the LTER Reference Case. While under the High Renewables Scenario the demand for RECs is greater (the Maryland RPS is increased from 20 percent in 2022 to 30 percent by 2030), more renewable energy projects are developed under this scenario (relative to the LTER Reference Case) to meet the higher renewable energy demand levels. As a consequence, the price impacts associated with the increase in demand are counter-balanced with the price impacts associated with the increase in supply, resulting in similar RECs prices in the two scenarios (the LTER Reference Case and the High Renewables Scenario).

Where the High Renewables Scenario assumptions are combined with the assumed construction of the Calvert Cliffs Unit 3 nuclear facility, the construction of the MAPP transmission line, the upgrade of the Mt. Storm to Doubs transmission line, and the enactment of national CO_2 legislation, the estimated RECs prices are substantially lower than under the LTER Reference Case and the High Renewables Scenario assumptions. The reason for this is that the implementation of national CO_2 legislation results in increases in the market prices for energy, which reduces the size of the revenue gap that determines the REC prices. With higher market energy prices, renewable energy project developers are able to recover a greater proportion of their costs through the sale of energy and consequently do not require RECs prices as high as those in the LTER Reference Case or the High Renewables Scenario to fully cover their costs. For the same reason, RECs prices under the High Natural Gas Price Scenario are below the

RECs prices in the LTER Reference Case and the High Renewables Scenario. High natural gas prices result in higher energy prices, which in turn put downward pressure on RECs prices.

Under the Low Natural Gas Price Scenario, RECs prices do not fall below $23 per REC after 2014 and throughout the analysis period are generally $25 or higher. Under the Low Natural Gas Price Scenario assumptions, the market prices for energy are below those for the LTER Reference Case and the High Renewables Scenario. With lower market prices for energy, a higher portion of the costs of renewable energy project development need to be recovered through the RECs price using the gap analysis methodology. Under the Low Natural Gas Price Scenario, nominal RECs prices estimated using the gap analysis are above $40 per REC in 2019 through the end of the study period. The nominal estimates above $38 per REC were reduced to $38 per REC in nominal terms to reflect the influence of the ACP, which is $40 per REC (nominal) in those years. The $2 differential represents estimated transaction costs. That is, we assume that the purchaser of RECs would be indifferent to purchasing RECs for $38 per REC and paying an ACP of $40 and avoiding the transactions cost associated with the REC purchase. The nominal REC prices were then converted to the real prices (2010 dollars) shown in Table 13.15. In none of the other scenarios, including the LTER Reference Case, did the REC prices increase to a level of $38 or more in nominal terms. This means that for all scenarios with the exception of the Low Natural Gas Price Scenario, the Alternative Compliance Payment is a non-binding constraint on RECs prices in Maryland.

As noted previously in this section, there is significant uncertainty associated with the estimated RECs prices shown in Table 13.15. This uncertainty results from the complex market interactions that determine the market price for RECs. Adding to the inherent uncertainty resulting from market complexities is the potential that the existing RPS legislation in Maryland or other PJM states could be modified over the course of the analysis period which could affect the market prices for RECs in Maryland. Modifications to RPS legislation that could affect RECs prices include: (1) expanding or contracting the menu of resources that qualify as renewable, (2) expanding or contracting the geographical areas from which qualifying renewable generators may be located, (3) increasing or decreasing the level of Alternative Compliance Payments, (4) increasing or decreasing the renewable energy percentage requirements, and (5) establishing carve-outs from the existing RPS percentages for specific renewable technologies, for example, solar energy or energy from off-shore wind. Since its initial implementation, the Maryland RPS legislation has been modified in all of the above respects and the kinds of modifications enumerated above are not uncommon for the RPSs in other states.

An added source of uncertainty stems from the potential that the federal Production Tax Credit will not be extended. The PTC provides a tax credit equal to 2.2 cents per kWh produced for certain renewable energy technologies (wind power, closed loop biomass) for the first ten years that the project is on line. For other technologies (landfill gas, municipal solid waste, qualified hydro-electric, hydrokinetic), the PTC is limit to 1.1 cents per kWh. The current federal PTC for wind power projects expires at the end of calendar year 2012 and expires for other technologies at the end of calendar year 2013. For purposes of estimating RECs values, we have assumed the continued availability of the PTC, but whether the PTC will be extended beyond its current expiration dates is unclear. If the PTC is not extended, REC prices would increase by approximately the amount of the tax cost reduction foregone.

