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PPRP

Long-term

Electricity Report

for Maryland

December 1, 2011

MARYLAND POWER PLANT
RESEARCH PROGRAM

Martin O'Malley, Governor ♦ Anthony G. Brown, Lt. Governor

The Maryland Department of Natural Resources (DNR) seeks to preserve, protect and enhance the living resources of the State. Working in partnership with the citizens of Maryland, this worthwhile goal will become a reality. This publication provides information that will increase your understanding of how DNR strives to reach that goal through its many diverse programs.

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Long-Term Electricity Report for Maryland

Prepared for the
Maryland Department of Natural Resources
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Pursuant to Executive Order 01.01.2010.16

Prepared by
Exeter Associates, Inc.

December 1, 2011

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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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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 given the State's 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, an 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 Case is based on a set of assumptions and projections assessed as a plausible view of the current 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 addition to the alternative scenarios noted above, Table ES.1 also identifies four scenarios developed in response to comments received on earlier drafts of the LTER. These supplemental responsive scenarios address the construction of a natural gas plant in advance of reliability requirements; high levels of coal plant retirements related to implementation of EPA regulations (two scenarios); and a combination of external circumstances emerging that could

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

serve to threaten power supply reliability in Maryland. The results of the Supplemental Responsive Scenarios are presented in Appendix L. In total, 38 alternative scenarios are defined and analyzed.

We emphasize that the fundamental purpose of this report is to provide Maryland policy-makers with an assessment of estimated impacts on Maryland's electric power sector resulting from a wide range of possible future circumstances. The report should not be interpreted as a policy document or an integrated resource plan.

The outcomes of the LTER Reference Case, as well as those of the 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 scenario results represent a narrow evaluation focusing primarily on economic and environmental 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, overall economic development, and improvements in public health, welfare, and quality of life.

Over the course of 20 years, there may also be substantial technological advances that would affect the modeling results in a variety of ways. Technological advances in economic storage technologies, for example, would allow intermittent renewable resources to be dispatchable. Other areas of potential technological advances that could dramatically alter the modeling results include: advances in renewable energy technologies could serve to significantly reduce the cost of renewable energy on a per kWh basis over the life of the renewable project; advances in plug-in electric vehicles (or the supporting infrastructure) could permit increases in system load factors, use of plug-in electric vehicles as decentralized storage devices, and significantly increase growth in system load; and advances in emissions control technologies would result in lower rates of emissions at reduced cost. Speculation on potential technological advances over the 20-year study period, however, are beyond the scope of this analysis. As technological advances emerge, they will be captured in subsequent cycles of the LTER.

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 and 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_2 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 RC assumptions.
	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. Other RC assumptions unchanged.
	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.
New EPA Regulations Scenarios	Proposed Environmental Protection Agency (“EPA”) Regulations with Mt. Storm to Doubs	The new EPA regulations for cooling water, NO_x and SO_2, plus MSD added to the RC.
	Proposed Environmental Protection Agency (“EPA”) Regulations with Mt. Storm and MAPP	The new EPA regulations for cooling water, NO_x and SO_2, plus both MSD and MAPP added to the RC.
PPRAC-Identified 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. Other RC assumptions unchanged.
	Aggressive Energy Efficiency and High Renewables and Mt. Storm to Doubs	A combination of the aggressive EE and high renewables assumptions in Maryland, plus MSD added to the RC.
	Medium Renewables Scenario and Mt. Storm to Doubs	An increase in the Maryland RPS requirement midway between the RC and the High Renewables scenario, plus MSD.

Category	Scenarios	Description
Supplemental Scenarios (Responsive)[2]	Early Natural Gas Plant	A combined cycle natural gas plant is constructed in Maryland in 2016 and added to the LTER Reference Case plus Mt. Storm to Doubs assumptions.
	Combined Events	The scenario includes the LTER Reference Case plus reduced demand response, moderately rapid growth in loads, low natural gas prices, implementation of EPA regulations, and significant retirement of coal plants in PJM.
	EPA Scenario with High Coal Plant Retirements	The new EPA regulations for cooling water, NO_x, SO_2, and mercury, plus high PJM coal plant retirements and the Mt. Storm to Doubs transmission line upgrade.
	EPA Scenario with Very High Coal Plant Retirements	The new EPA regulations for cooling water, NO_x, SO_2, and mercury, plus very high PJM coal plant retirements and the Mt. Storm to Doubs transmission line upgrade.

For each scenario, 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.

[2] These supplemental scenarios were run in response to public comments.

All of the modeling input assumptions, for both the LTER Reference Case and the alternative scenarios, were presented to the Power Plant Research Advisory Committee ("PPRAC") for comment and feedback. PPRAC is an advisory body to the Secretary of Maryland Department of Natural Resources. PPRAC members are appointed by the Secretary and include representatives from State government agencies, environmental organizations, Maryland electric utilities, independent power producers, and Maryland academic institutions.

Parties expressing an interest in the development of the LTER were also included in the group from which comments on the LTER inputs (and results) were solicited. Interested Parties included renewable project developers, private citizens, PJM representatives, environmental groups, and others.[3]

PPRP received extensive comments from both PPRAC members and Interested Parties, which proved to be extremely helpful in developing the LTER. To the maximum extent possible, PPRP employed a transparent process in developing the LTER to facilitate meaningful input from PPRAC and Interested Parties. All comments received throughout the LTER development process were reviewed and responses provided.[4]

[3] A list of PPRAC members and Interested Parties is included in Appendix M.
[4] Comments and responses are provided in Appendix H.

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 power 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; and 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 is assumed to 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) are 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.
New EPA Regulations	Proposed EPA regulations on once-through cooling water are added to the model as per the costs developed by NERC. NO_x and SO_2 regulations updated to comply with the newly released Cross-State Air Pollution Rule.
PJM Aggressive Energy Efficiency	PJM-wide aggressive energy efficiency is calculated for all states in PJM with existing programs in the same manner as for Maryland.
Medium Renewables	Medium renewables scenario includes renewables development levels between High and LTER References Case renewables development levels.
Coal Plant Life Extension	Coal plants with rated capacity at 400 MW or more that have not announced retirement plans had their useful lives extended past the end of the study period.
Supplemental Responsive Scenarios: High Coal Plant Retirements	An additional 11,000 MW (approximately) of PJM coal plants are assumed to retire by 2015 and about 3,000 MW of non-coal power plants.
Supplemental Responsive Scenarios: Very High Coal Plant Retirements	An additional 22,000 MW (approximately) of PJM coal plants are assumed to retire by 2015 and about 3,000 MW of non-coal power plants.
Supplemental Responsive Scenarios: Early Natural Gas Plant Addition	A combined cycle natural gas plant is assumed to be constructed in Maryland in 2016.
Supplemental Responsive Scenarios: Moderate Load Growth and Reduced Demand Response (Combined Events)	Load under the moderate load growth assumption is halfway between LTER Reference Case and High Load Growth assumptions. Demand response in PJM reaches a maximum of about 12 GW in 2015 and is held constant thereafter.

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 Maryland energy consumption; wholesale 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 service 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").[5] Some of the modeling results, therefore, are at the zonal level.

General Results

Several conclusions can be drawn from the body of results over all of the scenarios analyzed in the LTER. The general findings include:

- For most scenarios, no new generation capacity is needed in PJM to meet reliability requirements until about 2018. For scenarios using more conservative assumptions, no new generation is needed until 2015, and for scenarios using more optimistic assumptions, generation is not needed until about 2022.
- For most scenarios, no new generation capacity is needed in Maryland to meet reliability requirements until 2019 or 2020. For scenarios using more conservative assumptions, no new generation in needed until 2015, and for scenarios using more optimistic assumptions, no new generation is needed until 2023.
- Based on least-cost criteria, all new plants added by the model for reliability are fueled by natural gas under all scenarios.
- Renewable generation is added as an input into the model to satisfy state RPS requirements; in some scenarios, on-shore wind power becomes price-competitive with conventional resources near the end of the analysis period.

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[5] 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.

- Construction of the Mt. Storm to Doubs ("MSD") transmission upgrade and/or construction of the MAPP transmission line have no significant effect on total PJM power plant additions.
- Construction of the MSD transmission upgrade does affect the total number of power plants built in Maryland but construction of the MAPP transmission line does not.
- Natural gas prices and implementation of national carbon legislation are the two most important factors affecting energy prices.
- Under all scenarios, fuel diversity in PJM increases over time as more natural gas plants and renewables are added to the supply mix.
- With respect to criteria air emissions (NO_x, SO_2, and mercury), the PJM fleet as a whole reduces emissions over time with the addition of new more efficient, cleaner power plants.
- For all scenarios, the Maryland Healthy Air Act limits are met.
- Consumption-based CO_2 emissions are most importantly affected by national carbon legislation, the aggressiveness of the RPS, the aggressiveness of the energy efficiency programs, and the pace of load growth.
- For most scenarios, Maryland continues to be a net importer of electricity throughout the analysis period.

LTER REFERENCE CASE RESULTS

- No new generating capacity is added in PJM to meet reliability requirements before 2020. Between 2010 and 2030, PJM adds approximately 30,000 MW of new natural gas-fired capacity and 16,250 MW of renewable generating 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.
- 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.
- 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.[6]

- Real energy prices are projected to increase 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 offset 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 $300 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. In the LTER Reference Case, 30,000 MW of new gas-fired generating capacity is added to PJM by 2030.
- In addition to the 30,000 MW of new natural gas-fired generation added to PJM in 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.

[6] RGGI is scheduled to expire in 2019. The LTER includes the assumption that RGGI will be extended (at 2019 levels) through the end of the 20-year analysis period.

- The implementation of new EPA regulations results in the construction of an additional 4 GW of new natural gas capacity because approximately 4.3 GW of existing capacity retires as a result of the assumed new regulations.
- With the assumption of 14,000 MW of power plant retirements (about 11,000 MW of the 14,000 MW are coal-fired plants) in PJM due to implementation of new EPA regulations, an additional 6,000 MW of new natural gas-fired capacity is added to PJM by 2030 relative to the LTER Reference Case plus Mt. Storm to Doubs.
- With the assumption of an additional 25,000 MW of power plant retirements (about 23,000 MW are coal-fired plants) in PJM due to implementation of new EPA retirements, an additional 13,000 MW of new natural gas-fired capacity is added to PJM by 2030 relative the LTER Reference Case plus Mt. Storm to Doubs.

<u>Energy Prices</u>

- Wholesale energy prices under most alternative scenarios are generally consistent with the LTER Reference Case energy prices with two exceptions – the 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.
- The assumed new EPA regulations result in a transitory wholesale energy price increase between 2015, when the regulations take effect, and 2019. Prices converge with the LTER Reference Case plus MSD scenario in 2020 and beyond.
- Under assumptions of new EPA regulations with high (and very high) levels of coal plant retirements in PJM, wholesale energy prices increase between 2015 and 2018 relative to the LTER Reference Case plus MSD, then decline below the LTER Reference Case plus MSD prices through 2026. These results are due to signficiant retirements of relatively low-cost coal-fired generation in 2015, followed by construction of new, efficient gas-fired generation. By the end of the analysis period,

sufficient new efficient natural gas-fired generation has been constructed under the Reference Case plus MSD scenario to result in energy prices that mirror those in the scenarios that incdule new EPA regulations combined with high (and very high) coal-plant retirements. Between 2027 and 2030, the EPA scenarios with high and very high coal plant retirements show prices roughly equivalent to the LTER Reference Case plus MSD prices.

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). (Note: total PJM CO_2 emissions are slightly reduced by about 4.7 million tons; 0.9 percent.)
- The introduction of national carbon legislation reduces CO_2 emissions in Maryland by approximately 8 percent (3 million tons per year) by 2030. (Note: total PJM CO_2 emissions drop significantly by about 117.2 million tons; 21 percent.)
- 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 CO_2 emissions 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.
- Both of the scenarios with proposed new EPA regulations involve lower SO_2 and NO_x emissions relative to the LTER Reference Case. With the assumed new EPA regulations, CO_2 emissions are seven percent lower than the LTER Reference Case plus the Mt. Storm to Doubs transmission upgrade, and CO_2 emissions increase by one percent relative to the LTER Reference Case if both the Mount Storm to Doubs and MAPP projects are built because the MAPP line involves the addition of more incremental gas capacity in Maryland.
- The Supplemental Responsive Scenarios related to new EPA regulations plus MSD and high (and very high) PJM coal plant retirements entail lower Maryland generation-based SO_2 and NO_x emissions relative to the LTER Reference Case plus MSD beginning in 2015 and extending to the end of the study period. Generation-based CO_2 emissions in Maryland are higher under the Supplemental Responsive EPA Scenarios over the 2015 through 2021 period relative the LTER Reference Case plus MSD scenario due to Maryland coal plants running at higher capacity factors during this period and the increase in new natural gas capacity builds compared to the LTER Reference Case plus MSD scenario. After 2021, generation-based CO_2 emissions in Maryland are either slightly above (very high coal plant retirements) or slightly below (high coal plant retirements) the generation-based Maryland CO_2 emissions shown for the LTER Reference Case plus MSD scenario due to higher levels of generation from natural gas plants in the State which offset the reductions in CO_2 emissions from retired coal plants.

Maryland Emissions Based on Maryland Consumption

- Emissions of CO_2, SO_2, NO_x, and mercury are highest (relative to the LTER Reference Case) under the high load growth scenario, as fossil-fueled generating units are run more intensively to meet higher levels of demand. Emissions levels are also higher than the LTER Reference Case under the plant life extension scenario and the high gas price scenarios since there are fewer retirements of coal fired facilities and coal generation runs more intensively.
- The lowest levels of emissions are primarily associated with the high renewables scenarios, the energy efficiency scenarios, the national carbon legislation scenarios, the low natural gas price scenarios, the low load growth scenarios, and the scenarios that include construction of Calvert Cliffs 3 combined with national carbon legislation. Emissions of NO_x, however, are lowest under the scenarios that include the proposed EPA regulations.

- In general, there is not a large degree of variation in total consumption-based emissions among the scenarios. Emissions levels in most scenarios are within 5 percentage points of the LTER Reference Case; however some scenarios have emissions levels that are about 10 percent lower than in the LTER Reference Case. The Supplemental Responsive Scenarios that include the new EPA regulations shows higher percentage declines for SO_2, NO_x, and CO_2 resulting from the retirement of significant levels of coal-fired capacity.
- Maryland's Greenhouse Gas Reduction Act ("GGRA") specifies a 25 percent reduction in State-wide greenhouse gases by 2020 relative to a 2006 baseline. The CO_2 reductions required by each of several business sectors will not be finalized until December 2012; consequently, the magnitude of the reductions for the electricity sector (based on consumption) could not be assessed against the GGRA sector CO_2 reduction requirement. In lieu of that calculation, consumption-based CO_2 emissions were evaluated against the 2006 baseline developed by the Maryland Department of the Environment. For all scenarios for all years of the study period, CO_2 emissions are below the baseline. By 2020, percentage reduction from the 2006 baseline range from 12.0 percent to 27.7 percent, depending on the scenario considered. In general, the scenarios exhibiting the largest reductions in CO_2 emissions relative to the baseline include the assumption of national carbon legislation being in place. The scenarios exhibiting the smallest reductions relative to the baseline are those scenarios characterized by high load growth. By 2030, the percentage reductions in CO_2 emissions relative to the 2006 baseline range from 4.2 percent to 37.4 percent, depending on the scenario considered.

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 most scenarios are between 12,000 and 15,000 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. Under the Medium Renewables scenario, land use requirements in Maryland exceed 50,000 acres during the study period. Almost all of the requirements are related to the development of on-shore wind generation.[7]

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 $12 per REC by 2030.
- For the scenarios that entail significantly higher energy prices than projected for the LTER Reference Case (for example, the cases that include national carbon legislation and high natural gas prices), the projected REC prices (2010$) are lower than in the LTER Reference Case and drop to zero towards the end of the study period. The reason for this result is that the REC prices are calculated as the residual revenue required by a

[7] For the High and Medium 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 and Medium Renewables scenarios would be sited outside Maryland, the Maryland land use requirements estimated for these scenarios would be correspondingly lower.

new renewable energy project to cover all costs of ownership and operation. Revenue sources include energy revenue, capacity revenue, 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 REC prices.

- The low natural gas price scenarios result in the highest projected REC prices due to the low energy prices projected for these scenarios. Nominal REC 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 REC prices, nominal REC prices were assumed to reach a maximum of $38 per REC, with the $2-per-REC difference between the $40 ACP and the $38 assumed maximum value representing REC-market transaction costs. In real terms, REC prices under the low natural gas price scenarios reach $33 per REC in 2013, and decline to $23 per REC in 2030.

Comparing Scenarios

Table ES.4, below, is included to help guide the comparisons of scenarios and facilitate the isolation and identification of impacts associated with specific economics, regulatory, or policy changes. Chapter references are also provided in the table.

Table ES.4 Comparison of Scenarios

Topic	Description	Scenarios to Compare to Assess Marginal Impacts	LTER Reference
Calvert Cliffs Unit 3	To assess the impacts of constructing Calvert Cliffs 3	Reference Case (RC) Calvert Cliffs 3 Scenario (CC3)	Chapter 5
Mt. Storm to Doubs transmission upgrade	To assess the impacts of upgrading the Mt. Storm to Doubs transmission line	Reference Case (RC) Mt. Storm to Doubs Scenario (MSD)	Chapter 5
MAPP transmission line	To assess the impacts of building the MAPP transmission line	Reference Case (RC) MAPP Scenario (MAPP)	Chapter 5
Transmission	To assess the impacts of a transmission build-out which involves the upgrade of Mt. Storm to Doubs and construction of MAPP	Reference Case (RC) MAPP and Mt. Storm to Doubs Scenario (MSD+MAPP)	Chapter 5
Infrastructure	To assess the impacts of building Mt. Storm to Doubs, MAPP, and Calvert Cliffs 3 under national carbon legislation	Reference Case (RC) Reference Case plus Mt. Storm to Doubs, MAPP, Calvert Cliffs 3, and National Carbon Legislation Scenario (CC3/NCO2/MSD/MAPP)	Chapter 5
National Carbon Legislation	To assess the impacts of carbon legislation on construction of Calvert Cliffs 3	Reference Case plus Calvert Cliffs 3 (CC3) Calvert Cliffs 3 and National Carbon Legislation Scenario (CC3+NCO2)	Chapter 5
National Carbon Legislation	To assess the impacts of national carbon legislation	Reference Case (RC) National Carbon Legislation Scenario (NCO2)	Chapter 6
National Carbon Legislation	To assess the impacts of adding national carbon legislation to a system the includes the Mt. Storm to Doubs transmission upgrade	Mt. Storm to Doubs Alternative Scenario (MSD) Mt. Storm to Doubs and National Carbon Legislation Scenario (NCO2+MSD)	Chapter 6

Topic	Description	Scenarios to Compare to Assess Marginal Impacts	LTER Reference
Natural Gas Prices	To assess the impacts associated with relatively high natural gas prices	Reference Case (RC) High Price Natural Gas Scenario (HPNG)	Chapter 7
Natural Gas Prices	To assess the impacts associated with relatively low natural gas prices	Reference Case (RC) Low Price Natural Gas Scenario (LPNG)	Chapter 7
Natural Gas Prices	To assess the impacts of upgrading Mt. Storm to Doubs under relatively high natural gas prices	High Price Natural Gas Scenario (HPNG) High Price Natural Gas plus Mt. Storm to Doubs Scenario (HPNG+MSD)	Chapter 7
Natural Gas Prices	To assess the impacts of building Mt. Storm to Doubs under relatively low natural gas prices	Low Price Natural Gas Scenario (LPNG) Low Price Natural Gas plus Mt. Storm to Doubs Scenario (LPNG+MSD)	Chapter 7
Load Growth	To assess the impacts associated with relatively rapid growth in load	Reference Case (RC) High Load Scenario (HL)	Chapter 8
Load Growth	To assess the impacts associates with relatively slow growth in load	Reference Case (RC) Low Load Scenario (LL)	Chapter 8
Load Growth	To assess the impacts of upgrading Mt. Storm to Doubs under relatively rapid load growth	High Load Scenario (HL) High Load plus Mt. Storm to Doubs Scenario (HL+MSD)	Chapter 8
Load Growth	To assess the impacts associated with upgrading Mt. Storm to Doubs under relatively slow growth in load	Low Load Scenario (LL) Low Load plus Mt. Storm to Doubs Scenario (LL+MSD)	Chapter 8
Load Growth	To assess the impacts of infrastructure changes under relatively rapid load growth	High Load Scenario (HL) High Load plus Mt. Storm to Doubs, MAPP, Calvert Cliffs 3, and National Carbon Legislation Scenario (HL /CC3/NCO2/MSD/MAPP)	Chapter 8
Load Growth	To assess the impacts of infrastructure changes under relatively slow load growth	Low Load Scenario (LL) Low Load plus Mt. Storm to Doubs, MAPP, Calvert Cliffs 3, and National Carbon Legislation Scenario (LL/CC3/NCO2/MSD/MAPP)	Chapter 8

Topic	Description	Scenarios to Compare to Assess Marginal Impacts	LTER Reference
High Renewables	To assess the impacts of increasing the Maryland RPS to 30 percent and meeting that increase with in-state resources	Reference Case (RC) High Renewables Scenario (HREN)	Chapter 9
High Renewables	To assess the impacts associated with upgrading Mt. Storm to Doubs under a 30 percent Maryland RPS	High Renewables Scenario (HREN) High Renewables plus Mt. Storm Scenario (HREN+MSD)	Chapter 9
High Renewables	To assess the impact of Calvert Cliffs 3 and national carbon legislation under a 30 percent Maryland RPS	High Renewables Scenario (HREN) High Renewables plus Calvert Cliffs 3 and National Carbon Legislation Scenario (HREN/CC3/NCO2)	Chapter 9
High Renewables	To assess the impacts of infrastructure changes under a 30 percent Maryland RPS	High Renewables Scenario (HREN) High Renewables plus Mt. Storm, MAPP, Calvert Cliffs 3 and National Carbon Legislation Scenario (HREN/CC3/NCO2/MSD/MAPP)	Chapter 9
Energy Efficiency	To assess the impacts of Maryland fully meeting the EmPOWER Maryland goals	Reference Case (RC) Aggressive Energy Efficiency Scenario (EE)	Chapter 10
Energy Efficiency	To assess the impacts associated with upgrading Mt. Storm to Doubs under higher Maryland energy efficiency	Aggressive Energy Efficiency Scenario (EE) Aggressive Energy Efficiency plus Mt. Storm to Doubs Scenario (EE+MSD)	Chapter 10
Energy Efficiency	To assess the impacts of Calvert Cliffs 3 and national carbon legislation under higher Maryland energy efficiency	Aggressive Energy Efficiency Scenario (EE) Aggressive Energy Efficiency plus Calvert Cliffs 3 and National Carbon Legislation Scenario (EE/CC3/NCO2)	Chapter 10
Energy Efficiency	To assess the impacts of infrastructure changes under higher Maryland energy efficiency	Aggressive Energy Efficiency Scenario (EE) Aggressive Energy Efficiency plus Mt. Storm, MAPP, Calvert Cliffs 3 and National Carbon Legislation Scenario (EE/CC3/NCO2/MSD/MAPP)	Chapter 10
Climate Change	To assess the impacts of increasing temperatures due to climate change	Reference Case (RC) Climate Change Scenario (CC)	Chapter 11

Topic	Description	Scenarios to Compare to Assess Marginal Impacts	LTER Reference
Climate Change	To assess the impacts of infrastructure changes under increasing temperatures due to climate change	Climate Change Scenario (CC) Climate Change plus Mt. Storm, MAPP, Calvert Cliffs 3 and National Carbon Legislation Scenario (CC/CC3/NCO2/MSD/MAPP)	Chapter 11
Proposed EPA Regulations	To assess the impacts of the proposed EPA regulations on a system that includes the Mt. Storm to Doubs transmission upgrade	Mt. Storm to Doubs Scenario (MSD) EPA Regulations plus Mt. Storm to Doubs Scenario (EPA Reg+ MSD)	Chapter 12
Proposed EPA Regulations	To assess the impacts of the proposed EPA regulations coupled with transmission system expansion	Mt. Storm to Doubs Scenario (MSD) EPA Regulations plus Mt. Storm to Doubs and MAPP Scenario (EPA Reg+ MSD/MAPP)	Chapter 12
Proposed EPA Regulations	To assess the impacts of additional levels of power plant retirements in PJM.	EPA Regulations plus Mt. Storm to Doubs Scenario (EPA Reg+ MSD) EPA Regulations plus Mt. Storm to Doubs plus Additional Power Plant Retirements Scenarios (EPA/MSD/AR1 and EPA/MSD/AR2)	Appendix L
Load Growth plus PJM-wide Energy Efficiency	To assess the combined impacts of relatively slow load growth plus aggressive PJM-wide energy efficiency	Reference Case (RC) Low Load plus PJM-Wide Energy Efficiency Scenario (LL+PJM EE)	Chapter 12
Medium Renewables	To assess the impacts of a mid-level Maryland renewable energy build-out on a system that includes the Mt. Storm to Doubs transmission upgrade	Mt. Storm to Doubs Scenario (MSD) Medium Renewables plus Mt. Storm to Doubs Scenario (MREN+MSD)	Chapter 12
Medium Renewables	To assess the differences between the Maryland high renewables build-out and the medium renewables build-out	Medium Renewables plus Mt. Storm to Doubs Scenario (MREN+MSD) High Renewables plus Mt. Storm to Doubs Scenario (HREN+MSD)	Chapter 12

Topic	Description	Scenarios to Compare to Assess Marginal Impacts	LTER Reference
High Energy Efficiency and High Renewables	To assess the combined impacts of fully achieving the EmPOWER Maryland goals and a 30 percent Maryland RPS met with in-state resources	Mt. Storm to Doubs Scenario (MSD) Mt. Storm to Doubs plus Aggressive Energy Efficiency and High Renewables Scenario (HREN+EE/MSD	Chapter 12
Coal Plant Life Extension	To assess the impacts of extending the life of potentially profitable coal plants	Mt. Storm to Doubs Scenario (MSD) Mt. Storm to Doubs plus Coal Plant Life Extension Scenario (Life Xtsn+MSD)	Chapter 12
Early Natural Gas Plant Construction	To assess the impacts of building a natural gas plant in Maryland in 2015	Mt. Storm to Doubs Scenario (MSD) Mt. Storm to Doubs plus Early Natural Gas Plant Scenario (NGP+MSD)	Appendix L
Combined Events Adversely Affecting Maryland Reliability of Supply	To assess the impact of higher than expected load growth, lower than expected demand response, EPA regulations, and additional coal plant retirements	Mt. Storm to Doubs Scenario (MSD) Mt. Storm to Doubs plus Combined Events Scenario (CE+MSD)	Appendix L
Coal Prices	To assess the impacts of higher coal prices	Reference Case (RC) Low Price Natural Gas Scenario (LPNG) (A low coal price scenario was not run but the LPNG scenarios would provide impacts associated with a change in the gas price-to-coal price ratio.)	Chapter 7
Coal Prices	To assess the impacts of lower coal prices	Reference Case (RC) High Price Natural Gas Scenario (HPNG) (A high coal price scenario was not run but the HPNG scenarios would provide impacts associated with a change in the gas price-to-coal price ratio.)	Chapter 7

Summary

Table ES.5 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 and are not the same as capital costs, which is only the cost of constructing a facility. The fixed and variable costs include operation and maintenance ("O&M") expenses as well as emissions costs. As shown in the total production cost column of Table ES.5, the scenarios that include implementation of national carbon legislation involve the highest total production costs.

The second column of Table ES.5 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.5 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 and low natural gas prices.

Table ES.5 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 is generally stable, and scenarios with relatively high CO_2 emissions typically also have high NO_x and SO_2 emissions. The seventh column in Table ES.5 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.5 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.5 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	●	●	●	◑	◑	◑	●	●
EPA Reg + MSD	◑	◑	●	○	◑	◑	◑	◑
EPA Reg + MSD/MAPP	◑	◑	●	○	◑	◑	◑	◑
Low Load + PJM EE	○	○	○	○	○	○	○	○
Med Renew + MSD	○	○	◑	◑	◑	●	◑	◑
High Renew + EE/MSD	○	○	○	◑	◑	◑	◑	○
Life Xtsn + MSD	◑	○	○	●	●	●	◑	○
Early Natural Gas Plant	◑	○	●	●	●	●	◑	◑
Combined Events	○	○	●	○	○	○	●	●
EPA/MSD/AR1	◑	◑	●	○	○	◑	◑	●
EPA/MSD/AR2	◑	◑	●	○	○	○	●	●

● = 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.[8] 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:

- 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

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

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;
- Maryland 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 current PJM system 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.[9]

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.

Step 2. Define an 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. 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 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 that could emerge over the 20-year study period and affect projected costs[10], 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, 34 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 34 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, and 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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[9] The method by which transmission system capabilities are reflected in the analysis is discussed in detail in Chapter 2 of the LTER.
[10] External factors include 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") [11] 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.) Comments and responses are also included in Appendix H of this report.

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 correctly employing the input assumptions provided, the LTER Reference Case and the 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 the outputs provided by the models. The chapter also discusses the limitations specific to the models.

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[11] 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.

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:[12]

- 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 ("REC") 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.

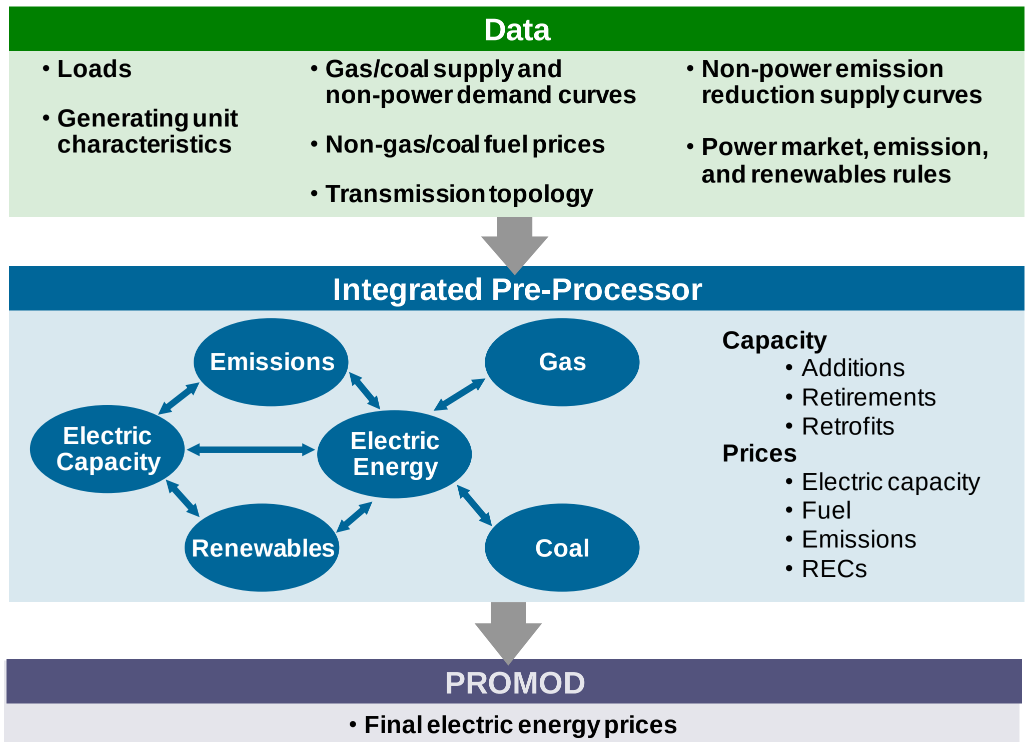
[12] The Ventyx reference case is Ventyx's baseline national projection. This projection differs from the LTER Reference Case which is based on certain Maryland-specific and PJM-specific data developed by PPRP, current legislation, and most plausible projections of other relevant factors. The specifications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

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.

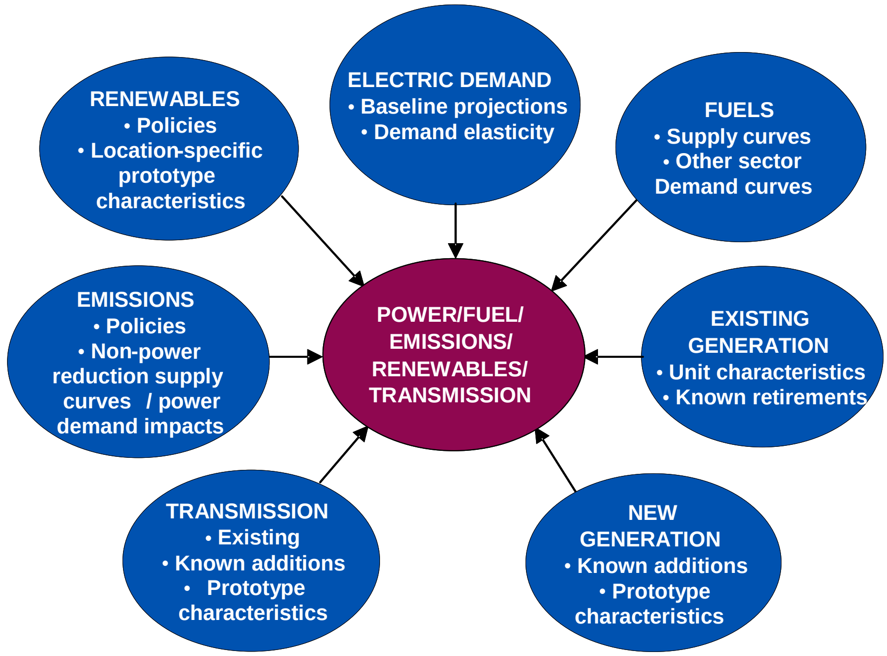
Figure 2.1 Forecasting Process



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 online. In the second phase, generic units are brought online 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.

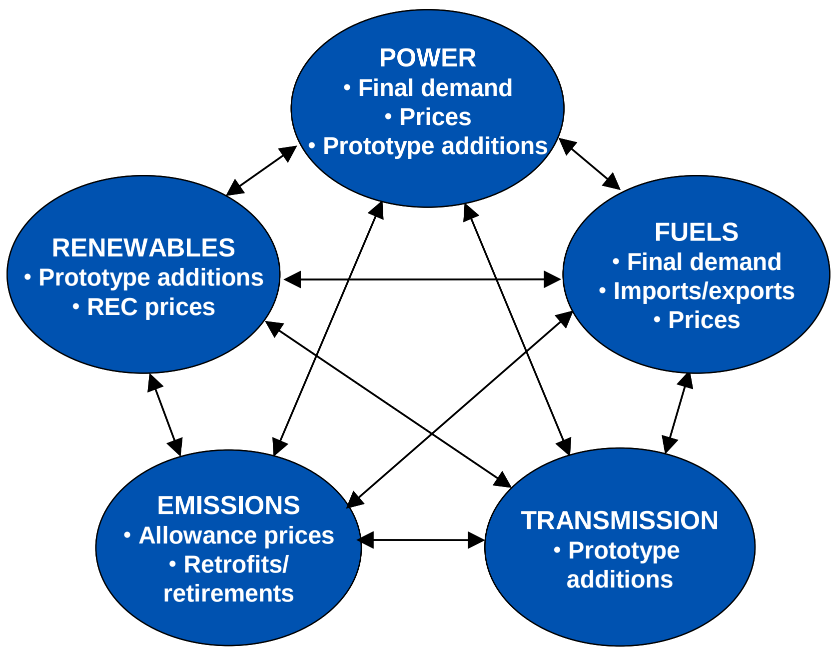
In order to meet future needs for new generating capacity, the LTER considers nine types of generic conventional resources during the 20-year forecast period. New resources are added in response to forecast electric demand, whereby the added capacity is economically viable and the reserve margins are 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 in detail in Chapter 3, 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.

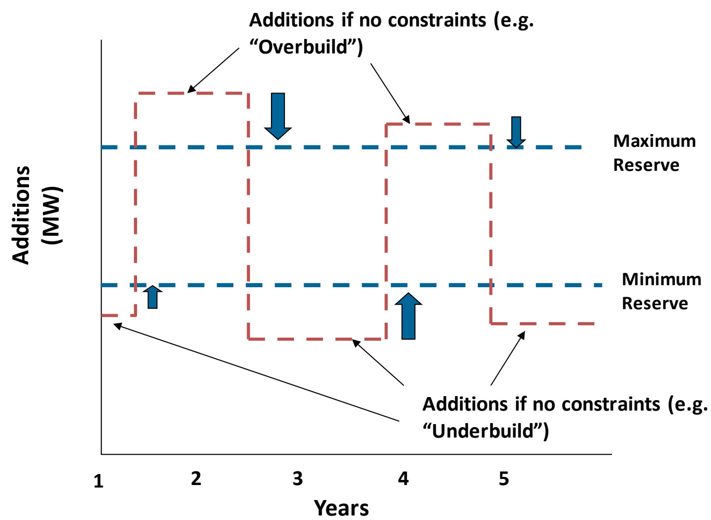
The capacity addition decision is an iterative process to gather intelligence from the markets before the decision is finalized. The iterative process steps are outlined below:

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.

The algorithm used by the model to calculate capacity prices does not mirror the PJM Reliability Pricing Model ("RPM"), which establishes capacity prices through an auction process. The Ventyx methodology, however, incorporates the same fundamental principles employed by the RPM such that the capacity price is established by zone; excess capacity results in lower capacity prices; and when capacity is just sufficient to satisfy the overall reliability requirement, the capacity price is adequate to make the marginal resource whole.

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 free-on-board 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 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.[13] 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.

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

[13] 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.

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.

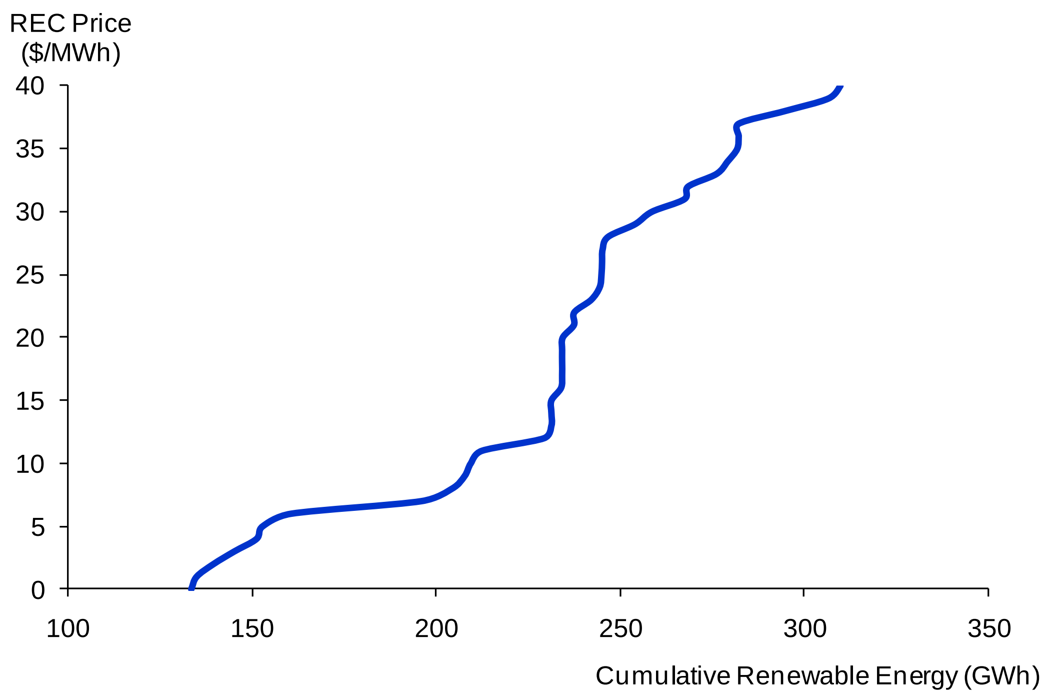
After all such additions have been made, the Module then identifies states (or the nation as a whole in the event that a federal RPS is modeled) in which the RPS is not satisfied. The Module then identifies the renewable capacity additions that: 1) together satisfy the RPS, and 2) require the lowest 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 8,760-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.

Generator Outages. 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 capacity, 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.

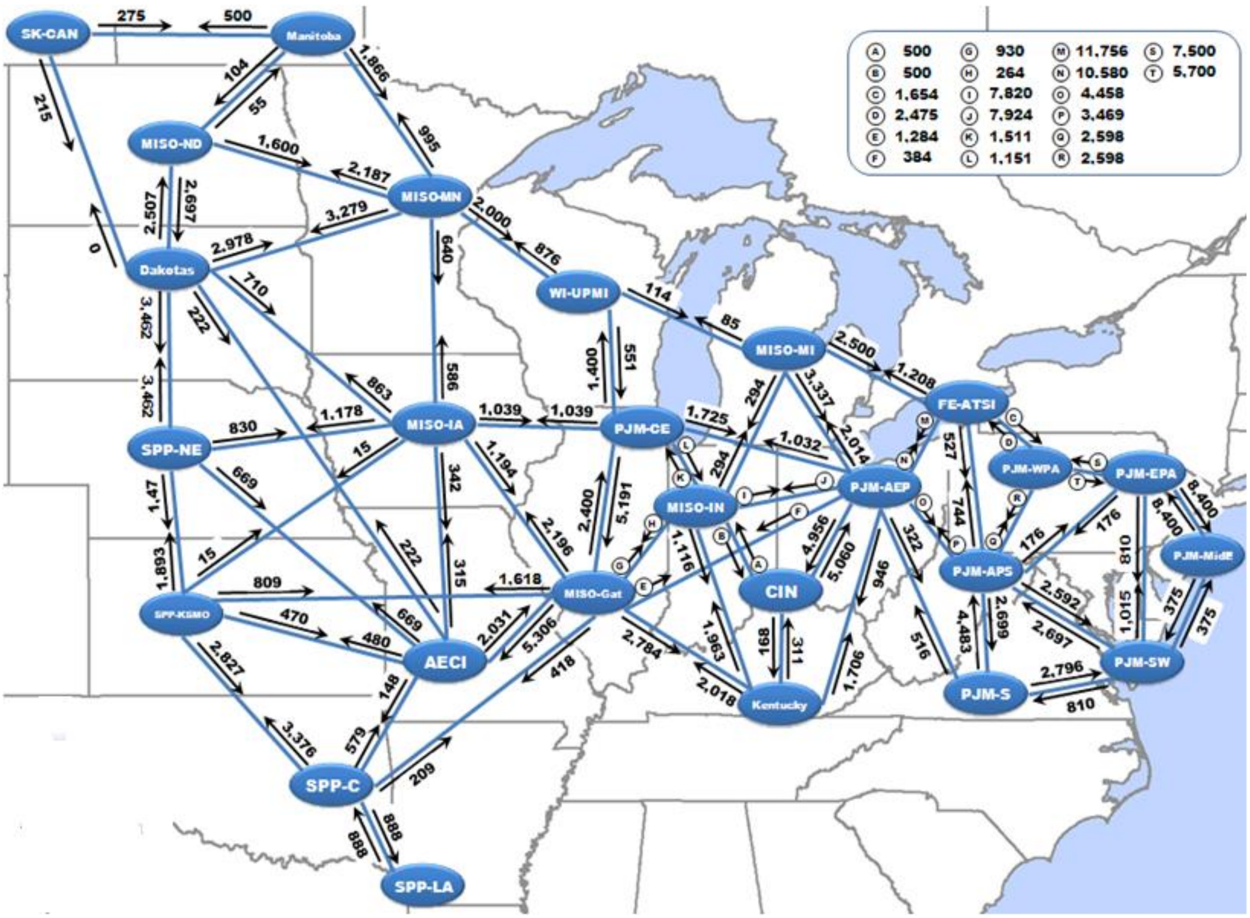
Each category contains key assumptions, which are presented and discussed below.

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 Potomac Electric Power Company ("Pepco") and

Baltimore Gas and Electric ("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



Note: The numbers between bubbles represent the directional MW transmission transfer capacity between the zones.