In Table 13.15, under the two scenarios that include national carbon legislation and in the High Natural Gas Price Scenario, the price of RECs drops to zero in the last years of the analysis period. This means that certain new renewable energy projects, for example, wind power projects, would be capable of covering their full costs through energy and capacity revenues (plus the Production Tax Credit) and therefore would be competitive with conventional (natural gas) technologies. While the Ventyx model does not allow intermittent technologies, that is, technologies that are not dispatchable, to be built by the model to satisfy reliability requirements, towards the end years of the analysis period we may see more renewable energy projects being built than represented by the model if conditions emerge that would make those technologies more competitive with natural gas generation. Specifically, high natural gas prices or national carbon legislation that would result in increased costs to fossil fuel generation without a corresponding increase in costs for renewables power generators.

13.9 Energy Storage

Energy storage technologies and facilities have the potential to provide important and valuable services to the elective grid to enhance system reliability and stability. Energy storage devices currently in use include pumped hydroelectric power, flywheels, batteries, and compressed air facilities.

Pumped hydro, which generates electricity by reversing water flow between reservoirs, is the most widespread energy storage system in use today. With an efficiency rate of more than 80 percent, pumped storage currently provides over 22 GW of electricity storage in the United States. Pumped hydro storage is ideal for peak load shifting. Water is pumped into an upper reservoir when during off-peak periods when market energy prices are low, then uses the stored water to generate electricity during peak hours. As of August 2010, there was almost 5,500 MW of pumped hydro storage capacity in PJM.

Compressed air energy storage ("CAES") makes use of natural and manmade caverns (abandoned gas and oil wells) to store compressed air and recover it for use in a turbine. Excess and inexpensive electricity is used to compress and pump high pressure air into an underground cavern. When electricity is needed and when energy prices are high, the air is released from the cavern, mixed with natural gas, and combusted leading to the air's expansion prior to running it through a turbine to generate electricity. No compressed air storage projects are currently operating in PJM, but one is being considered in Ohio, utilizing a 388-million-cubic-foot former limestone mine near Akron, Ohio.

Battery storage systems are being evaluated for their ability to control and dispatch electricity as needed to meet demand, or for system stability. Lithium ion batteries and sodium sulfur batteries are already being used to provide 15 to 60 minutes of energy storage as regulation services. A few of energy companies are beginning to test the use of batteries for grid management and energy storage. A 1.2 MW battery system was installed in West Virginia in 2006 to test the technology and to help fill capacity gaps and flatten the load in the region. A flow battery uses liquid chemicals to store energy. Total energy storage is limited only by the size of tank used to hold the liquid. A one-MW advanced lithium-ion experimental battery array is housed in a trailer at PJM headquarters providing regulation energy to the grid. The unit can provide one-MW for up to 15 minutes and is also giving PJM an opportunity to test control interfaces for storage operations.

Flywheel systems utilize a massive rotating cylinder, and are a good fit for providing regulation services. Flywheels are commercially available for development as "regulation power plants" providing up to 20 MW of regulation for a 40 MW swing. A flywheel storage regulation power plant is capable of providing full power within four seconds of receiving an ISO control signal. The flywheels have the ability to address both generation and load, acting in a load capacity by recharging using grid energy, and as a generator by releasing energy back. Flywheel energy storage systems also have a quicker reaction time than other regulation resources, meaning just one MW of this type of project may be able to displace between 2 to 17 MW of traditional regulation resources. There are 20-MW flywheel installations operating in the ISO New England and New York ISO grids. A similar facility is being planned in PJM.

Overall, storage can be used as a system resource, i.e., to help meet load requirements or to provide ancillary services. Storage systems with very fast response times are ideal for providing grid regulation services, which require minute-to-minute adjustments in demand and supply to keep these in balance on the electric grid. FERC Order 890 allows for non-generation resources to participate in ancillary services markets. Several RTOs, including PJM, the New York ISO, ISO New England, and the Midwest ISO have adapted their regulation policies to ensure fast-responding storage systems are able to participate in the ancillary services markets and are compensated adequately for those services.