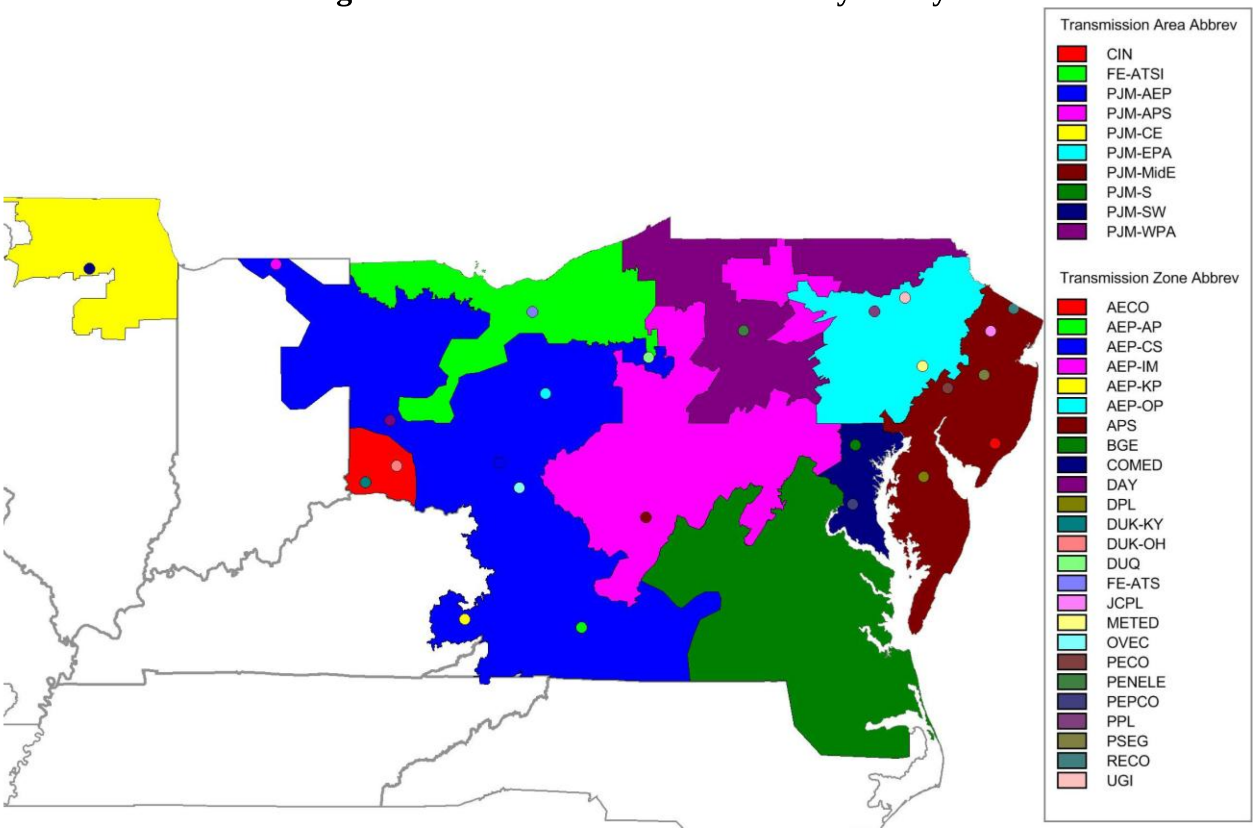
Table 3.1, below, describes the geographic areas associated with the market bubbles shown in Figure 3.1, above. Note that certain states, including Maryland, are listed within more than one market area. In those cases, different portions of the state are contained within different market areas. The market 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 and completion was scheduled for June 2011.[14] 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.

[14] TrAIL was subsequently put in-service in May 2011.

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.[15] The energy and demand reductions associated with utility EmPOWER Maryland programs 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.

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.

Under EmPOWER Maryland, the utilities were responsible for achieving a 10 percent reduction in per capita energy consumption (relative to 2007 levels) with an additional 5 percent to come from government programs and updated codes and standards. The LTER Reference Case assumption is that government programs/codes and standards will achieve the same level of success as the utility programs resulting in a total energy consumption reduction in 2015 of 4 million MWh.

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

The Maryland Public Service Commissions subsequently adjusted the utility forecast target achievements based on data from Maryland utility filings in early 2011. Based upon an updated 2015 goal[16], the utilities are projected to achieve 130 percent, or 2,744 MW, of the demand reduction goal and 73 percent, or 3.999 million MWh of the annualized energy savings goal by 2015. The projection is based upon verified data for 2009 through 2010, utility reported data for the first two quarters of 2011 and utility forecasts for the second half of 2011 through 2015.

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.[17] 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;[18]
- 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;
- 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.

[16] In 2011, the Maryland Public Service Commission adjusted the goals as calculated in 2008 due to changes in population growth in the five service territories.
[17] See Appendix D for a detailed discussion of the PEV adjustment.
[18] Balducci, P.J., Plug-in Hybrid Electric Vehicles Market Penetration Scenarios, DOE Pacific Northwest National Laboratory, September 2008.

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. Note that demand response is treated as a callable resource in the Ventyx model and therefore MW reductions due to demand response are not reflected in the values in Table 3.5.

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 plots the base, high, and low natural gas price projections for the Henry Hub, which is the most liquid natural gas hub in the U.S.[19] 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.

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

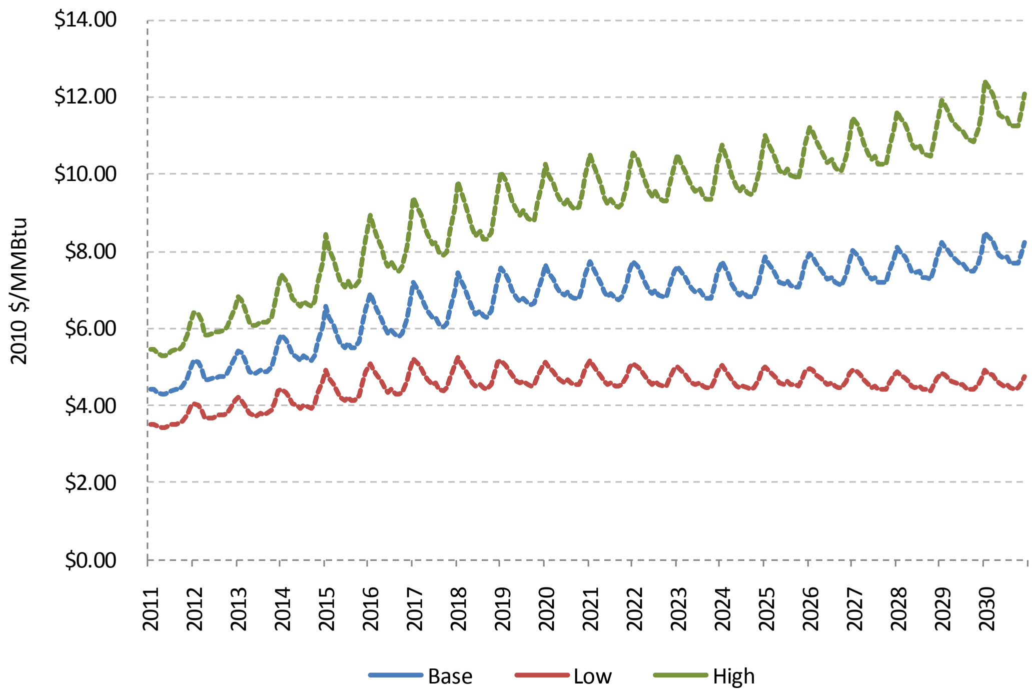
Year	Low		Base		High	
	Average	Max	Average	Max	Average	Max
2011	3.56	3.97	4.46	4.98	5.50	6.15
2012	3.84	4.12	4.89	5.24	6.09	6.53
2013	3.94	4.36	5.09	5.63	6.41	7.09
2014	4.16	4.61	5.46	6.05	6.93	7.69
2015	4.43	4.93	5.90	6.57	7.57	8.42
2016	4.59	5.09	6.22	6.90	8.05	8.93
2017	4.74	5.21	6.53	7.18	8.53	9.37
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

[19] 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 the Energy Information Administration's *Annual Energy Outlook*, is based in part on Henry Hub prices. The Henry Hub is physically located in Louisiana.

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



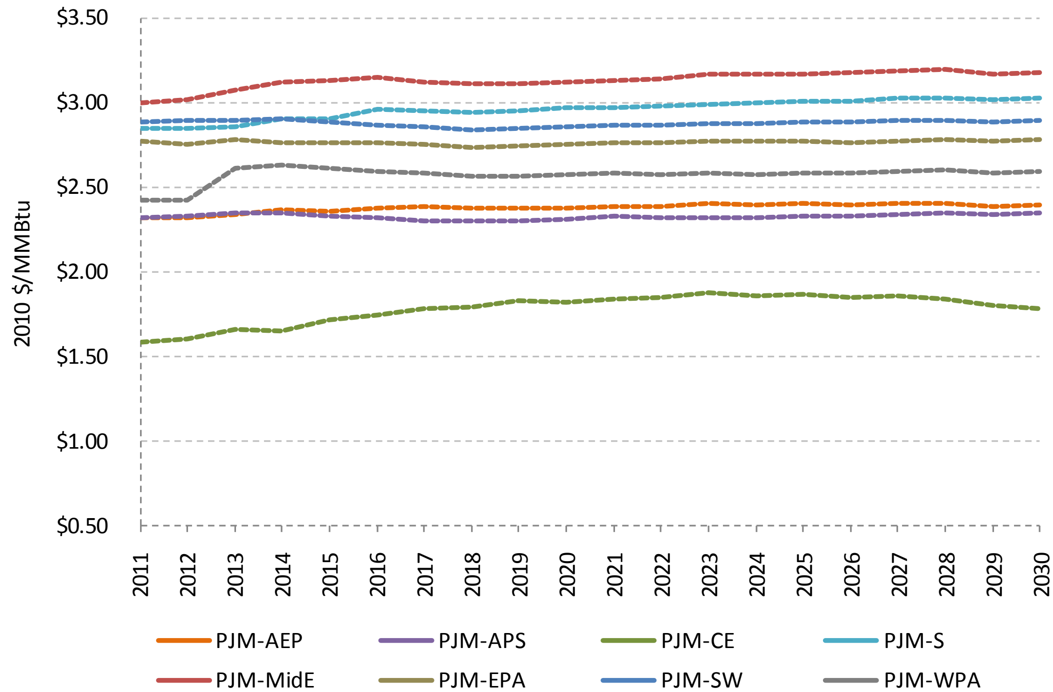
Source: Ventyx's Fall 2010 Reference Case.

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 ("EIA") 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 judged to be too similar to the LTER Reference Case to adequately capture the range of uncertainty associated with future gas prices. The forecasted natural 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.

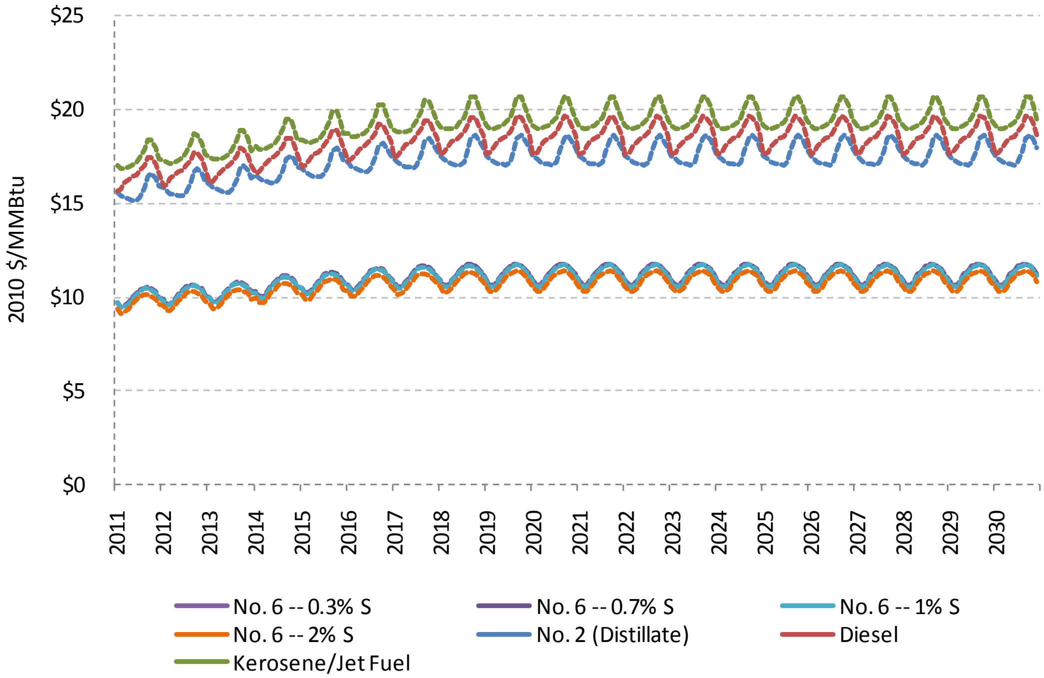
Table 3.7 Average Delivered Coal Price Forecast (2010 $/mmBtu)

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, fixed O&M, and fuel costs associated with new generation technologies and Table 3.11 contains the operational assumptions. The financial parameters needed to guide investment decisions are presented in Table 3.12, which follows.

Table 3.10 Cost Assumptions of New Generation Over the Forecast Period

Unit Type		Fixed O&M (2010 $/kW-yr)	Variable O&M (2010 $/MWh)	Fuel Costs (2010 $/MWh)	Overnight Construction Cost (2010 $/kW)
Pulverized Coal Steam Turbine	PC	$26.95	$4.00	$21.66 - $22.67	$2,660
Combustion Gas Turbine	GT	$12.60	$3.75	$46.83 - $84.11	$660
Aero derivative Gas Turbine	AD	$10.95	$3.30	$40.14 - $72.09	$1,020
Combined Cycle Natural Gas	CCNG	$13.00	$2.15	$30.33 - $54.47	$970
Integrated Coal Gasification Combined Cycle	IG	$47.30	$4.65	$20.91 - $21.88	$3,360
Nuclear	NU	$70.55	$0.55	$6.76 - $8.42	$5,870
Pulverized Coal Steam Turbine with Carbon Capture and Sequestration	PC-CCS	$32.15	$6.15	$28.21 - $29.53	$5,089
Combined Cycle Natural Gas with Carbon Capture and Sequestration	CCNG-CCS	$22.10	$3.15	$39.69 - $71.29	$2,134
Integrated Coal Gasification CCNG with Carbon Capture and Sequestration	IG-CCS	$56.40	$7.10	$27.20 - $28.47	$5,649
Geothermal Steam Turbine	GE	$169.85	$0.00	$0.00	$1,900
Landfill Gas	LG	$119.72	$0.01	$0.00	$2,550
Biomass	BM	$70.23	$7.21	$20.77 - $26.28	$3,300
Photovoltaic	PV	$12.55	$0.00	$0.00	$5,000[1]
Wind Turbine - On Shore (2010)	WT	$29.55	$0.00	$0.00	$2,200[2]
Wind Turbine - On-Shore (2011-2030)		$29.55	$0.00	$0.00	$1,800[3]
Wind Turbine - Off-Shore		$73.88	$0.00	$0.00	$4,260[4]

Source: Unless otherwise noted, information regarding the characteristics of prototype units is derived from engineering analysis conducted by Ventyx and PPRP.

[1] Declines linearly to $4,000/kW in 2030. Assumptions regarding capital costs for solar photovoltaic are based on discussions and interviews with industry experts.

[2] Ryan Wiser and Mark Bolinger. *2009 Wind Technologies Market Report*. U.S. Department of Energy, August 2010. http://eetd.lbl.gov/ea/emp/reports/lbnl-3716e.pdf. Based on a sample of on-shore wind projects in the region, it is assumed that the capital costs for on-shore wind projects in the mid-Atlantic are slightly higher than elsewhere in the country.

[3] Based on recent economic factors and market conditions, it is assumed that there will be an 18 percent decline in 2011 to a capital cost level of $1,800 per kW for 2011. It is also assumed that the 2011 capital cost level will remain constant in real dollar terms through the terminal year of the LTER study period (2030).

[4] Walter Musial and Bonnie Ram. *Large-Scale Offshore Wind Power in the United States.* National Renewable Energy Laboratory, September 2010. http://www.nrel.gov/docs/fy10osti/49229.pdf.

Table 3.11 Operational Assumptions of New Generation Over the Forecast Period

Unit Type		Summer Capacity (MW)	Capacity Factor	Full-Load Heat Rate HHV (Btu/kWh)	Forced Outage Rate (%)	Maintenance Outage Rate (MOR) (%)
Pulverized Coal Steam Turbine	PC	800		8,600	6.0%	6.5%
Combustion Gas Turbine	GT	160		10,500	3.6%	4.1%
Aero derivative Gas Turbine	AD	90		9,000	3.6%	4.1%
Combined Cycle Natural Gas	CCNG	450		6,800	5.5%	4.1%
Integrated Coal Gasification Combined Cycle	IG	600		8,300	6.0%	6.5%
Nuclear	NU	1,000		10,400	3.8%	6.1%
Pulverized Coal Steam Turbine with Carbon Capture and Sequestration	PC-CCS	540		11,200	7.0%	7.5%
Combined Cycle Natural Gas with Carbon Capture and Sequestration	CCNG-CCS	310		8,900	6.5%	5.0%
Integrated Coal Gasification CCNG with Carbon Capture and Sequestration	IG-CCS	410		10,800	7.0%	7.5%
Geothermal Steam Turbine	GE	10		10,000	20.0%	0.0%
Landfill Gas	LG	10		10,000	30.0%	0.0%
Biomass	BM	10		10,000	30.0%	0.0%
Photovoltaic	PV	10	15%		0.0%	0.0%
Wind Turbine - On Shore (2010)	WT	10	30%		0.0%	0.0%
Wind Turbine - On-Shore (2011-2030)			30%			
Wind Turbine - Off-Shore			40%			

Source: Ventyx, PPRP

Table 3.12 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 3.11, 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 3.11. The majority of the data shown in Table 3.10 and Table 3.11is from Ventyx, although the data for renewable energy sources were developed by PPRP and are 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 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"), which replaced CATR. CSAPR was included in the EPA Regulations scenarios.)

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 ("NSPS") 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 3.13, below, summarizes the percentage renewable requirements of Maryland's RPS.

Table 3.13 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 3.14, 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 3.14 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 2010. Increases to $40/MWh for 2011 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, 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 offsets, 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 3.15 shows the unadjusted and adjusted RGGI budget.

Table 3.15 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 Maryland Greenhouse Gas Reduction Act

During the 2009 legislative session, the Maryland Legislature passed the Greenhouse Gas Emissions Reduction Act of 2009 ("GGRA"), which requires the State to reduce greenhouse gas emissions by 25 percent below 2006 levels by 2020. The GGRA directs the State to develop and adopt a specific plan and regulations, and implement specific programs to reduce greenhouse gas emissions. The draft plan is due to be completed in December 2011, with the final plan set to be adopted in December 2012. The GGRA is a multi-sector emissions reductions bill, which addresses the main greenhouse gases (CO_2, CH_4, and N_2O), and requires greenhouse gas emissions reductions in all sectors for a total Statewide reduction of 25 percent by 2020. The GGRA states that measures regarding emissions reductions related to energy supplies do not "decrease the likelihood of reliable and affordable electrical service," and consideration needs to be given to whether the measures will result in increased electricity costs to consumers.

The GGRA also requires the Maryland Department of the Environment ("MDE") to prepare and publish an updated inventory of Statewide greenhouse gas emissions for calendar year 2006 and develop a projected "business-as-usual" inventory for calendar year 2020. These were completed in June 2011. The inventory includes greenhouse gas emissions estimates for all sectors, including power generation and power consumption-based emissions of greenhouse gases (CO_2, CH_4, and N_2O). According to the MDE inventory, in 2006, Maryland's electricity consumption-based greenhouse gas emissions were about 42.2 million tons of carbon dioxide equivalent ($MMtCO_{2e}$), making up about 39 percent of total gross State greenhouse gas emissions.[20] The inventory includes all power plants in Maryland (both RGGI and non-RGGI generators) and small-scale and behind-the-meter generators, and utilizes the general PJM generation mix emissions to estimate emissions associated with electricity imports.

The GGRA implementation plan will depend on a menu of mechanisms to reduce greenhouse gas emissions. These mechanisms are anticipated to include, among other things, the Maryland Renewable Portfolio Standard, RGGI, and EmPOWER Maryland. All three of these

[20] The other sectors addressed in the GGRA emissions inventory are: residential, commercial, and industrial fuel use; transportation; fossil fuel industry; industrial processes; agriculture; and waste management.

existing programs are incorporated into the LTER Reference Case and the alternative scenarios.[21] Other programs may be recommended for adoption to help achieve the 25 percent greenhouse gas reduction specified in the GGRA, but these additional programs (or modifications to existing programs) have not yet been recommended and adopted. As these programs become specified and are put into an energy plan, they will be incorporated into subsequent LTERs.

3.5.5 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 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 and 2, Chalk Point 1, and Wagner 3.
- Morgantown had NO_x emissions rates lower than the DOE report, so the actual rates were applied.

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[21] Some of the alternative scenarios are based on expansion of one or more of these programs. For example, the High Renewables scenarios are predicated on the assumption of an augmented Maryland RPS that would require retail suppliers to provide 30 percent of power deliveries as renewable energy by 2030 in contrast to the existing 20 percent requirement by 2022.

- 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 3.16 lists the emissions rates applied to the Maryland HAA plants.

Table 3.16 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 a set of assumptions that incorporates existing legislation regarding renewable energy development, the existing PJM backbone transmission system,[22] existing power plants (including those currently under construction), and a forecast of energy and peak demand consistent with PJM's December 2010 forecast.[23] 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.

[22] 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.

[23] 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 Advanced Metering Infrastructure effects.