Electricity storage will be increasingly utilized as technologies advance and will likely play a large role in future electric system operations. PJM is actively examining storage technologies and preparing to integrate them into the PJM grid and markets. Figure 13.30 outlines the status of energy storage in PJM, both existing and planned.

Figure 13.30 Energy Storage in PJM

ES Tech	Resource Type	Facility Size Range	PJM Installed or in planning Queue	Typical Discharging Time	Potential Grid Application(s)
Pumped Storage	**Limited Energy**	up to 3100 MW	Muddy Run, Seneca, Yards Creek, Bath County, Smith Mountain	7-13+ hours	Capacity, Energy, A/S
Compressed Air Energy Storage (CAES)	**Limited Energy**	25 MW to 350 MW	N/A	2-14 hours	Capacity, Energy, A/S
Flow Battery, Lead-Acid, Soldium-Sulfur (NaS) Battery	**Limited Energy**	4 to 20 MW	20 MW Battery(Queue V3-057, Ironwood)	1-6 hours	Capacity, Energy, A/S
Flywheel, Li-Battery	**Limited Energy**	0.5 to 20 MW	1 MW Li-Battery(in service); 2 MW Battery(Queue V4-071); 20 MW Beacon flywheel(Queue W1-109); 20 MW Beacon flywheel(Queue, W1-111)	< 2 hours	Energy, A/S
Superconducting Magnetic Energy Storage (SMES), SuperCapacitor, Vehicle-to-Grid (V2G)	**Limited Energy**	100 W to 100 MW	N/A	<= 15 min	A/S

Source: PJM: http://www.pjm.com/~/media/committees-groups/committees/mrc/20100805/20100805-item-10b-limited-energy-resources.ashx

As shown in Figure 13.30, there is very little storage in PJM currently operating (other than pumped hydro), and only about 60 MW presently planned in the region. As such, future storage development and costs are too speculative to effectively model. The implications of technological advances, reduced costs, and more widespread application of storage will be addressed in future LTERs as information becomes less speculative.

13.10 Land Use Requirements for Electricity Generation

The amount of land required to generate electricity varies significantly depending upon the specific attributes of each generating facility, such as the type of resource used for energy production, the capacity of the power plant, and the features of the development site. This section is included in the LTER to identify the average amount of land required per MW of capacity for wind, solar, nuclear, and natural gas resources. Note that this section only addresses the amount of land directly utilized by a power plant, and is not an analysis of the "cradle-to-grave" footprint (i.e., factors such as natural gas wells, pumping stations, pipelines, uranium mines, and waste by-product disposal are not included). Table 13.16 displays estimated land required to accommodate electricity generation for four generation types.

Table 13.16
Land Use Requirements by Energy Source

Resource	Land Area Used for Electricity Generation (acres per MW)	
	Estimated Range	Mean
Wind	30 – 138	84
Solar	2.5 – 12.4	7.45
Nuclear	0.25 – 1	0.625
Natural Gas	0.4 – 2	1.2

These estimates are derived from a review of the existing literature and are not specific to Maryland. As seen in Table 13.16, nuclear and natural gas power plants typically require significantly less land area than wind and solar generating facilities. Also note that the estimated ranges for land requirements for both wind and solar are wide. In the case of wind, the high end of the estimated range (138 acres per MW of wind capacity) differs from the low end of the range by more than 100 acres per MW. For solar, the 2.5 to 12.4 acre-per-MW range is also large.

The wind estimates are based on survey information from approximately 172 projects. The wide range reflects differences in size of the turbines used, the nature of the terrain, and differences in the intensity of land use for other purposes. For example, in areas where grazing or agricultural activities take place within the designated acreage of the wind farm, reported land use figures can be expected to be higher. For projects where the land is exclusively used for wind power generation, and where land values may be higher, more compressed projects would be developed and land requirements on a per-MW basis would be less.

Similarly, different types of solar technology have different levels of efficiency for the conversion of sunlight into electricity. The availability of low-cost land would allow for less efficient (and less costly) technologies to be relied upon. More costly land would dictate reliance on more efficient (and more expensive) technologies to be used. Differences in the selection of technology types and topographical considerations account for the wide disparity in land use requirements reported for solar power generation.

Wind

Onshore wind energy power plants span across hundreds and often thousands of acres, but the turbines used for collecting wind energy typically only utilize about 2 to 5 percent of the total land area.[33] Because the wind resource potential and turbine capacities vary among existing wind energy facilities, it is difficult to estimate a generic acre-per-MW figure. Nonetheless, according to an estimate from the National Renewable Energy Laboratory ("NREL"), the average wind facility occupies 84 (±54) total acres per MW. In terms of the direct impact area (the area where turbine pads, roads, and stations are located), the average wind facility only uses about 2.5 (±1.75) acres per MW.[34]

Although an offshore wind facility does not require any land area for energy production, it is important to note that such a project would still have impacts on the State. The decision to site an offshore wind facility in Maryland waters (i.e., within 3 miles of the coastline), would require careful consideration of potential impacts to shipping lanes, sensitive ocean habitats, avian life, and tourism in beach communities in Maryland.[35] Furthermore, if a project is developed in federal waters (i.e., greater than 3 miles from Maryland's coast), the State could observe similar impacts. Nonetheless, Maryland has limited land area for on-shore wind generation and the State's greatest wind energy potential is located off-shore, presenting certain important advantages to utilizing off-shore wind energy as opposed to on-shore wind energy for renewable energy production.

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[33] National Renewable Energy Laboratory, as sited in David Pimentel et al, Bioscience, Volume 44, #8, Sept. 1994. http://www.nrel.gov/pv/thin_film/docs/035097_pvfaq_land_use.pdf

[34] Paul Denholm et al, *Land Use Requirements of Modern Wind Power Plants in the United States*, National Renewable Energy Laboratory, August 2009.

[35] U.S. Department of Energy, National Renewable Energy Laboratory, *Large-Scale Offshore Wind Power in the United States*, September 2010. http://www.nrel.gov/wind/pdfs/40745.pdf

Solar

According to the Bureau of Land Management ("BLM"), a utility-scale solar facility can generate up to 250 MW of electricity on about 1,250 acres of land, or roughly 2 square miles.[36] As with wind, it is difficult to estimate a generic acre-per-MW figure for solar energy because of the differences among projects; however, based on an estimate from NREL, solar energy typically requires about 2.5 to 12.4 acres per MW.[37] Solar photovoltaic typically requires more land than solar thermal, but both types of solar generation fall within this range.

The land use requirements for solar power projects provided immediately above are for utility-scale projects. Smaller solar projects, those up to several hundred kW, can often be located on rooftops. Placement of solar panels on rooftops is common for residential installations and commercial and government buildings have also used roof space to facilitate installation of solar panels. For these types of projects, land use requirements are minimal since the panels are placed on pre-existing structures.

Nuclear

The land use requirements for a nuclear generating facility are less than the requirements for wind and solar on a per-MW basis. According to an estimate from the American Nuclear Society ("ANS"), a nuclear generating facility typically requires about 0.25 to 1 acre per MW of

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[36] Bureau of Land Management, *Renewable Energy and the BLM: SOLAR*. http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/energy/solar_and_wind.Par.99327.File.dat/10factsheet_Solar_072210.pdf
[37] National Renewable Energy Laboratory, as sited in Gilbert Cohen, Solargenix Energy, Solar Energy Technologies Systems Symposium CD, Albuquerque, 2003.

capacity.[38] The Calvert Cliffs nuclear generating plant in Maryland and the Peach Bottom nuclear generating facility, located in Pennsylvania near the Maryland border each utilize less than one acre of land per MW of generating capacity.