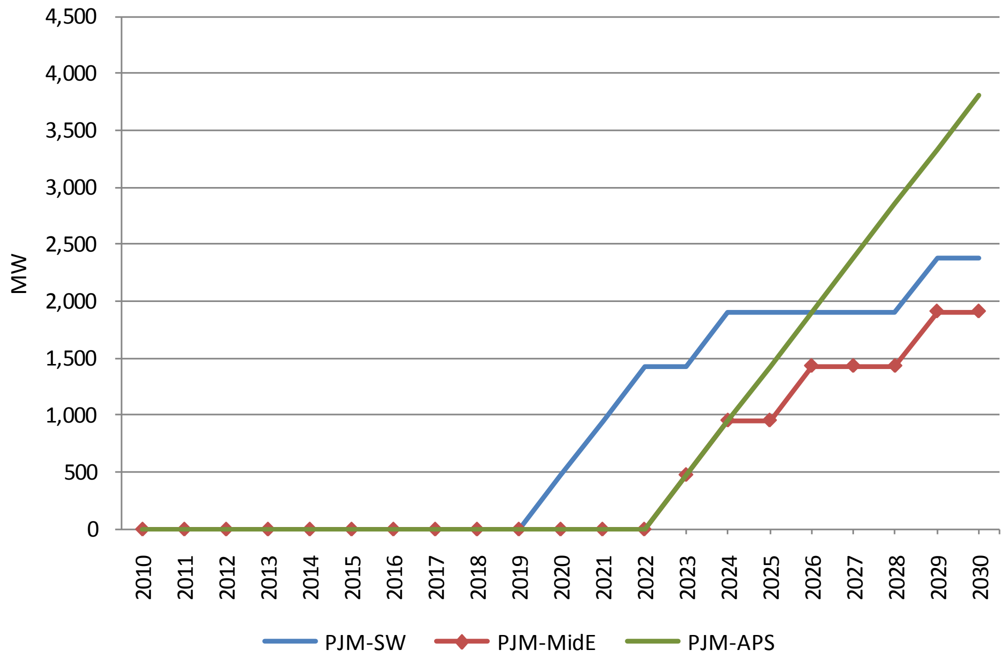
Table 4.1 LTER Reference Case Planned Capacity Additions

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 model 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.[24] This is not a modeling restriction; it is a result based on least-cost system additions.

Figure 4.1 LTER Reference Case Generic Natural Gas Capacity Additions



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 and the District of Columbia. Plants constructed in PJM-MidE and PJM-APS are assigned to the relevant zone and not to a 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 require new resources until at least 2020. Existing generating capacities combined with the import/export capacities of the existing transmission system (including TrAIL) adequately meet 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

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[24] The model adds discrete natural gas power plants. The effective capacity of each combined cycle natural gas ("CCNG") 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.

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 alternative scenarios presented 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.[25] The Ventyx model used for the LTER does not construct intermittent renewable generation to meet load requirements. To satisfy RPS requirements in the states having RPS legislation, renewable generation is added exogenously (i.e., as an input) to the model. When an RPS calls for a specific technology, such as solar energy related to Maryland's solar carve-out in its RPS, that specific technology is added. The remaining RPS compliance is met through additions of the least-cost feasible qualifying technology.

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.

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

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

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 amount 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), 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.

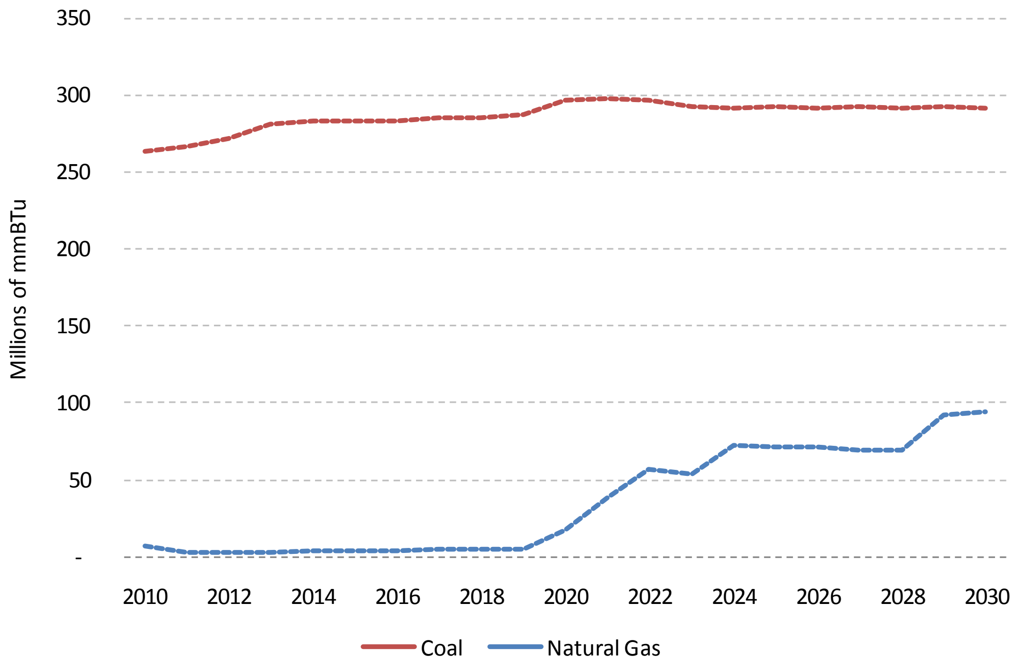
Table 4.5 LTER Reference Case Maryland Generation Shares by Fuel Type (%)

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 LTER Reference Case 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 each of the three Maryland zones are higher than the PJM average energy prices throughout the study period.[26]

[26] 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.

Table 4.6 LTER Reference Case 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 in the last few years. This price convergence is 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 LTER Reference Case PJM Real On-Peak Energy Prices

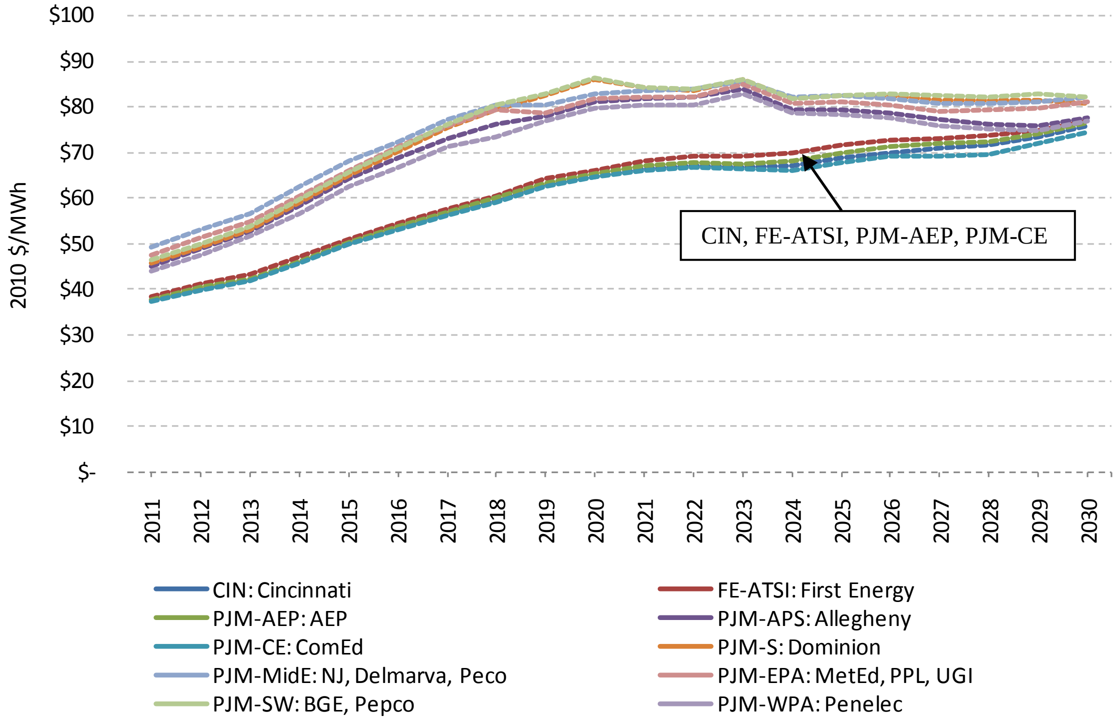


Figure 4.4 LTER Reference Case PJM Real Off-Peak Energy Prices

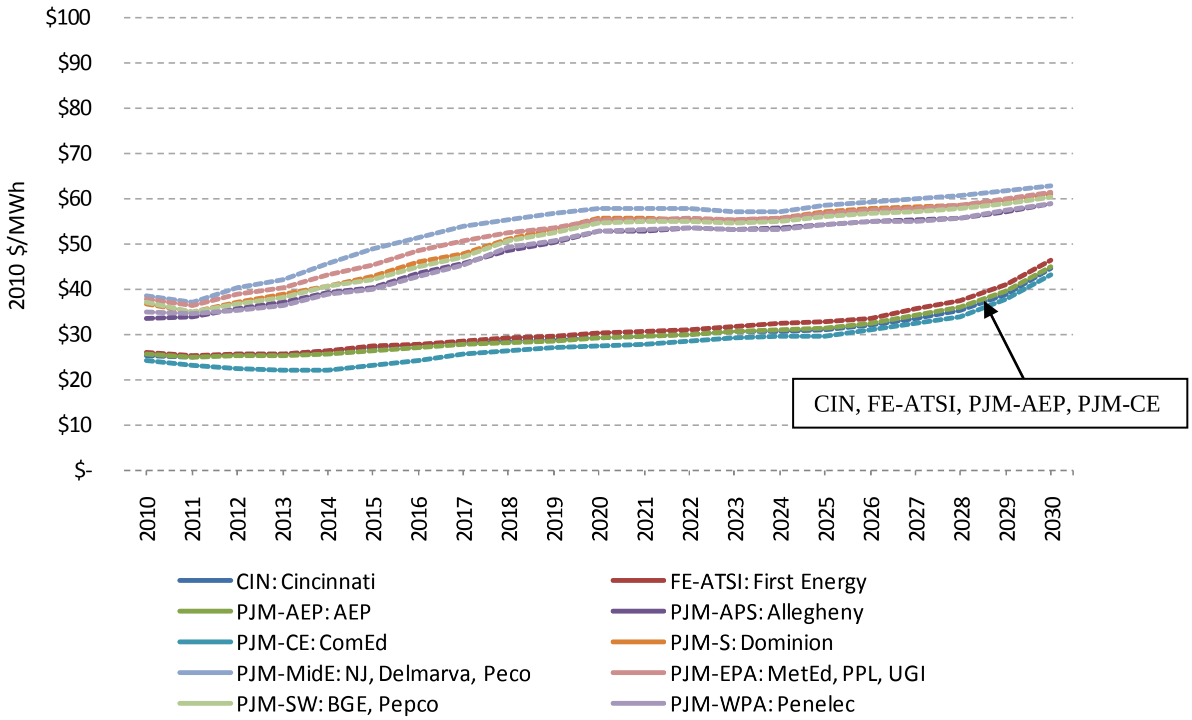
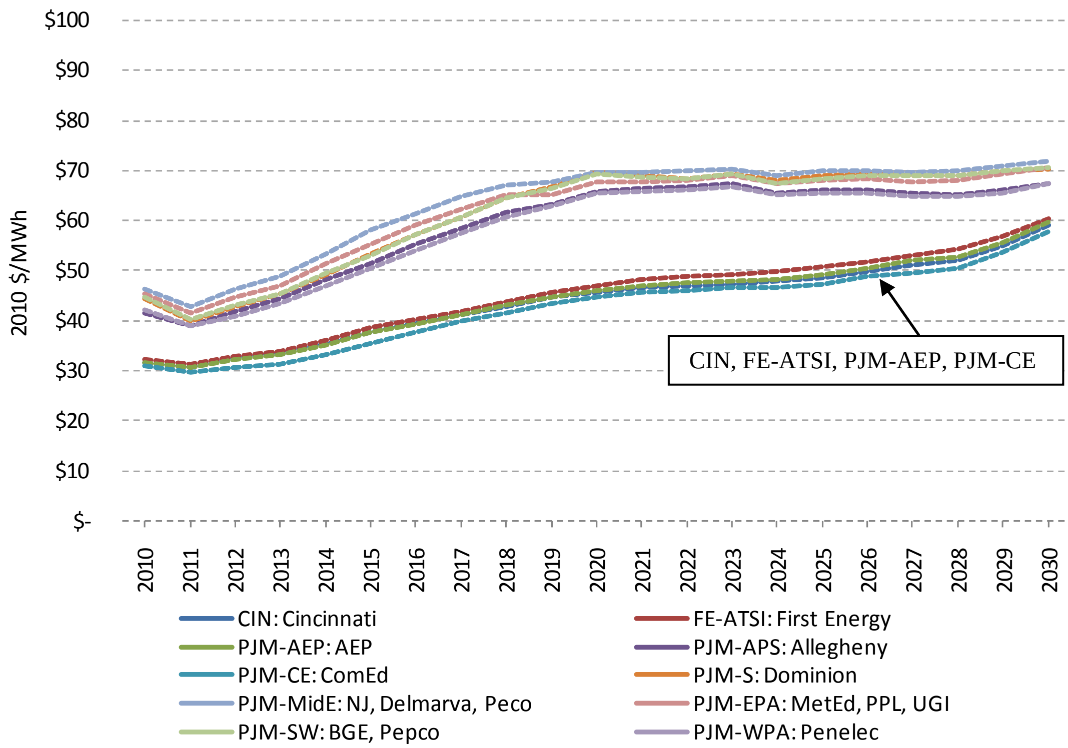


Figure 4.5 LTER Reference Case PJM Real All-Hours Energy Prices

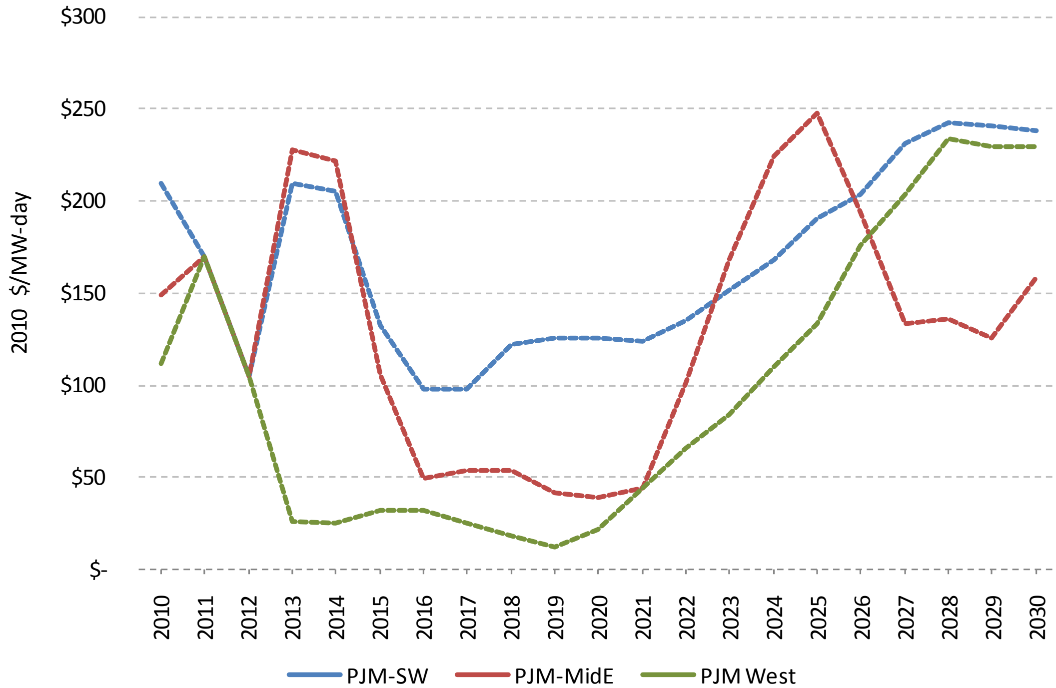


4.6 Capacity Prices

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.[27] 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.

[27] 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 lead 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 LTER Reference Case Maryland HAA Plant SO_2 Emissions

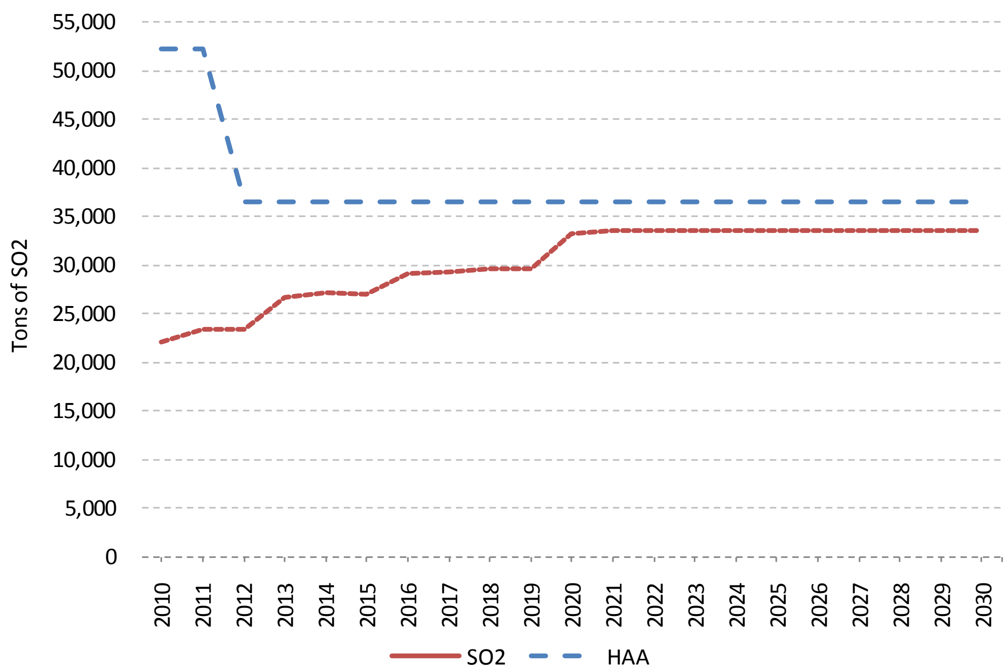


Figure 4.8 LTER Reference Case Maryland HAA Plant NO_x Emissions

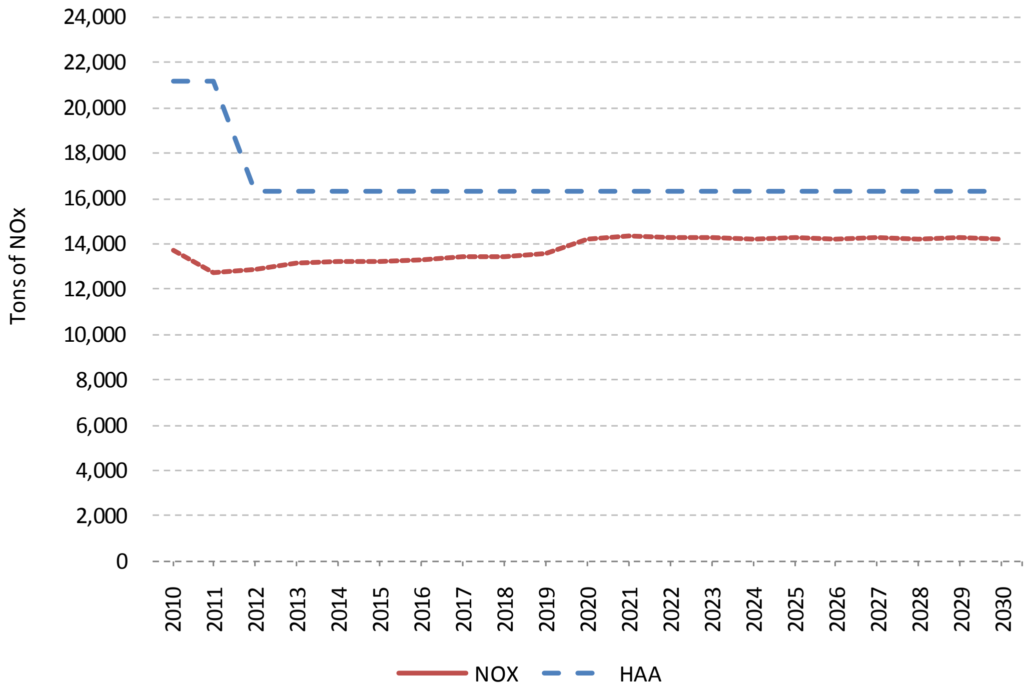
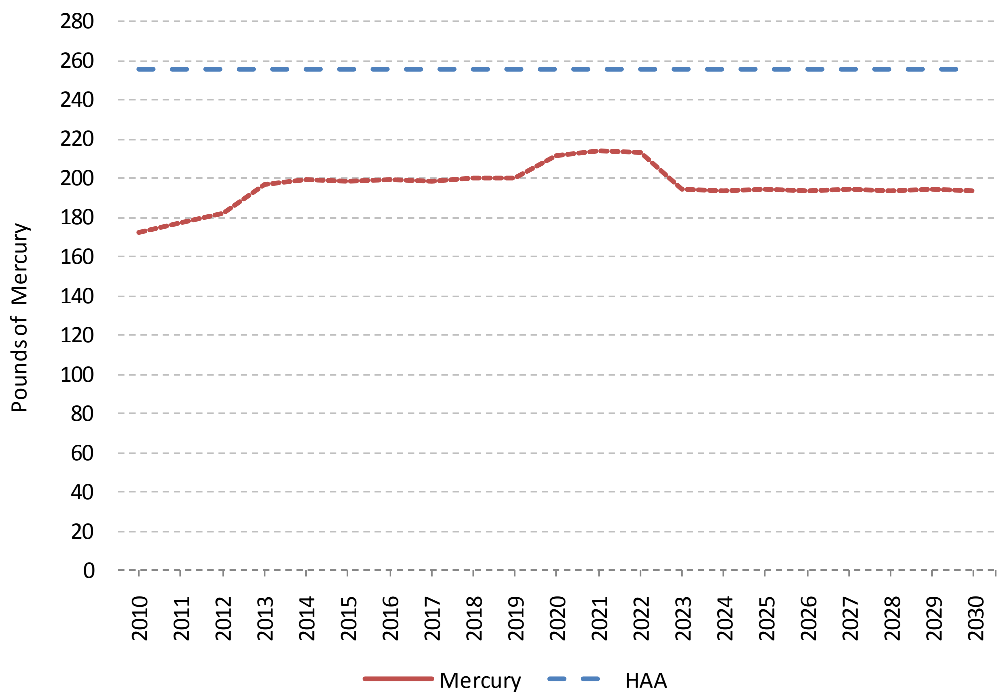


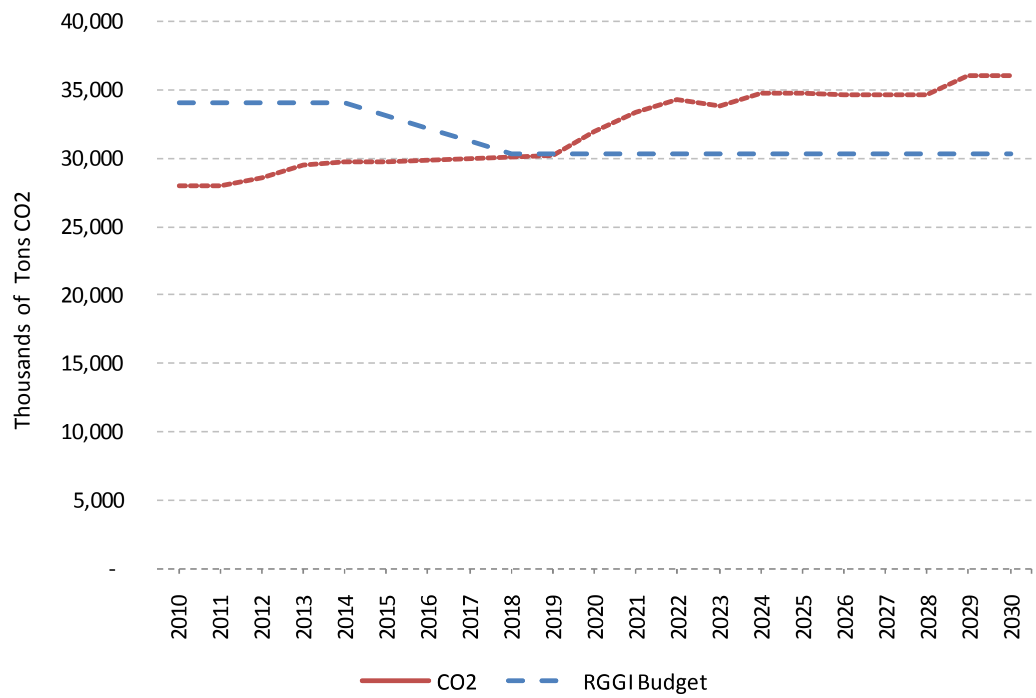
Figure 4.9 LTER Reference Case Maryland Mercury Emissions



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 LTER Reference Case Maryland Electric Generation CO_2 Emissions[28]



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.