Natural Gas

Natural gas power plants also require less land area per MW than wind and solar facilities. According to a report prepared by the Carnegie Mellon Electricity Industry Center, natural gas turbines require about 0.4 acres per MW of capacity.[39] Another study estimated the land use requirements for natural gas to be as high as 2 acres per MW.[40]

Summary

The approximate amount of land area needed to build new capacity in Maryland based on the means in Table 13.19, are shown in Figure 13.31. The High Renewables scenarios require the most land area, because renewable energy facilities require more land per MW of capacity and more renewable generating capacity is constructed under these scenarios.[41] For each scenario that includes the assumptions that Calvert Cliffs 3 will be constructed during the study period, the new nuclear unit is estimated to add about 400 acres to the total land area used for electricity generation in Maryland through 2030. The 400 acre figure is based on Constellation's

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[38] American Nuclear Society, *Nuclear Power: A Sustainable Source of Energy*. http://www2.ans.org/pi/brochures/pdfs/power.pdf

[39] Jay Apt et al, *Generating Electricity from Renewables: Crafting Policies that Achieve Society's Goals*, Carnegie Mellon University, May 26, 2008. https://wpweb2.tepper.cmu.edu/ceic/pdfs_other/Generating_Electricity_from_Renewables.pdf

[40] David Kay, *Land Use and Energy*, Cornell University, November 15, 2010, as cited in Paula Bernstein, *Alternative Energy: Facts, Statistics, and Issues*, 2001.

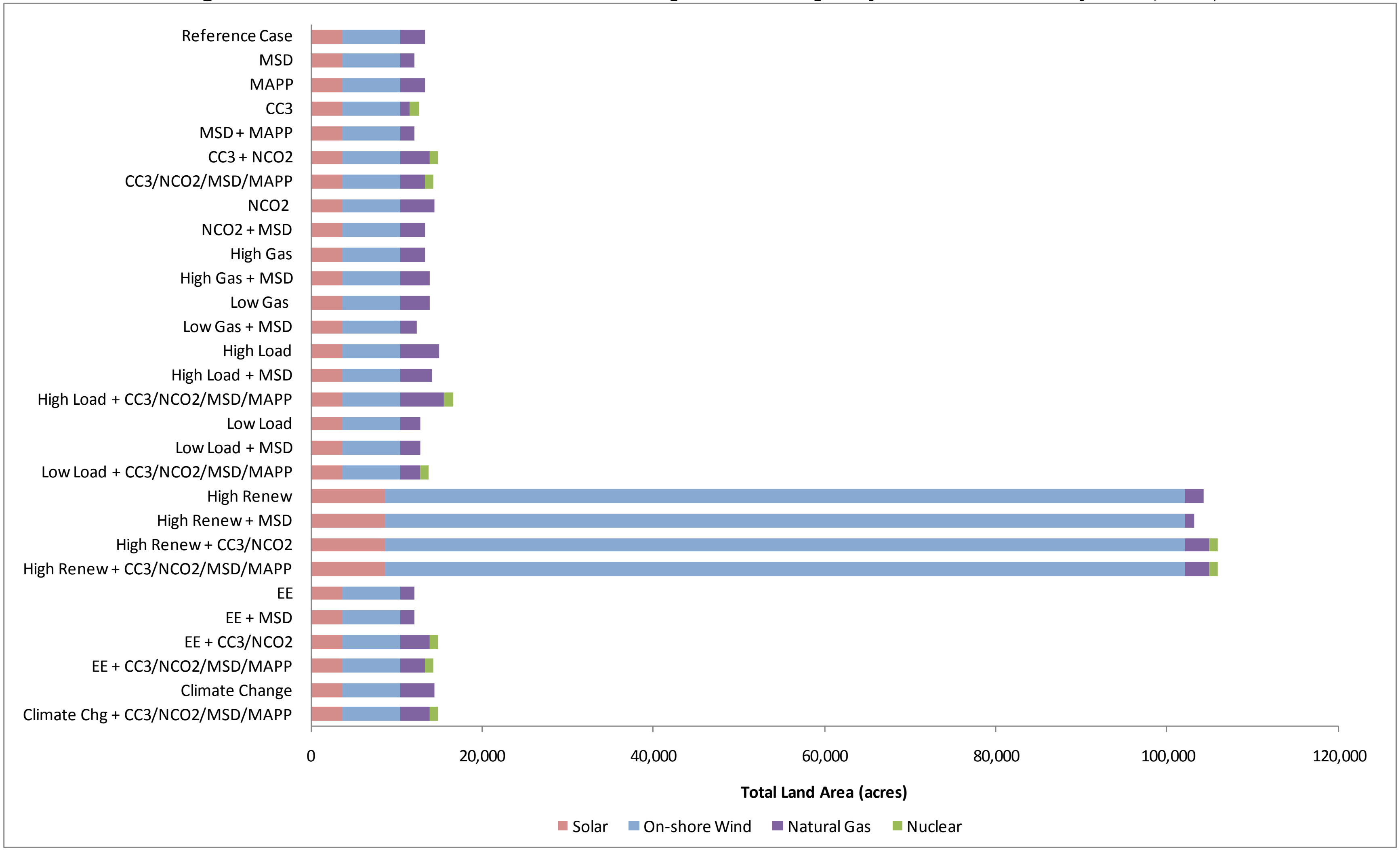
[41] Note that the levels of renewable energy capacity additions under the High Renewables scenarios are based on the assumption that the added RPS requirements will be met with in-State resources. To meet the Tier 1 Solar RPS requirement, the RECs must come from Maryland; however, wind energy and other Tier 1 Non-Solar resources may come from any state in the PJM geographical footprint.