[28] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

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, construction of new generation is not needed 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$) 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 ("RC") 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.[29] The six stand-alone/combination alternative scenarios examined are: MSD alone, MAPP alone, MSD+MAPP, CC3 alone, CC3+NCO2, and CC3/NCO2/MSD/MAPP.

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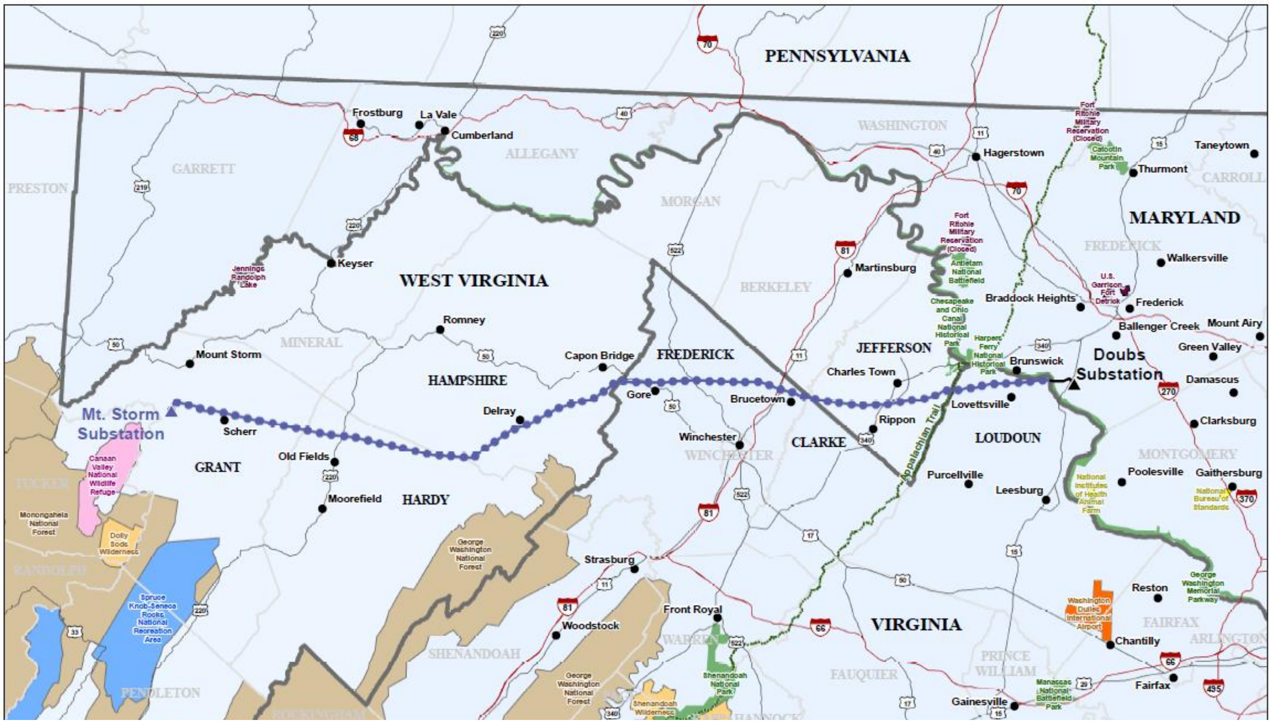
[29] Note that PJM and Pepco Holdings Inc. subsequently announced MAPP would be put off until at least 2019. http://www.atlanticcityelectric.com/welcome/news/releases/archives/2011/article.aspx?cid=1811

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

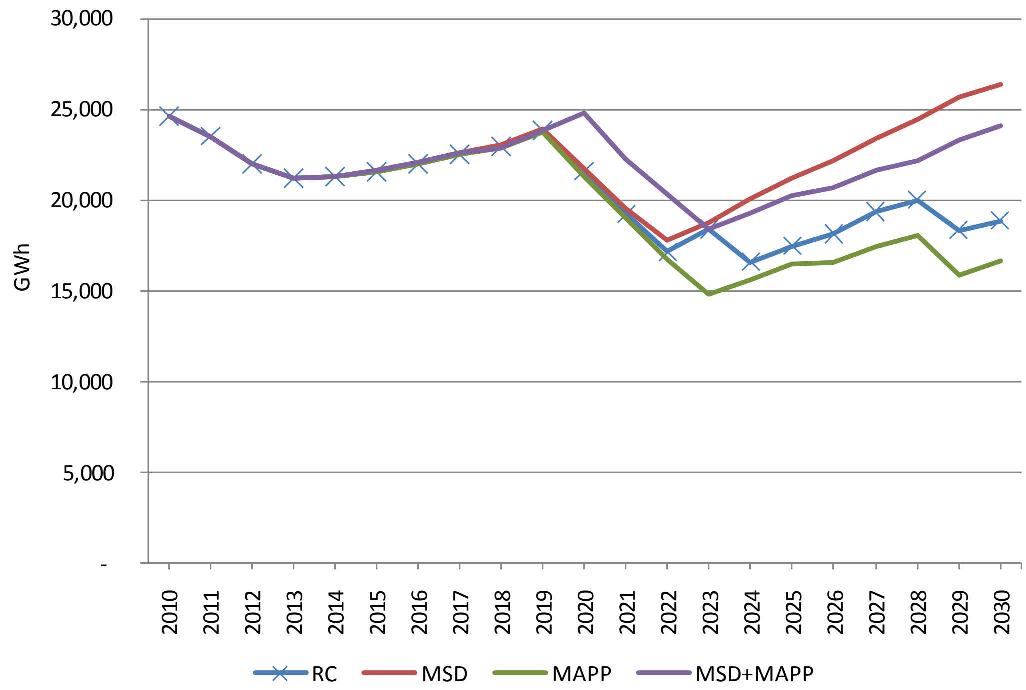
Figure 5.2 MAPP Transmission Project

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

5.2 Net Imports

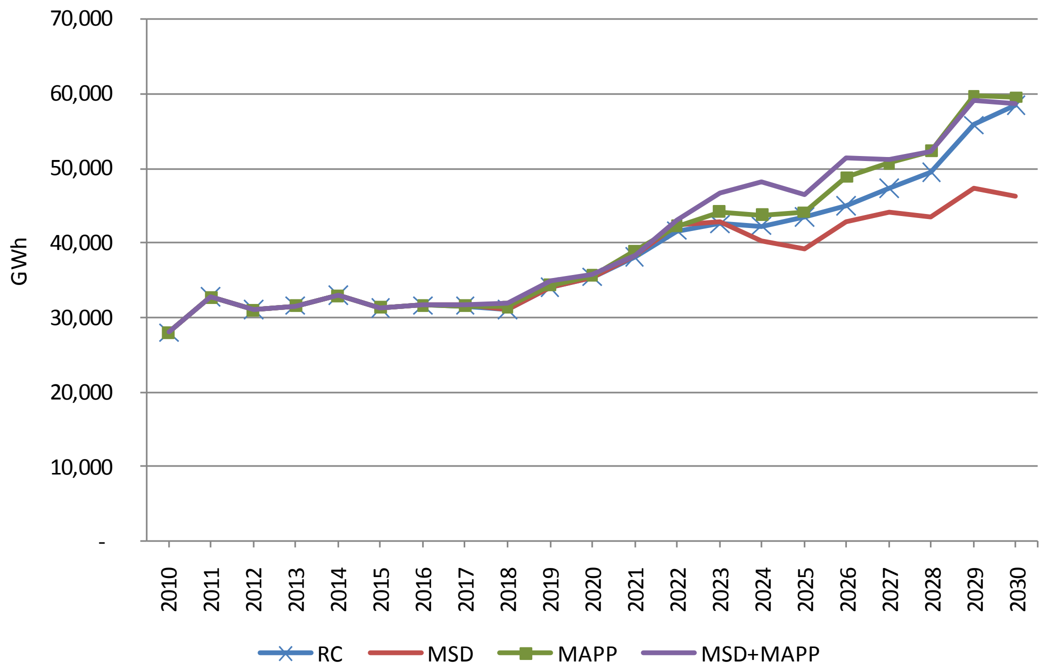
Net imports are strongly affected by both transmission improvements and carbon legislation, and, in PJM-SW, by the capacity addition represented by CC3. PJM-SW and PJM-MidE are significant importers of energy from PJM-APS and other Western PJM zones. Figure 5.3, below, shows the effect of transmission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

Figure 5.3 PJM-SW Net Imports - 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 - 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 PJM-SW (see Figure 5.5).

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 5.5 PJM-APS Net Imports - Transmission Scenarios

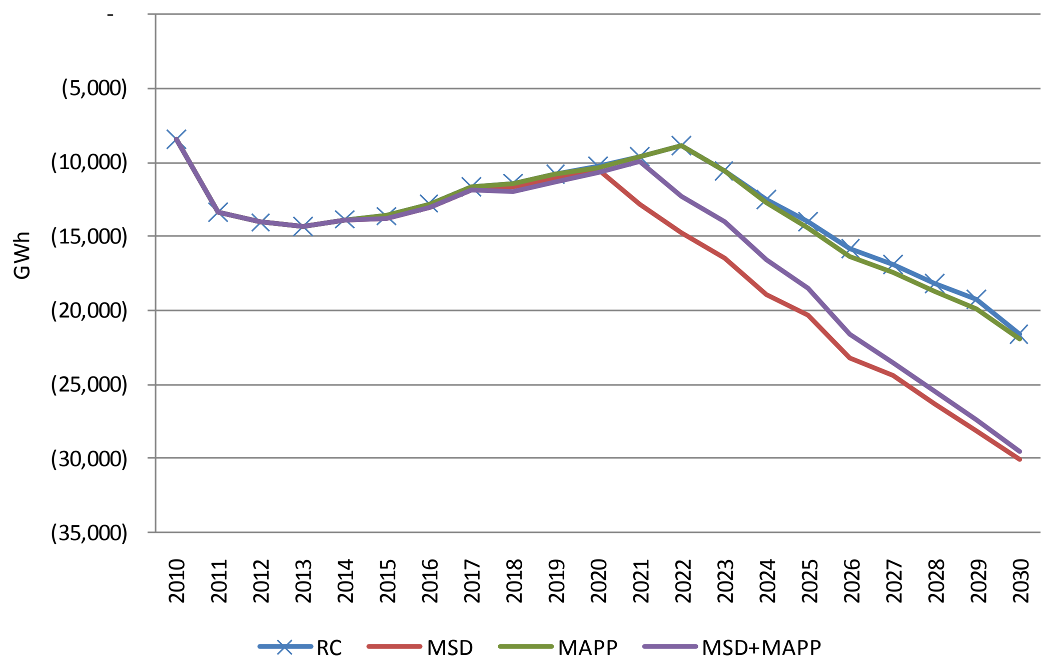
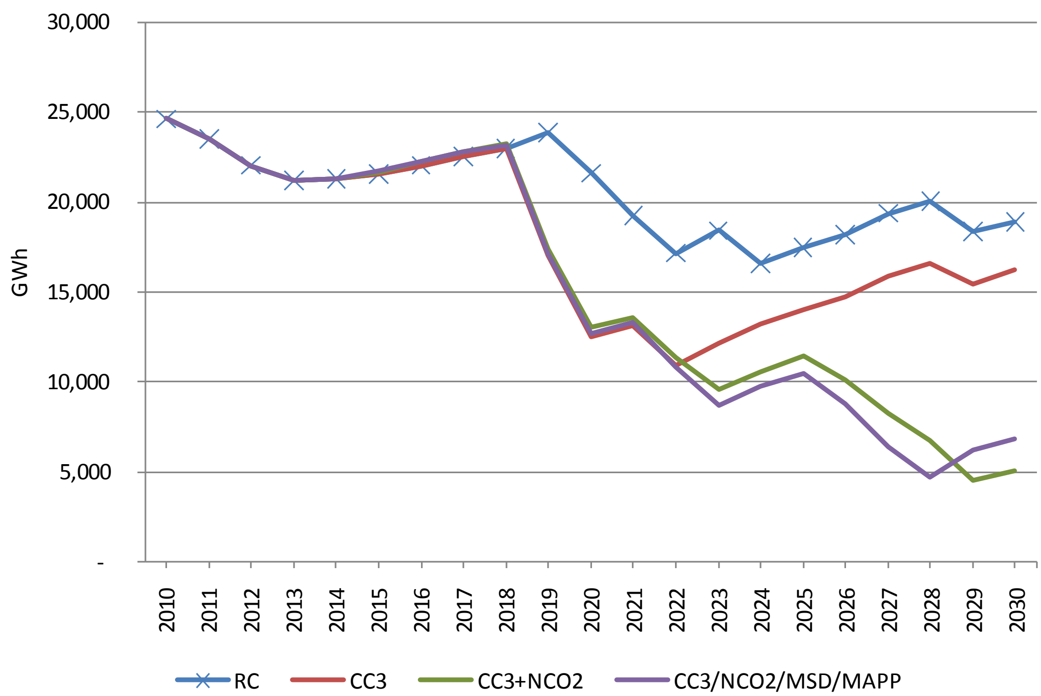


Figure 5.6 PJM-SW Net Imports - CC3 Scenarios



Under CC3 alone, PJM-SW net imports decline when Calvert Cliffs 3 comes online, 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 - CC3 Scenarios

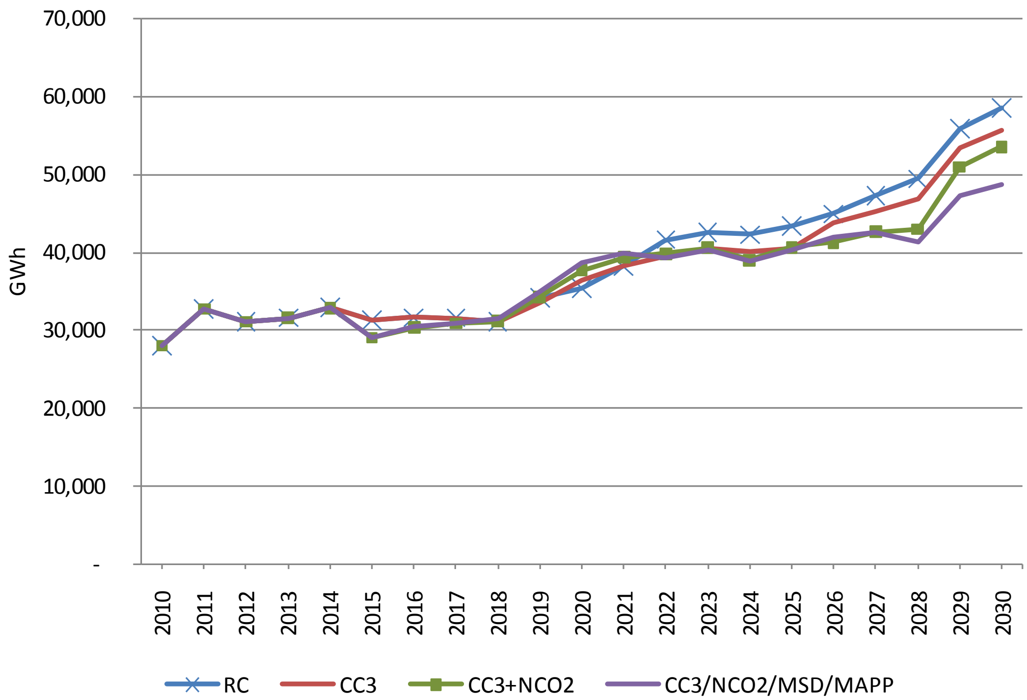
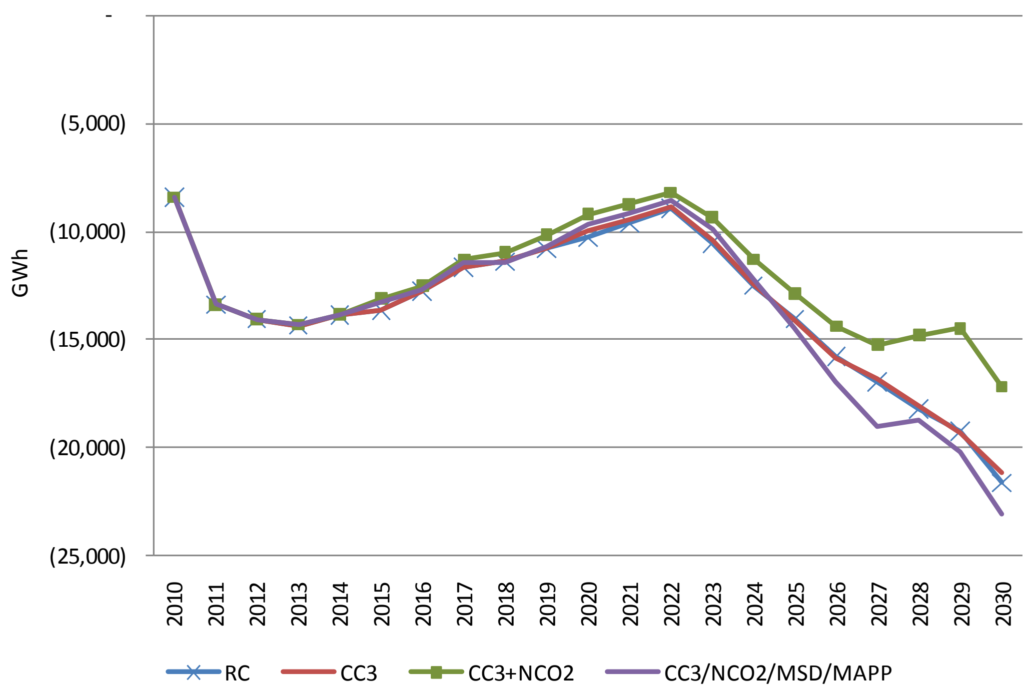


Figure 5.8 PJM-APS Net Imports - CC3 Cases



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 PJM Cumulative Retirements and Retrofit Capacity Reductions – CC3 Scnearios (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 capture and sequestration technology in the last six years of the study period when carbon prices accelerate. Plants retrofitted with carbon capture and 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.[30] These plants are also assumed to have an increase in O&M costs, which changes their position in the model's dispatch stack.[31] 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,

[30] 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.
[31] 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.

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.

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

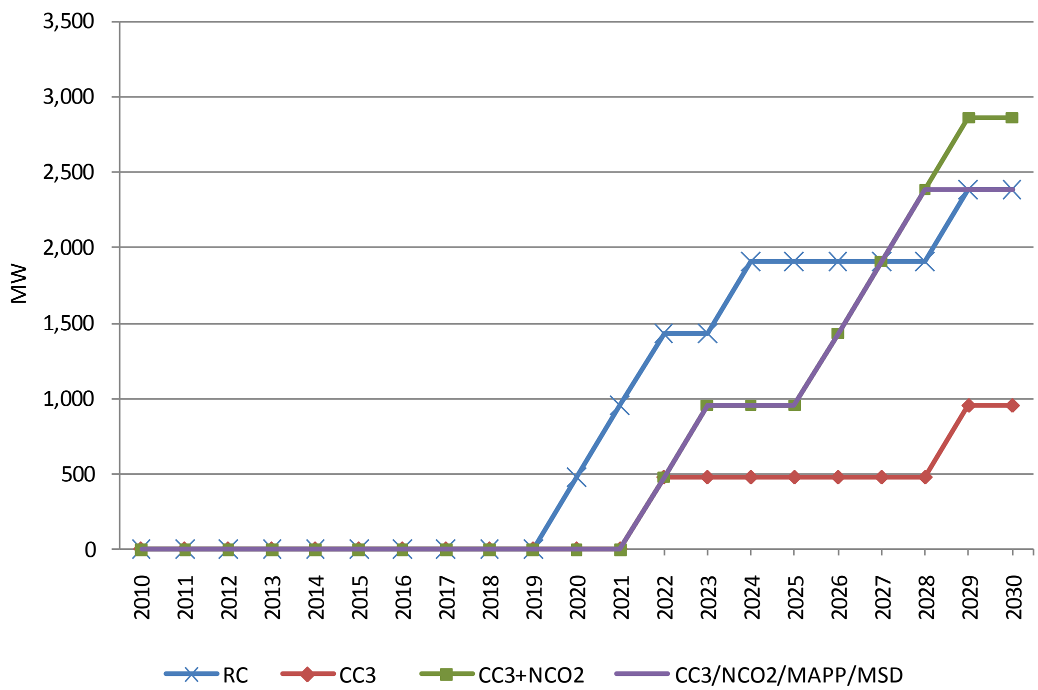
Scenario	PJM-SW	PJM-MidE	PJM-APS	PJM Total
RC	2,385	1,908	3,816	30,101
MSD	1,431	3,816	4,770	30,145
MAPP	2,385	1,908	3,816	30,101
MSD+MAPP	1,431	2,082	4,293	30,016
CC3	954	2,385	3,816	28,496
CC3+NCO2	2,862	2,385	3,816	35,273
CC3/NCO2/MSD/MAPP	2,385	4,467	3,816	35,661

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).