filings with the Maryland PSC associated with the Calvert Cliffs Unit 3 licensing proceedings. Note that Calvert Cliffs 3 is envisioned to be constructed within the existing Calvert Cliffs site. The land that would be used for Calvert Cliffs 3, therefore, does not adversely affect potential alternative uses of land that would support Calvert Cliffs 3.

As explained above, there are widely ranging estimates regarding the amount of land required to generate electricity from alternative technologies simply because the actual amount of land needed is specific to the individual characteristics of each facility. For this reason, these estimates are utilized to approximate land use requirements for new capacity in Maryland, and should not be interpreted as a definitive assessment of land needed to support future electric generation.

Figure 13.31 shows that the High Renewables scenarios require approximately five times the area required under the LTER Reference Case and other scenarios. This difference is largely attributable to on-shore wind development under the High Renewables scenarios. It should be noted that land used for on-shore wind development can often be used for other purposes, for example, grazing or growing crops. To the extent that secondary uses can be accommodated on land designated for wind power development, land use impacts would be correspondingly diminished. There is very little difference in land use requirements among any of the other scenarios. The range of land use requirements among those scenarios is 15,000 to 18,000 acres.

Figure 13.31 Total Estimated Land Area Required for Capacity Additions in Maryland (acres)



*The land use requirements for the High Renewables scenarios shown in this table include the assumption that the additional on-shore wind power used to meet the higher Maryland RPS (the basis of the High Renewables scenarios) is sited in Maryland. To the extent that the additional on-shore wind resources are sited in other PJM states, Maryland land use requirements under these scenarios would be lower.

13.11 Summary Rankings

This section is designed to help interested parties rank the outcomes of the supply scenarios presented in this report. Ranking the scenarios is not a trivial undertaking because selecting the “best” supply option requires some subjective judgments. Some may place the greatest emphasis on relative costs of each scenario while others may be more concerned with the environmental implications of each scenario. Others still may have an interest in seeing increased energy efficiency and a greater investment in renewable energy technology, regardless of the cost. Given these disparate interests it is impossible to select a uniformly “best” scenario and as such this section presents rankings of several key metrics rather than a single ranking across scenarios.

Table 13.17 ranks the total production costs, wholesale energy market revenues and capacity revenues of PJM generators over the study period. The total production costs over the 20-year study period (in 2010 dollars) are calculated as the sum of fuel, fixed, variable, and emissions costs that generators in PJM incur to produce electricity. The scenarios with total production costs that are ranked in the top third (66th through 100th percentile) amongst the scenarios are denoted with a fully-shaded circle. The scenarios with production costs ranked in the middle third (33rd through 66th percentile) are denoted with a half-shaded circle. Finally, the scenarios with total production costs that are ranked in the bottom third (0 through 33rd percentile) contain an open circle in the total production cost column. The LTER Reference Case production costs are approximately $596 billion, which is ranked in the middle third amongst the scenarios.