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.

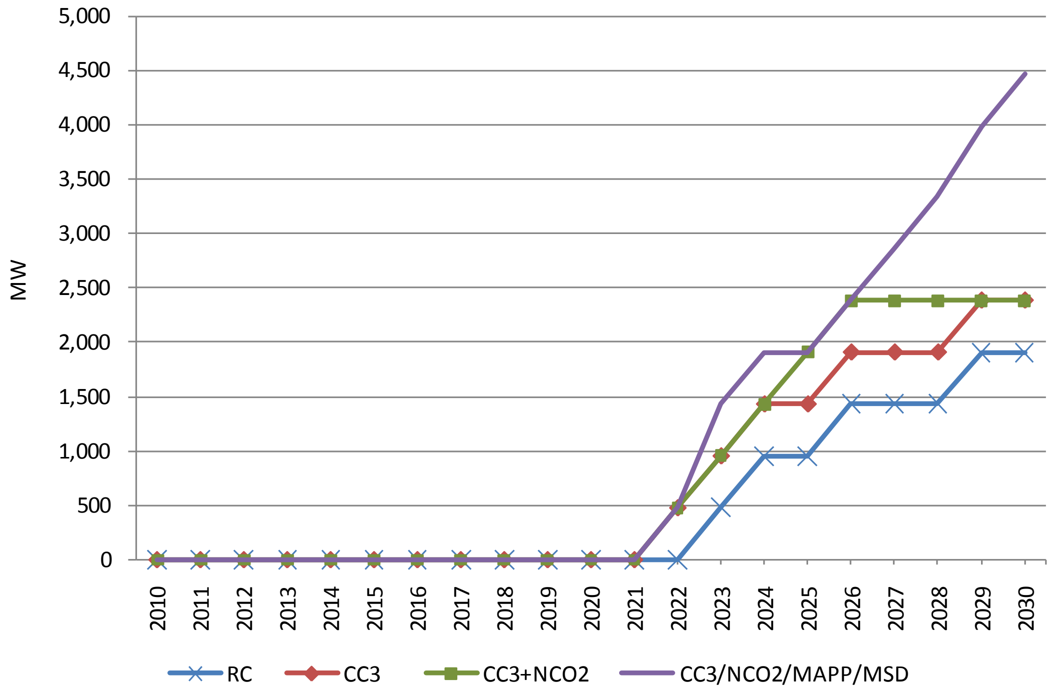
Figure 5.9 PJM-SW Natural Gas Capacity Additions – CC3 Scenarios



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 – CC3 Scenarios



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 – Infrastructure Scenarios (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

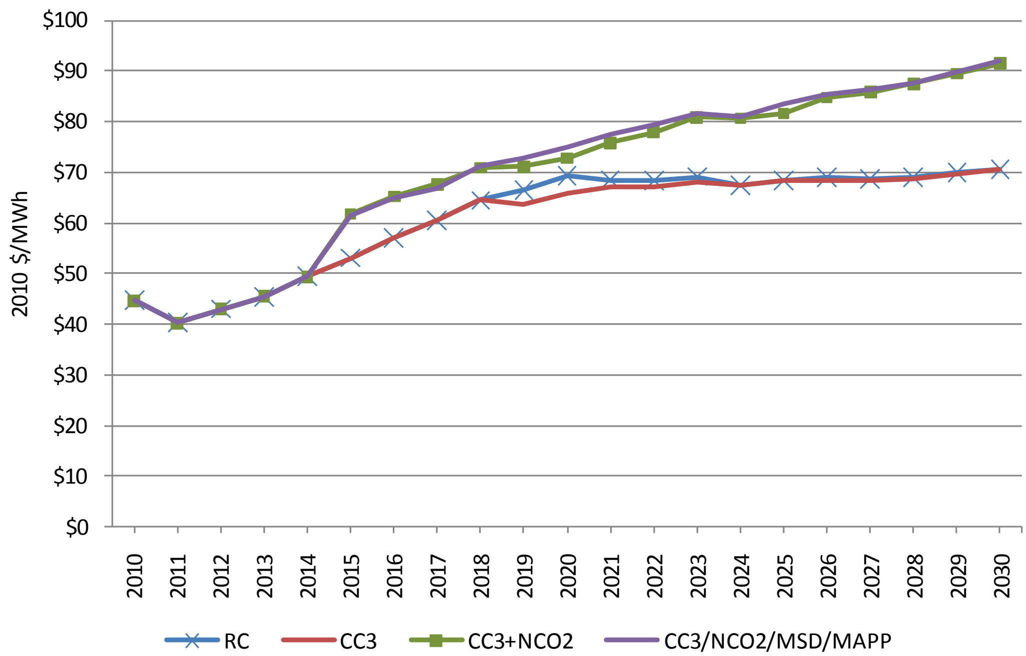
Wholesale energy prices in the three Maryland-relevant zones are only marginally affected by transmission improvements. PJM-SW energy prices are almost identical to the LTER Reference Case throughout the study period under the transmission scenarios (see Table 5.4 below). PJM-MidE and PJM-APS prices 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 - 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 – CC3 Scenarios



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

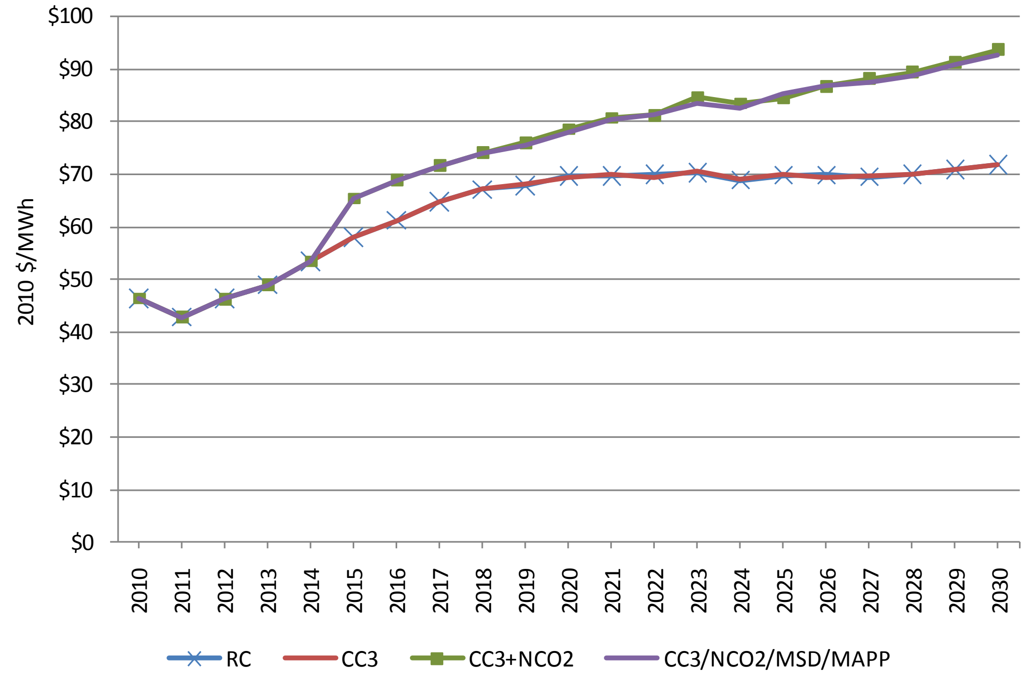
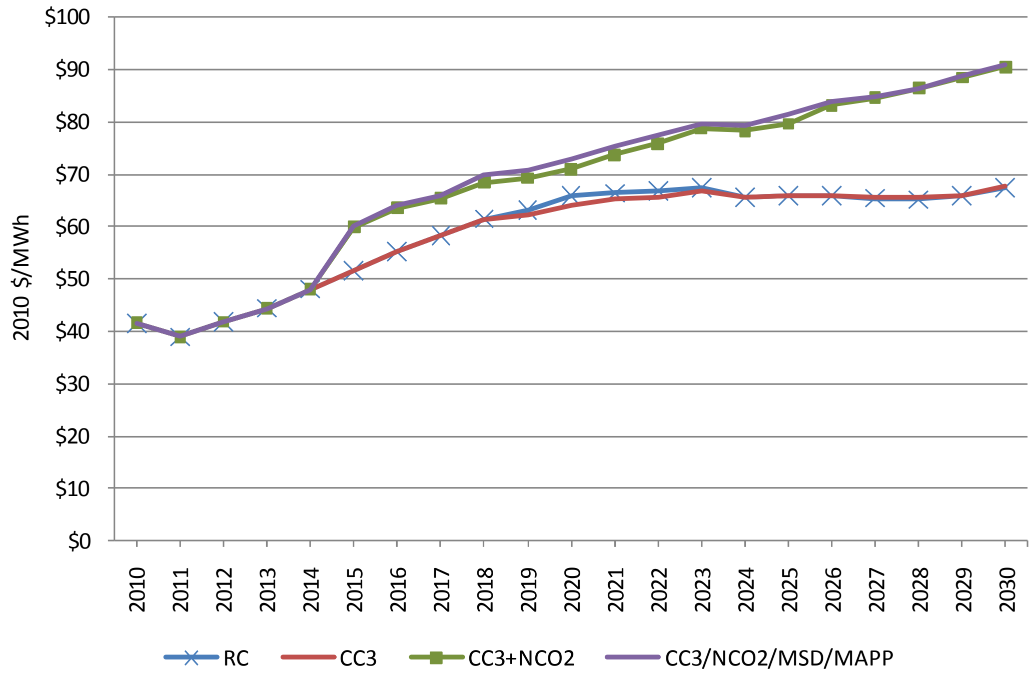


Figure 5.13 PJM-APS Real All-Hours Energy Prices - CC3 Scenarios



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 - Transmission Scenarios

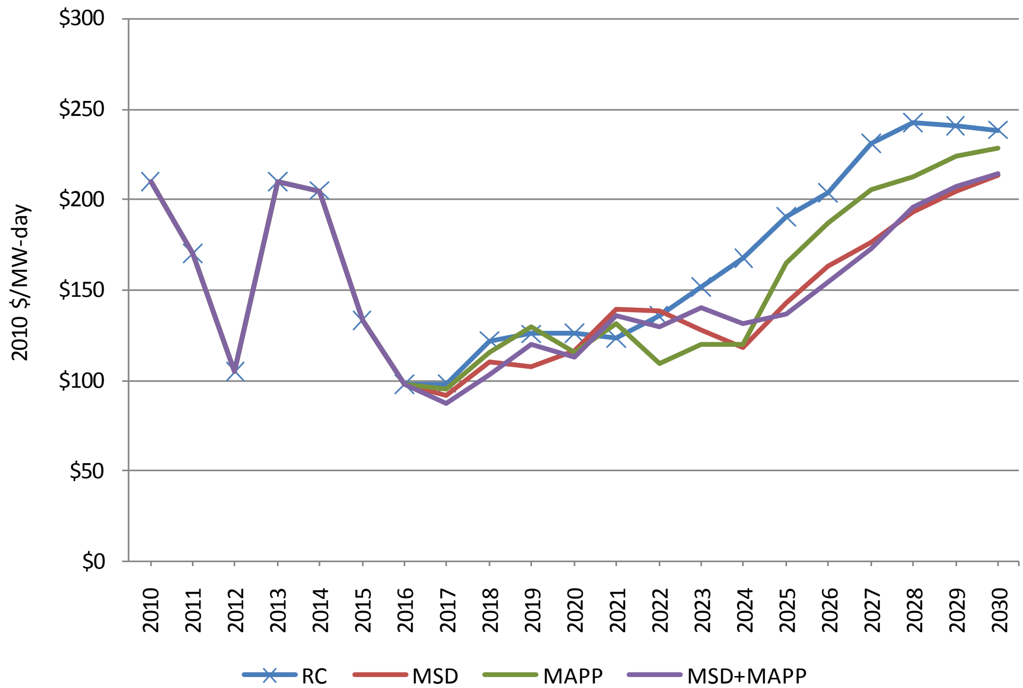


Figure 5.15 PJM-SW Capacity Prices - CC3 Scenarios

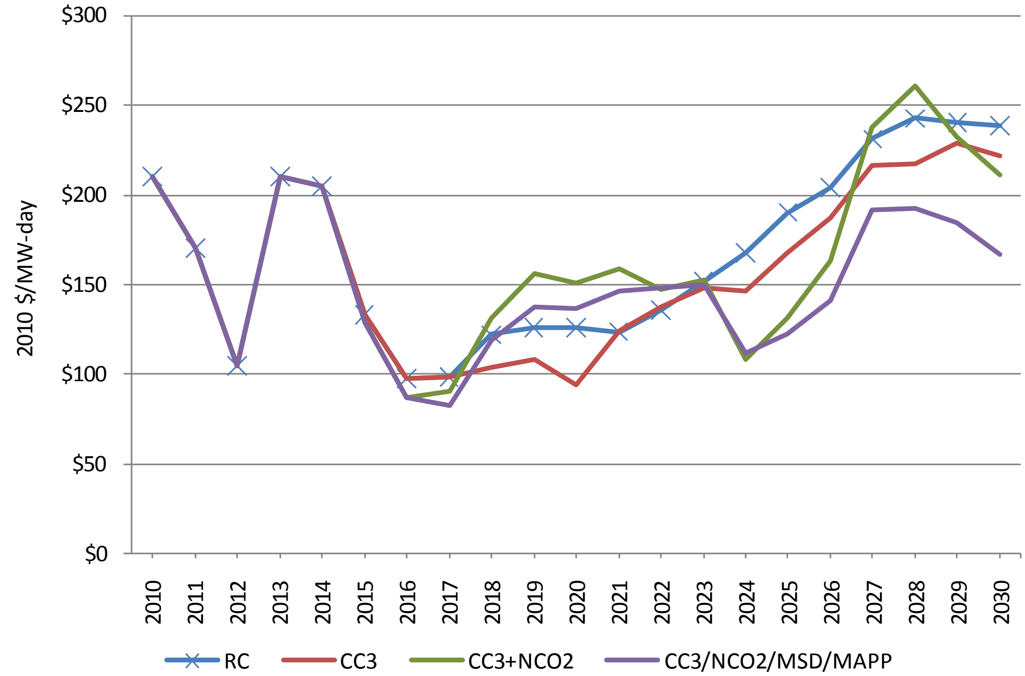


Figure 5.16 PJM-MidE Capacity Prices - Transmission Scenarios

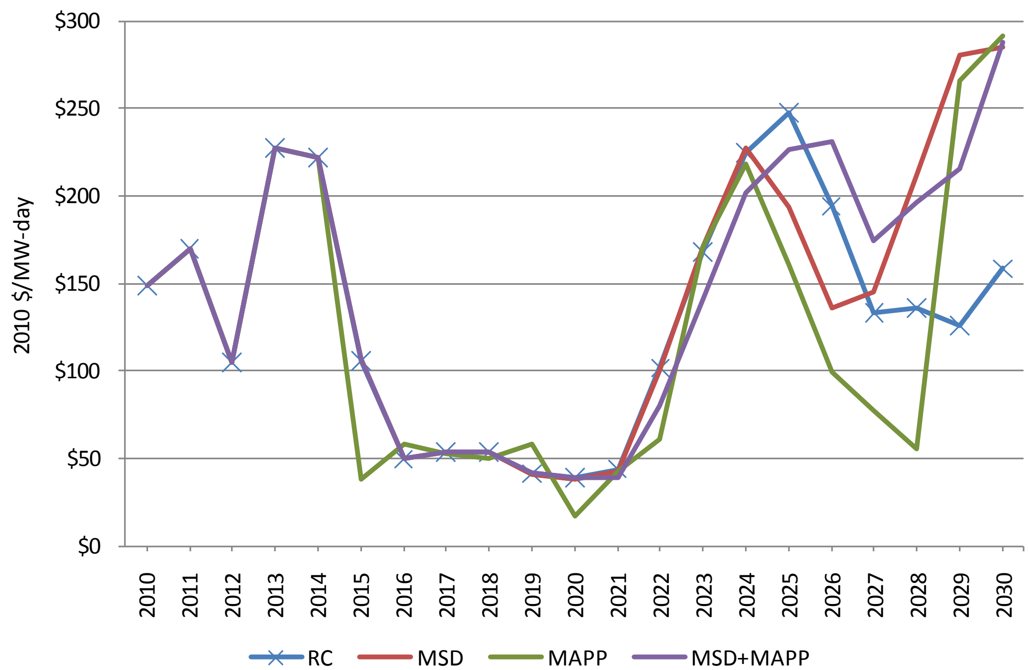
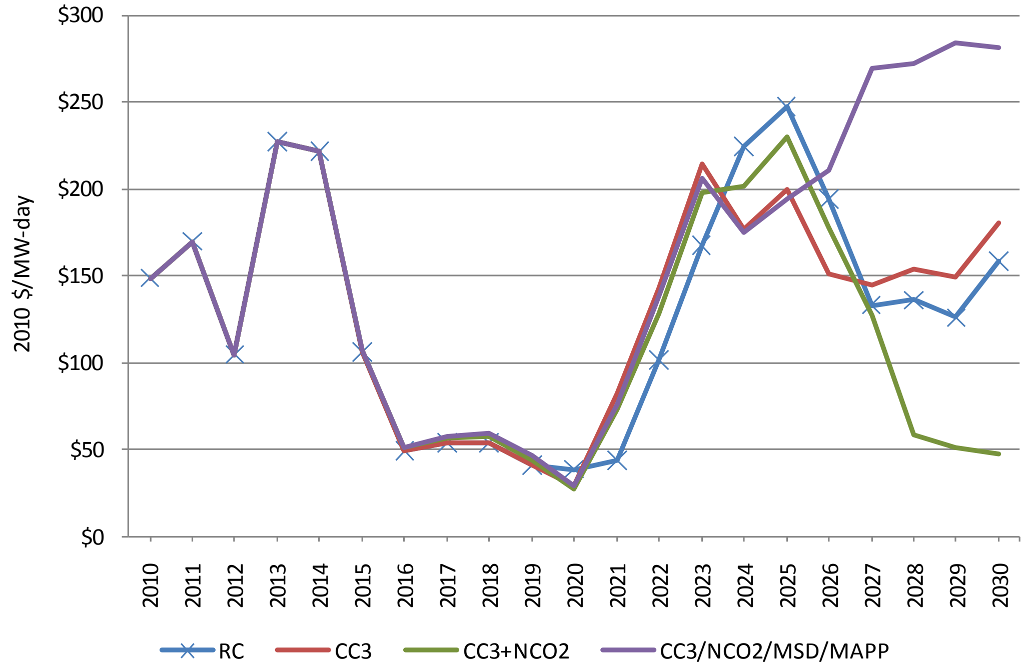


Figure 5.17 PJM-MidE Capacity Prices - CC3 Scenarios



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. 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 Electric Generation CO_2 Emission - Transmission Scenarios[32]

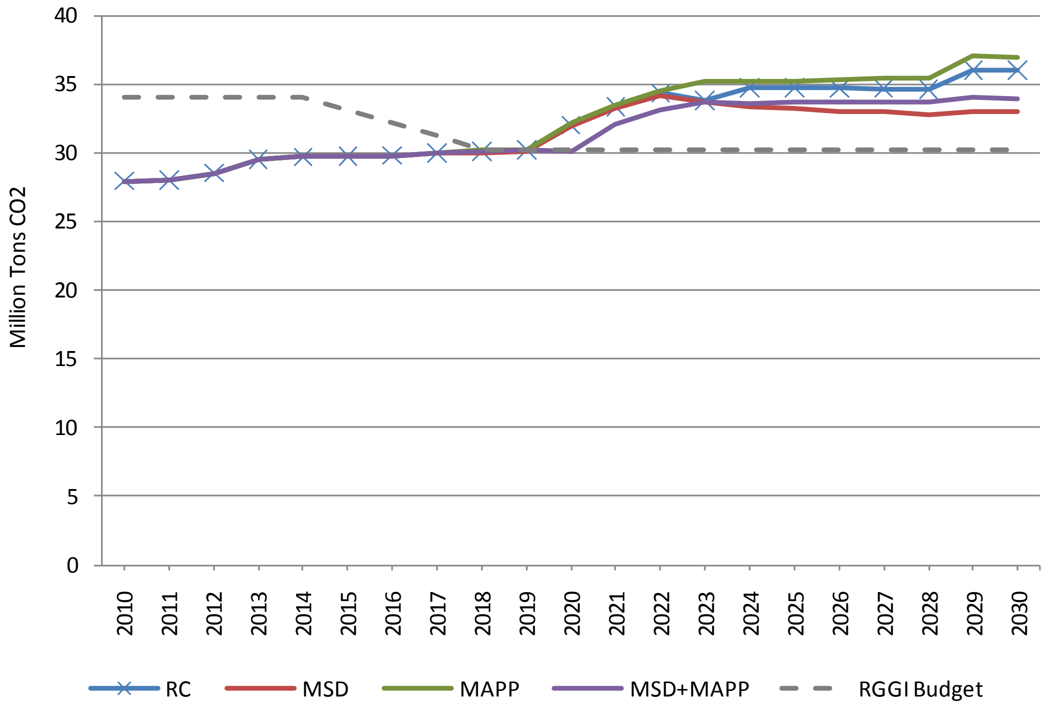
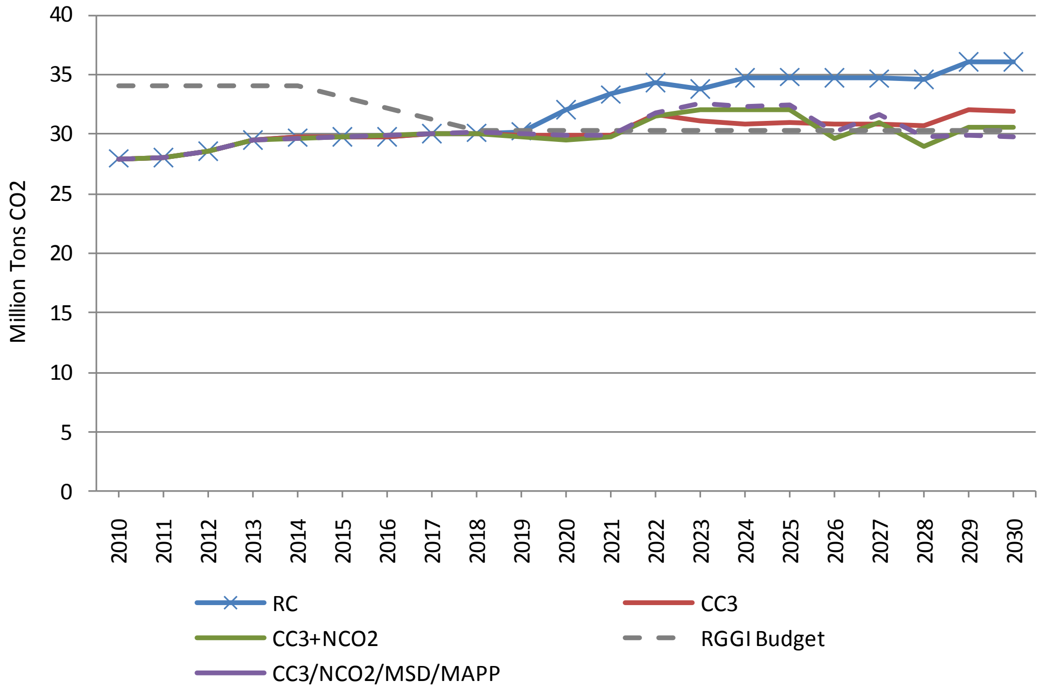


Figure 5.19, below, shows the total Maryland CO_2 emissions under the CC3 scenarios. All of these scenarios result in lower in-State CO_2 emissions. Though emissions under the CC3+NCO2 scenario dip below the RGGI budget, only the combined impacts incorporated in the CC3/NCO2/MSD/MAPP scenario result 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.

[32] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

Figure 5.19 Maryland Electric Generation CO_2 Emissions - CC3 Scenarios[33]



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.

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[33] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

- 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

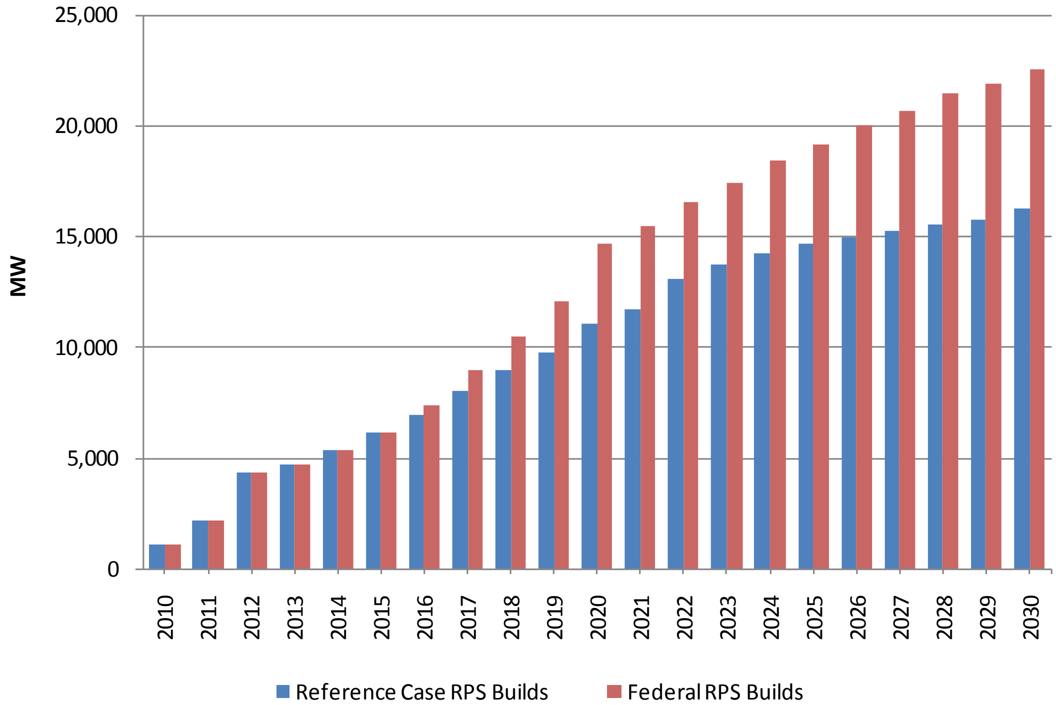
In recent years, Congress has considered enacting legislation to restrict carbon dioxide emissions at the national level and has introduced bills aiming to establish a national-level Renewable Energy Portfolio Standard ("RPS"). While neither a national CO_2 reduction policy nor a national RPS has yet 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 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 – NCO2 Scenarios



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 Economic-Based Plant Retirements - NCO2 Scenarios (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 capture and 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 capture and 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.

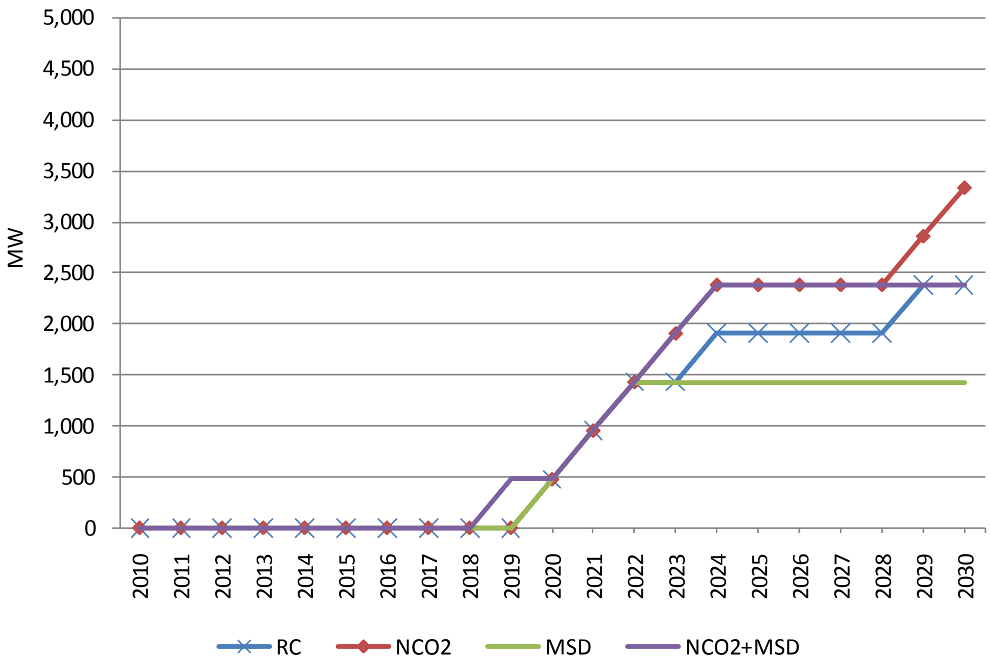
In comparison to the LTER Reference Case and the MSD scenario, the NCO2 scenarios result in about 7,000 MW of additional PJM-wide natural gas power plant additions (see Table 6.2 below). This additional capacity is built because economic natural gas resources displace coal resources in PJM. Although 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 PJM Cumulative Natural Gas Capacity Additions – NCO2 Scenarios (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 – NCO2 Scenarios



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.

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 6.3 PJM-MidE Natural Gas Capacity Additions – NCO2 Scenarios

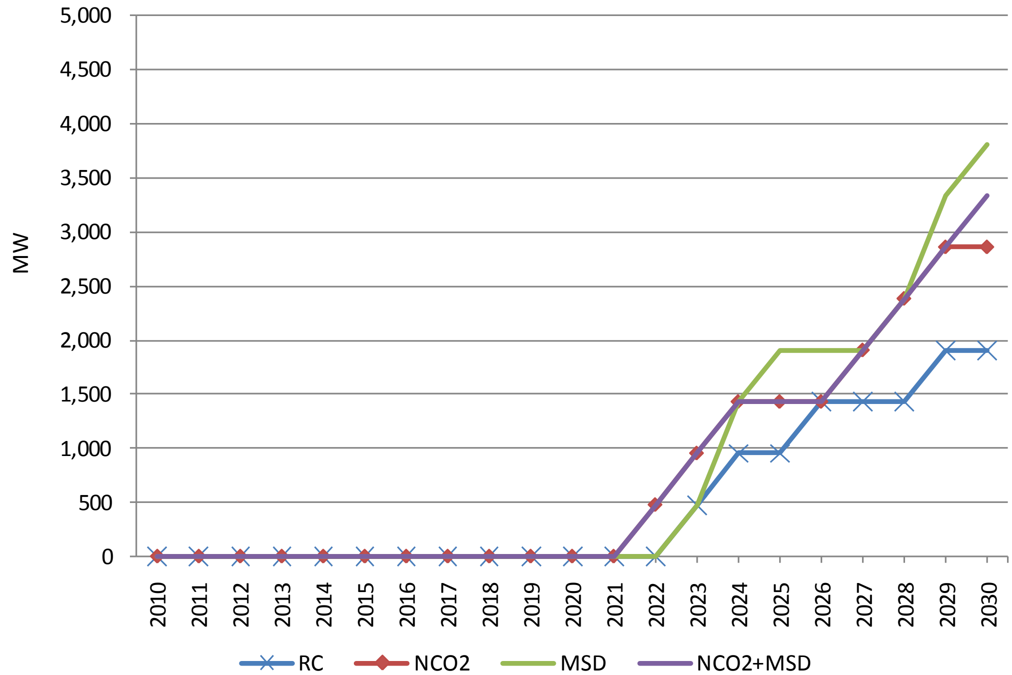
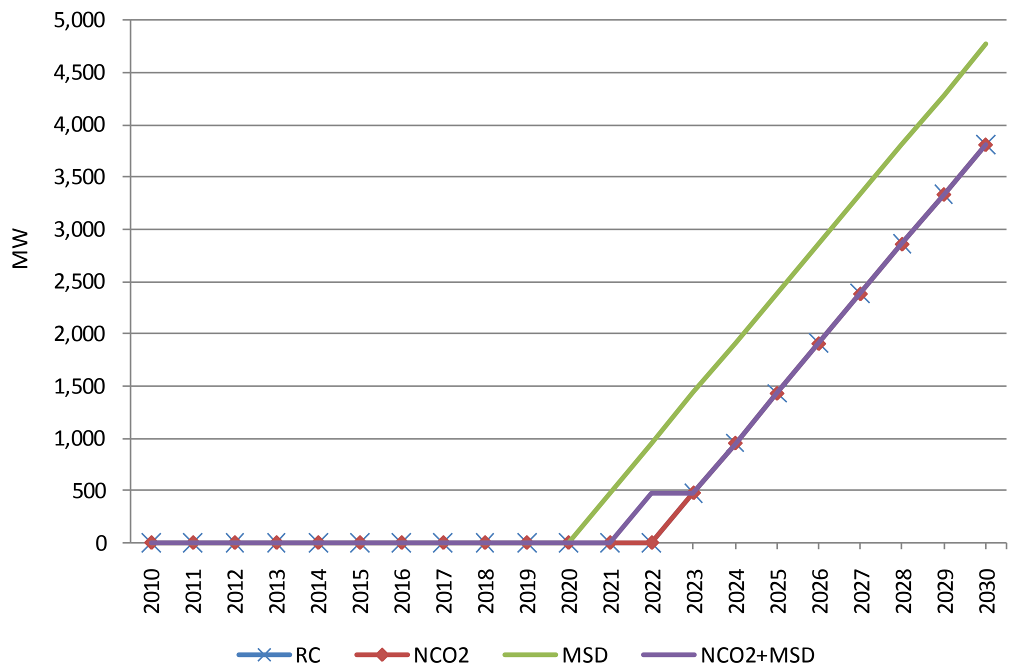


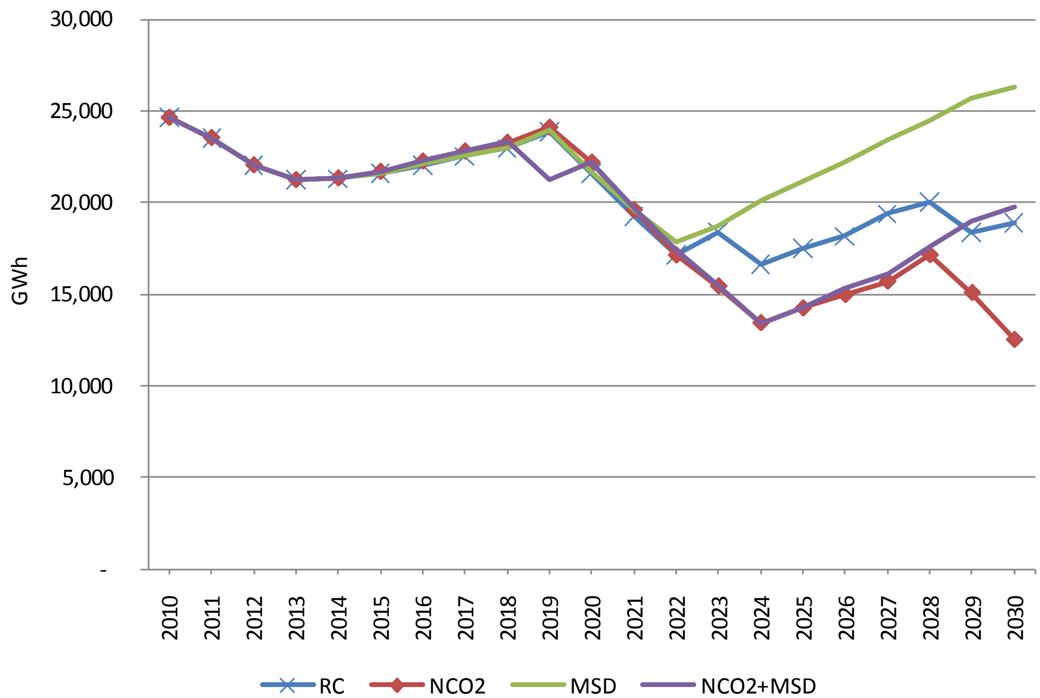
Figure 6.4 PJM-APS Natural Gas Capacity Additions – NCO2 Scenarios



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 – NCO2 Scenarios



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 – NCO2 Scenarios

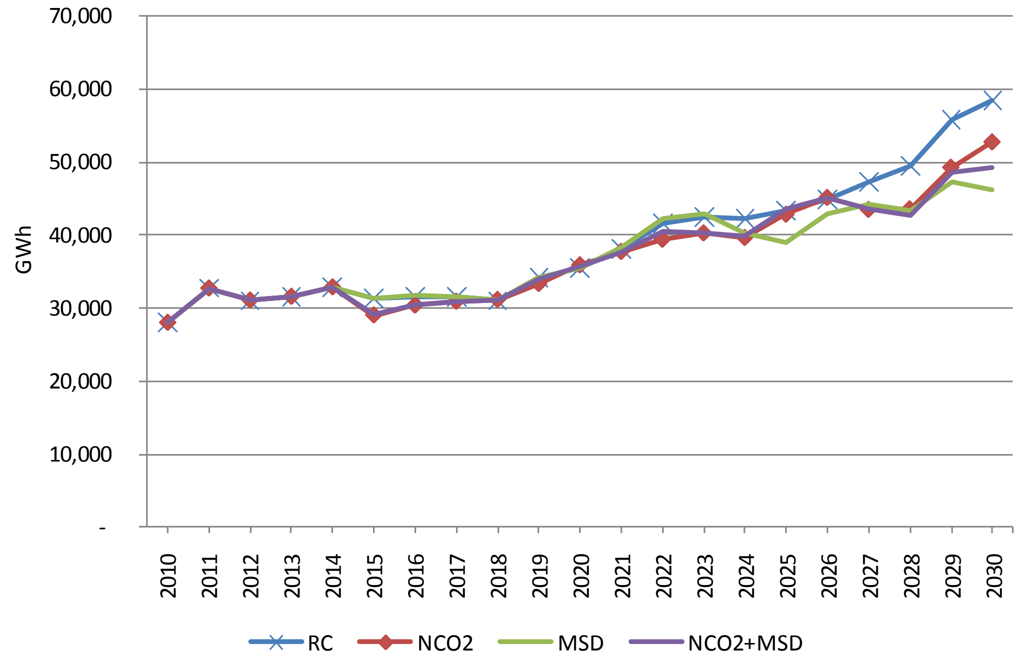
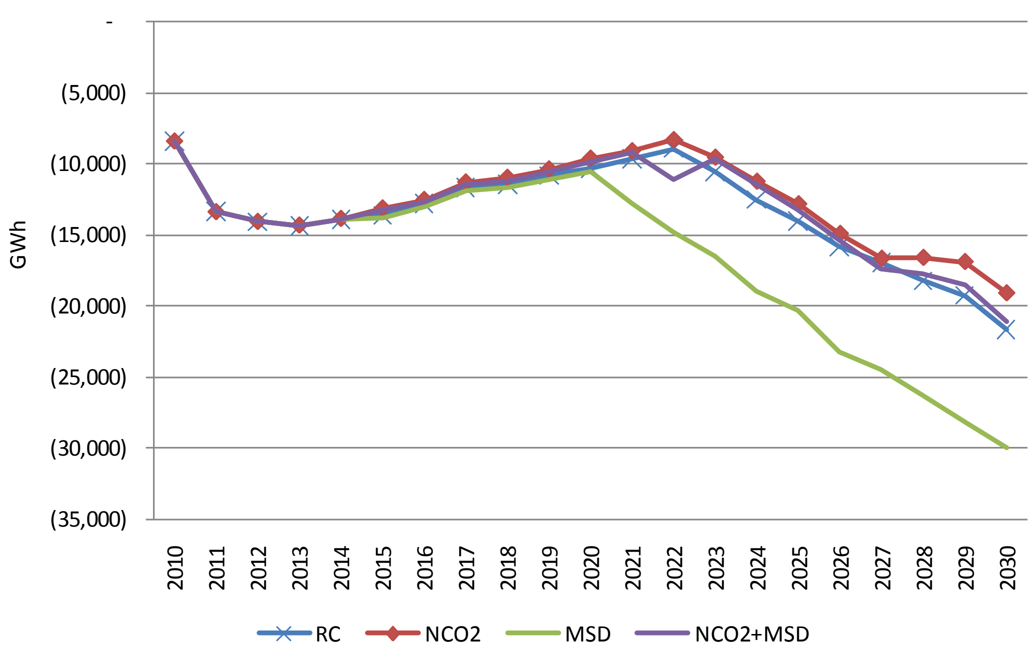


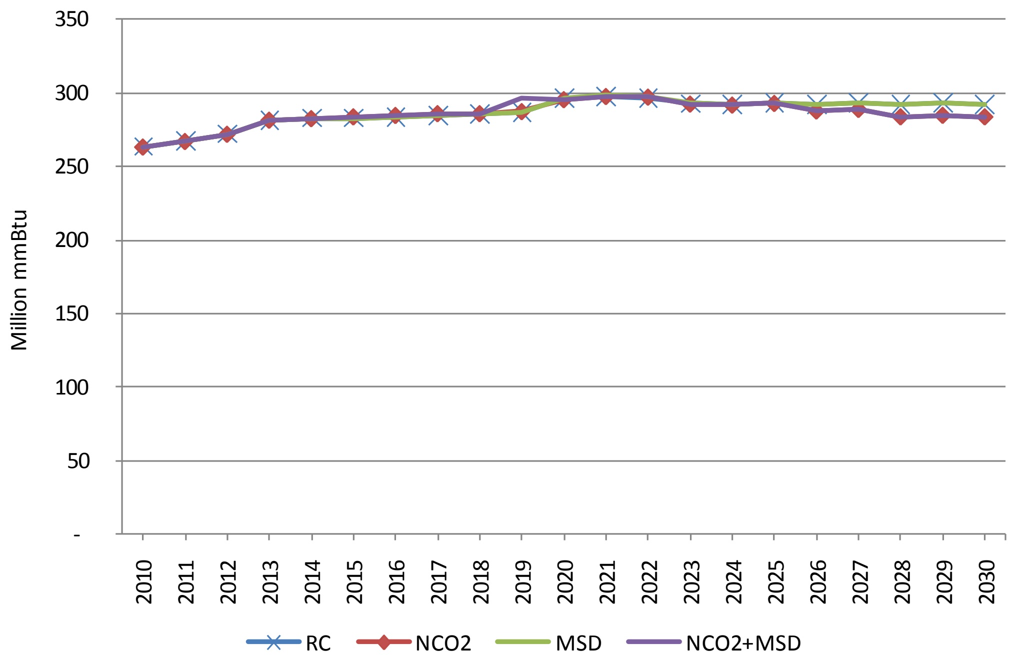
Figure 6.7 PJM-APS Net Imports – NCO2 Scenarios



6.4 Fuel Use

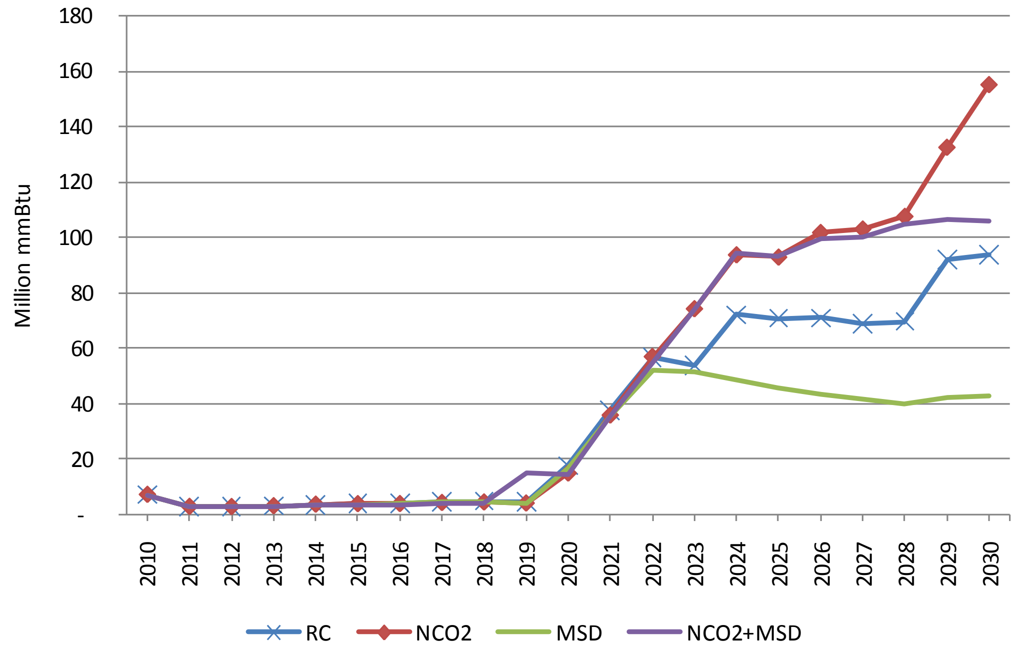
Under both of the NCO2 scenarios there is a small reduction (about 3 percent) in coal consumption for electricity generation in Maryland by 2030 (see Figure 6.8 below). This is due to a reduction in coal-fired generating capacity associated with retrofit de-rates.