The High Load scenario with Calvert Cliffs 3, national carbon legislation, and the MSD and MAPP lines has the highest production costs at $822.5 billion, which is almost fifty percent higher than the $551.7 billion in production costs associated with the Low Load and MSD scenario. Both Table 13.17 and Figure 13.27 demonstrate that introducing national carbon legislation has significant implications for total production costs. Introducing national carbon legislation increases total production costs by at least $152 billion relative to the LTER Reference Case in the scenarios that use the LTER Reference Case load growth assumptions. With high and low load growth, national carbon legislation along with Calvert Cliffs 3, MSD and MAPP increase total production costs by $226 billion and $102 billion, respectively.

Table 13.17
PJM-Wide Cost and Revenue by Scenario

	Total Production Costs	Wholesale Energy Revenues	Capacity Revenues
Reference Case	◑	◑	◑
MSD	◑	○	◑
MAPP	◑	◑	●
CC3	○	○	○
MSD + MAPP	◑	◑	◑
CC3 + NCO2	●	●	◑
CC3/NCO2/MSD/MAPP	●	●	○
NCO2	●	●	◑
NCO2 + MSD	●	●	◑
High Gas	◑	●	○
High Gas + MSD	◑	●	○
Low Gas	○	○	●
Low Gas + MSD	○	○	●
High Load	◑	◑	●
High Load + MSD	◑	◑	●
High Load + CC3/NCO2/MSD/MAPP	●	●	●
Low Load	○	○	○
Low Load + MSD	◑	○	○
Low Load + CC3/NCO2/MSD/MAPP	◑	◑	○
High Renew	○	○	◑
High Renew + MSD	○	◑	◑
High Renew + CC3/NCO2	●	●	◑
High Renew + CC3/NCO2/MSD/MAPP	●	●	○
EE	○	○	○
EE + MSD	○	○	◑
EE + CC3/NCO2	●	◑	●
EE + CC3/NCO2/MSD/MAPP	●	◑	●
Climate Change	◑	◑	●
Climate Chg + CC3/NCO2/MSD/MAPP	●	●	●
● = top third	◑ = middle third	○ = bottom third	

*Fuel diversity indices are ranked as follows: ● = < 0.88 ◑ = ≥ 0.88 and ≤ 0.915 ○ = > 0.915

The second column of Table 13.17 ranks the wholesale energy market revenues that generators earned throughout the study period (in 2010 dollars). Wholesale energy market revenues range from approximately $836 billion in the Low Load scenario to $1.371 billion in the High Load scenario with Calvert Cliffs 3, national carbon legislation, MSD and MAPP. Wholesale energy market revenues are typically highest in the scenarios with national carbon legislation and/or high natural gas prices. Table 13.17 also ranks capacity market revenues earned by PJM generators over the study period (in 2010 dollars). Capacity market revenues are $148 billion in the LTER Reference Case and most of the alternative scenarios have total capacity market revenues in the $145-$152 billion range. Load growth is the most important driver of capacity market revenues. The three high load growth scenarios have the highest capacity market revenues by far and each high load growth scenario has capacity revenues in excess of $218 billion. Conversely, the three low load growth scenarios have capacity market revenues under $92 billion, which is at least $56 billion below the reference case.

Table 13.18 ranks the total NO_x, SO_2, and CO_2 emissions from PJM generation units. The rankings of the emissions across the three pollutants are fairly consistent. Scenarios with relatively high CO_2 emissions typically have high NO_x and SO_2 emissions. However, the total emissions of each pollutant do not vary widely across scenarios. The NO_x emissions vary within a 6.7 percent range, while SO_2 emissions vary across scenarios within only a 6.1 percent range. CO_2 emissions demonstrate slightly more variability across scenarios. The Low Load scenario has the highest total CO_2 emissions, which are 8.7 percent higher than the High Renewables + CC3/NCO2/MSD/MAPP scenario, which has the lowest CO_2 emissions.

Table 13.18
PJM-Wide Summary Emissions by Scenario

	Total NOx Emissions	Total SO_2 Emissions	Total CO_2 Emissions
Reference Case	●	●	●
MSD	●	●	◑
MAPP	●	●	●
CC3	◑	◑	◑
MSD + MAPP	◑	●	●
CC3 + NCO2	◑	○	○
CC3/NCO2/MSD/MAPP	○	◑	○
NCO2	◑	◑	◑
NCO2 + MSD	◑	◑	○
High Gas	●	●	●
High Gas + MSD	●	●	●
Low Gas	◑	○	◑
Low Gas + MSD	◑	○	◑
High Load	◑	●	◑
High Load + MSD	◑	◑	◑
High Load + CC3/NCO2/MSD/MAPP	○	◑	○
Low Load	●	◑	●
Low Load + MSD	●	◑	●
Low Load + CC3/NCO2/MSD/MAPP	○	○	○
High Renew	○	○	◑
High Renew + MSD	○	○	◑
High Renew + CC3/NCO2	○	○	○
High Renew + CC3/NCO2/MSD/MAPP	○	○	○
EE	●	●	●
EE + MSD	●	●	●
EE + CC3/NCO2	○	○	○
EE + CC3/NCO2/MSD/MAPP	○	◑	○
Climate Change	●	●	●
Climate Chg + CC3/NCO2/MSD/MAPP	◑	◑	◑

● = top third	◑ = middle third	○ = bottom third

*Fuel diversity indices are ranked as follows: ● = < 0.88 ◑ = ≥ 0.88 and ≤ 0.915 ○ = > 0.915

Table 13.19 ranks the fuel diversity indices and total generic gas capacity across the scenarios. The fuel diversity index is a measure of the mixture of fuels used to generate electricity in PJM. A higher fuel diversity index indicates greater fuel diversity.   The fuel diversity indices varied little across scenarios, ranging from 0.86 to 0.95 on a 0-to-1 scale. As such, we employed a different ranking technique but as before, the fully-shaded circles indicate the scenarios with the greatest fuel diversity, the half-shaded circles indicate the scenarios with mid-range fuel diversity, and the open circles indicate those scenarios with the least fuel diversity. The low load growth scenarios have the lowest fuel diversity because low load growth induces the fewest number of new generic natural gas plants. Fuel diversity is greatest in the high load growth and national carbon scenarios because they involve the highest amount of generic natural gas capacity additions.

Table 13.19 also ranks the total generic natural gas capacity (in MW) that was automatically built by the model to satisfy reliability requirements within PJM. This metric exhibits more variation than the fuel diversity index. Approximately 30 GW of generic natural gas capacity is built in the LTER Reference Case but only 8 GW is built in the Low Load scenario, and only 15.4 GW of gas capacity is built under the low load scenario with Calvert Cliffs 3, national carbon legislation, MSD, and MAPP. Scenarios with high load growth involve the highest levels of generic gas capacity additions and all of the high load growth scenarios have at least 51.8 GW of new natural gas capacity. National carbon legislation alone results in approximately 7 GW of additional generic gas capacity relative to the LTER Reference Case, while the high renewables and energy efficiency scenarios have generic natural gas builds that are 2-3 GW below the LTER Reference Case.

Table 13.19
PJM-Wide Summary Diversity and Capacity Additions by Scenario

	2030 Fuel Diversity Index*	Total Gas Capacity Built
Reference Case	◑	◑
MSD	◑	◑
MAPP	◑	◑
CC3	◑	○
MSD + MAPP	◑	◑
CC3 + NCO2	●	●
CC3/NCO2/MSD/MAPP	●	●
NCO2	●	●
NCO2 + MSD	●	●
High Gas	◑	◑
High Gas + MSD	◑	◑
Low Gas	◑	○
Low Gas + MSD	◑	◑
High Load	●	●
High Load + MSD	●	●
High Load + CC3/NCO2/MSD/MAPP	●	●
Low Load	○	○
Low Load + MSD	○	○
Low Load + CC3/NCO2/MSD/MAPP	◑	○
High Renew	◑	○
High Renew + MSD	◑	○
High Renew + CC3/NCO2	●	◑
High Renew + CC3/NCO2/MSD/MAPP	●	●
EE	◑	○
EE + MSD	◑	○
EE + CC3/NCO2	●	◑
EE + CC3/NCO2/MSD/MAPP	●	◑
Climate Change	◑	●
Climate Chg + CC3/NCO2/MSD/MAPP	●	●

● = top third ◑ = middle third ○ = bottom third

*Fuel diversity indices are ranked as follows: ● = < 0.88 ◑ = ≥ 0.88 and ≤ 0.915 ○ = > 0.915