Figure 6.8 Coal Use for Electricity Generation in Maryland – NCO2 Scenarios



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 Use for Electricity Generation in Maryland – NCO2 Scenarios



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.

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 increase by about 13 percent in PJM-MidE (Figure 6.11 below) and by about 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 6.10 PJM-SW Real All-Hours Energy Prices – NCO2 Scenarios

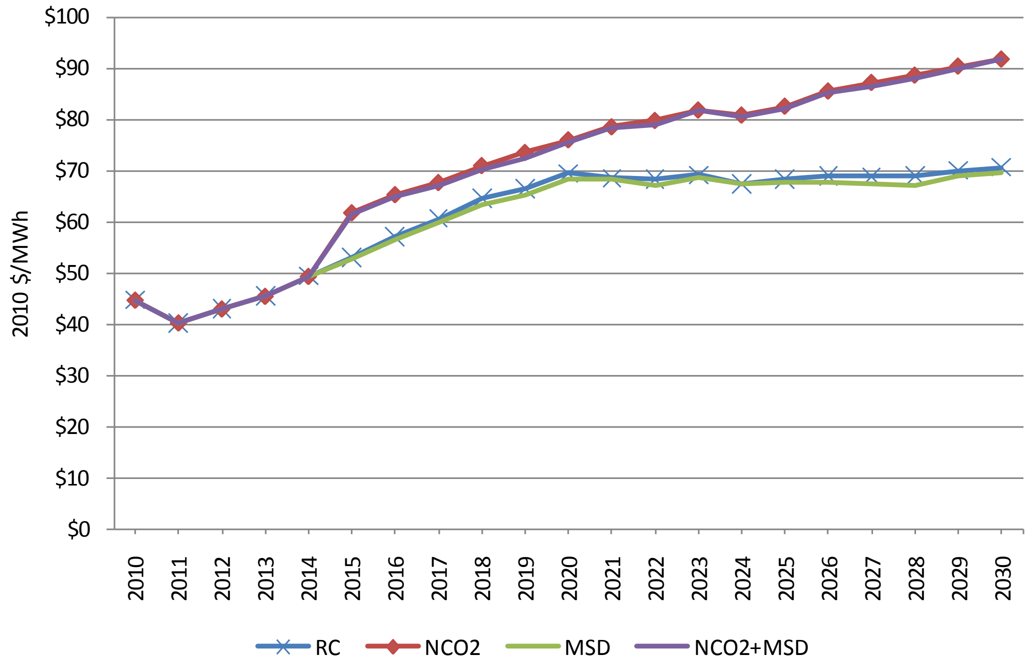


Figure 6.11 PJM-MidE Real All-Hours Energy Prices – NCO2 Scenarios

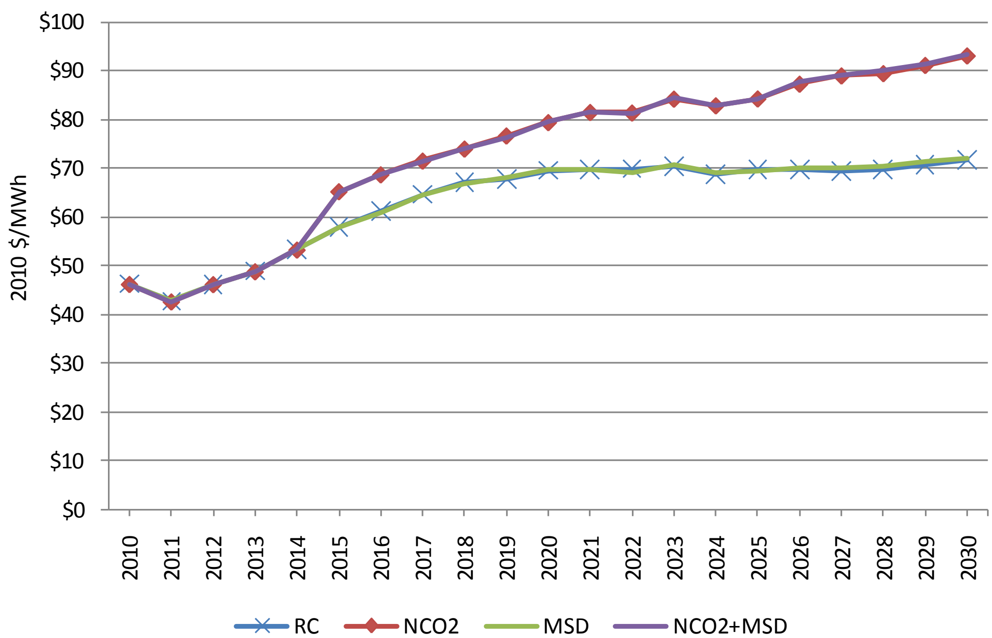
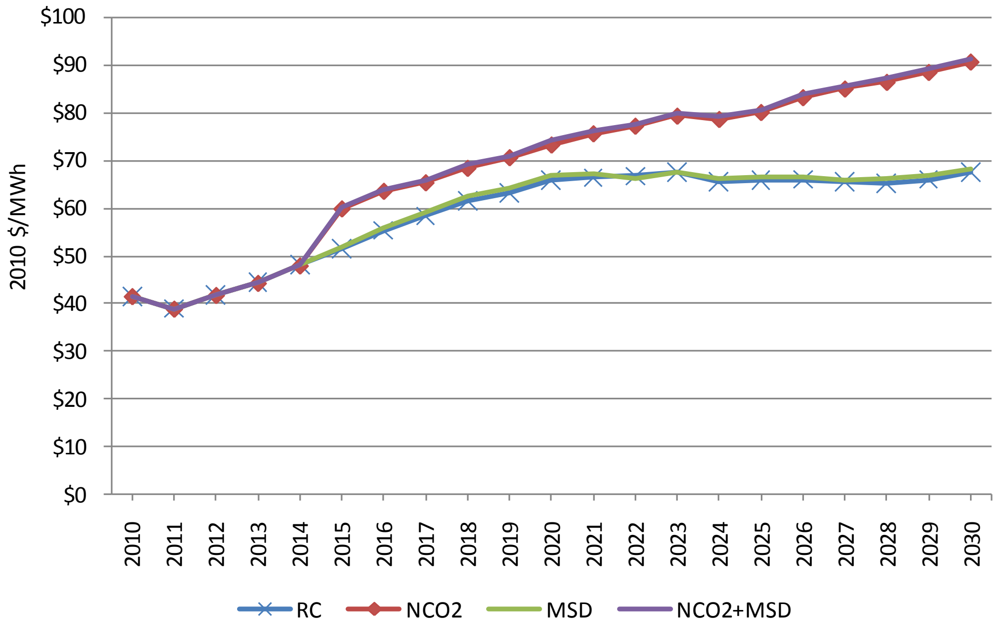


Figure 6.12 PJM-APS Real All-Hours Energy Prices – NCO2 Scenarios



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 – NCO2 Scenarios

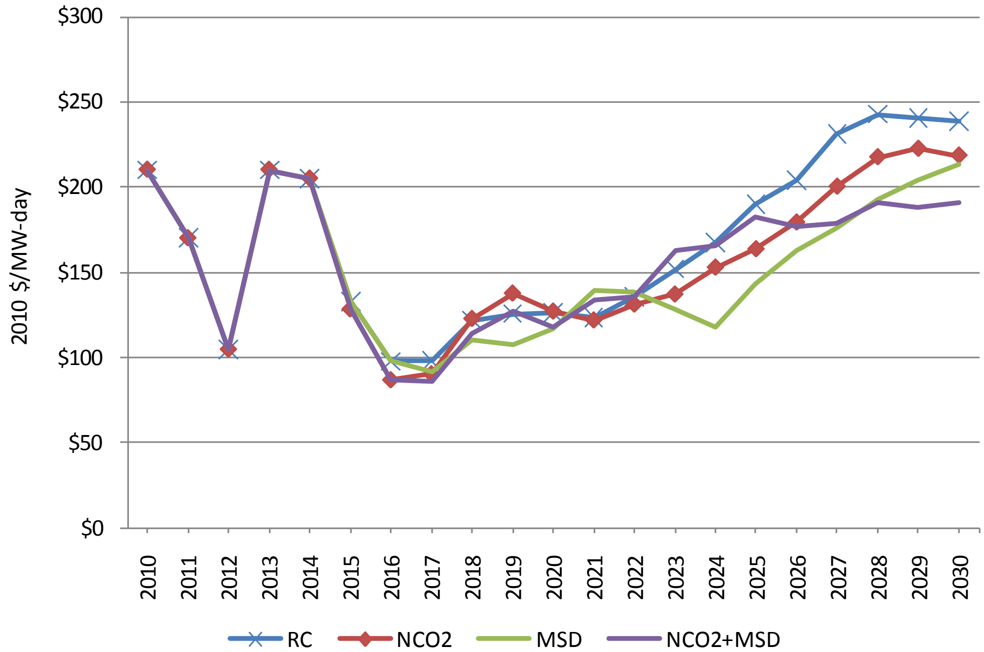


Figure 6.14, below, shows the capacity costs in the PJM-MidE area. As was the case for capacity prices in PJM-SW, capacity prices in PJM-MidE exhibit little differences among the scenarios until the early to mid-2020s. Throughout the period, both of the national carbon legislation scenarios track together, 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.

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 6.14 PJM-MidE Capacity Prices – NCO2 Scenarios

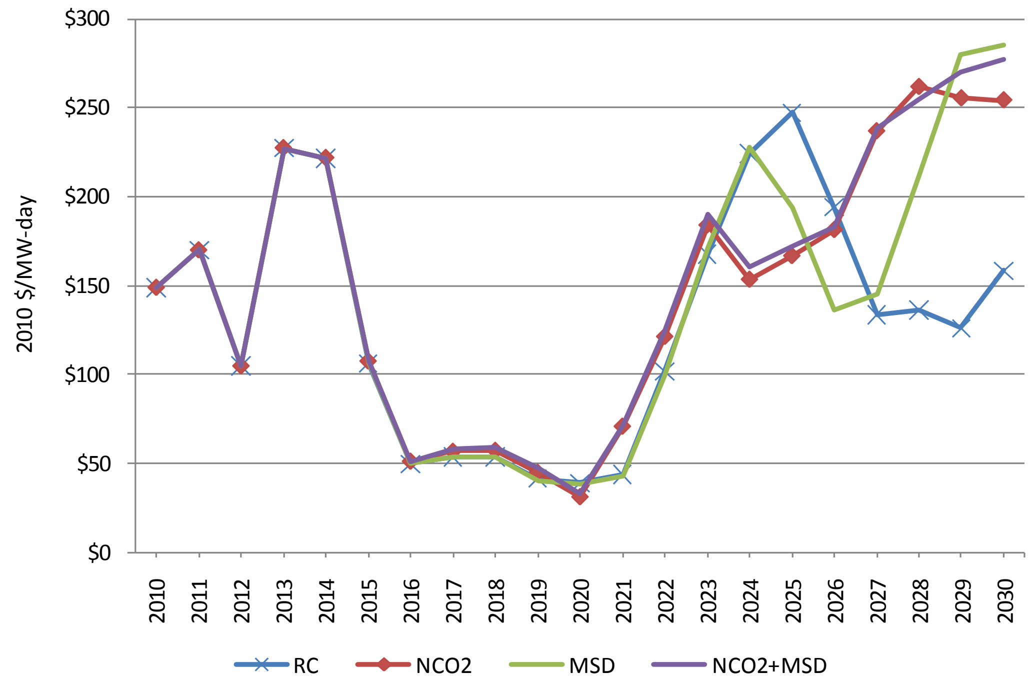
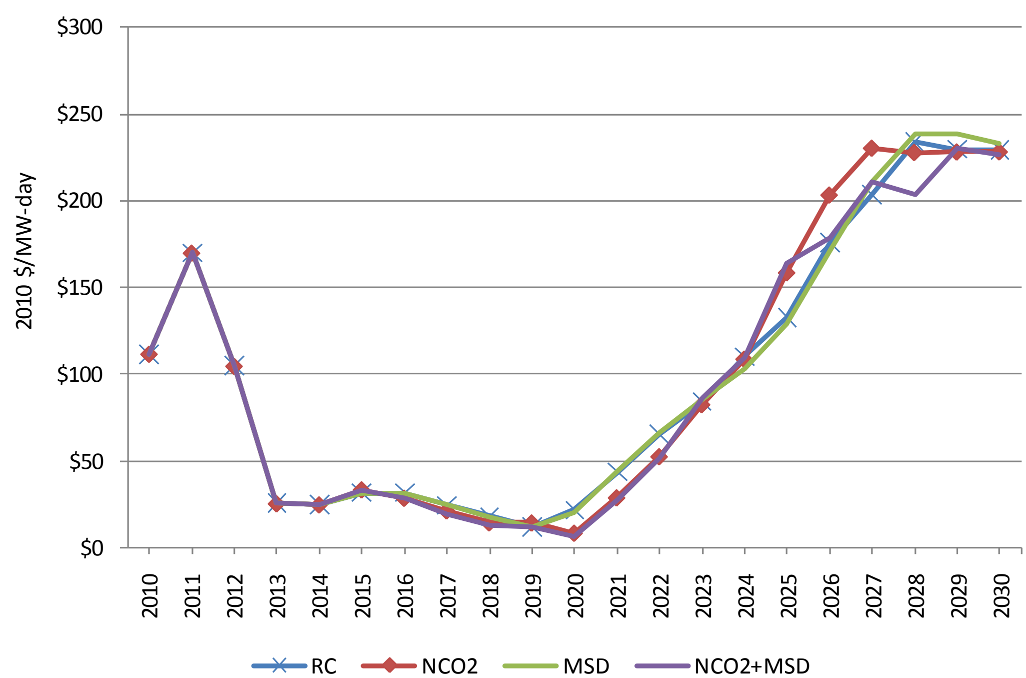


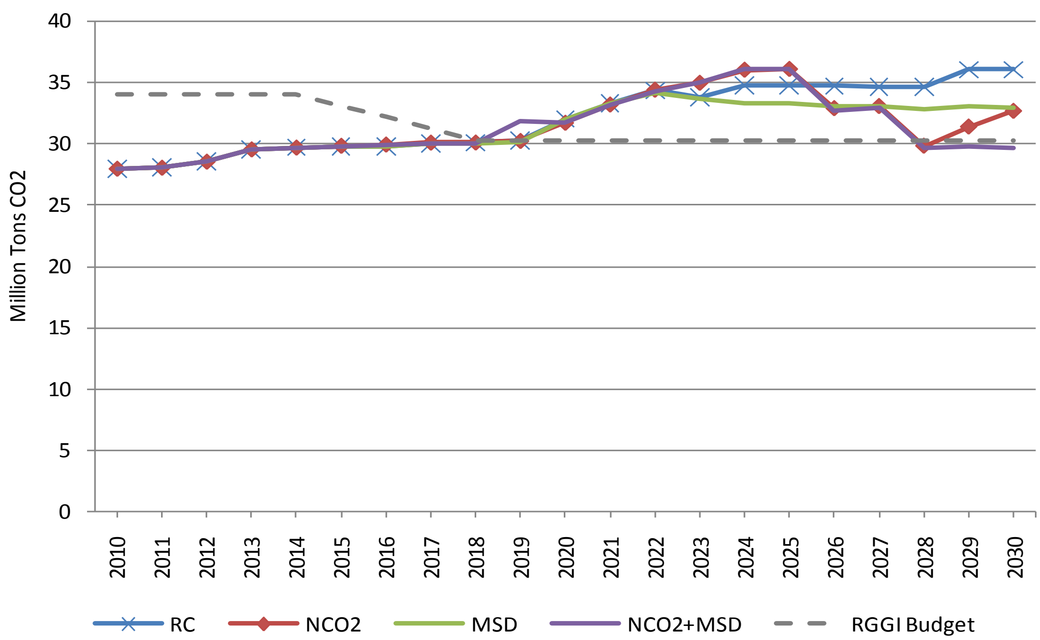
Figure 6.15 PJM-APS Capacity Prices – NCO2 Scenarios



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 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 in 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 Electric Generation CO_2 Emissions – NCO2 Scenarios[34]



[34] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

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, after which time 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.

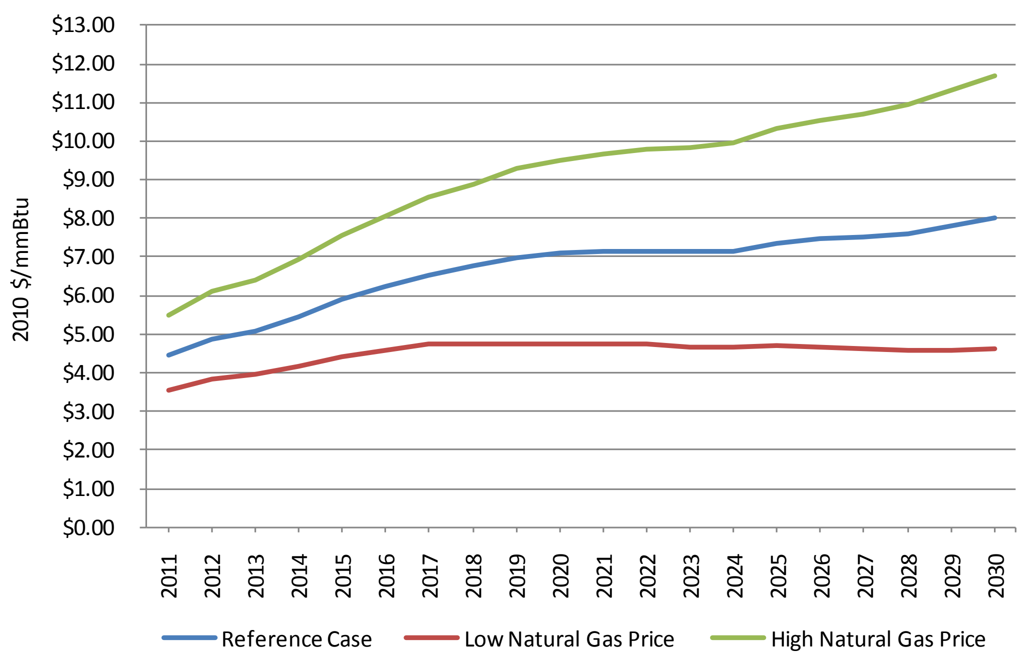
7. HIGH AND LOW NATURAL GAS PRICE ALTERNATIVE SCENARIOS

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 run 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 – High/Low Gas Price Scenarios

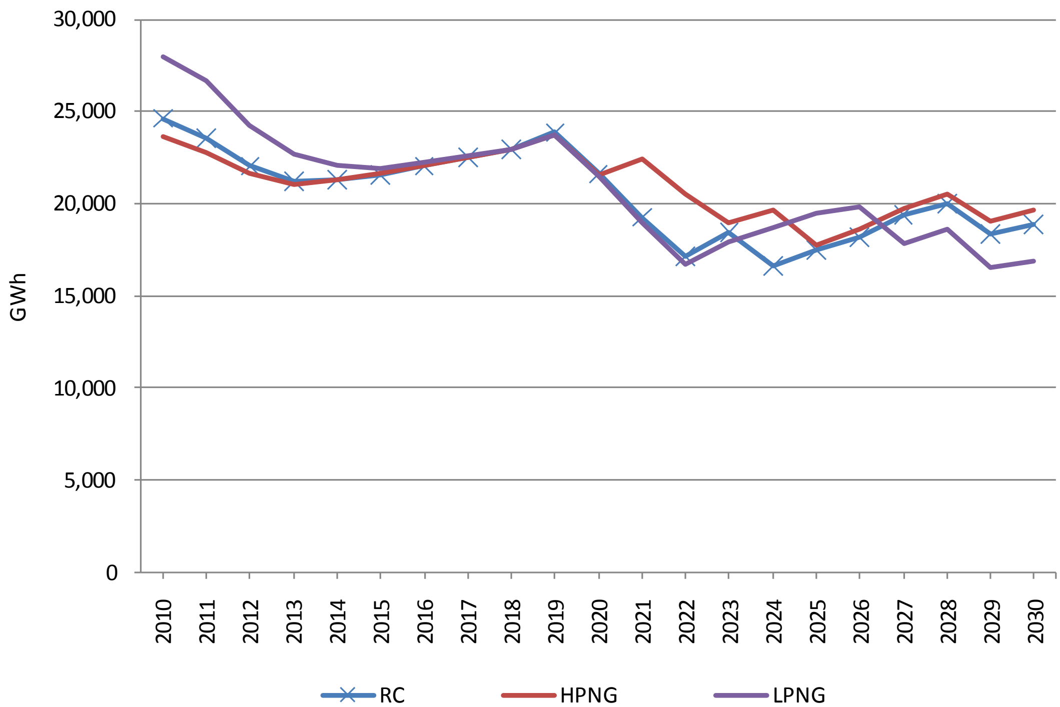
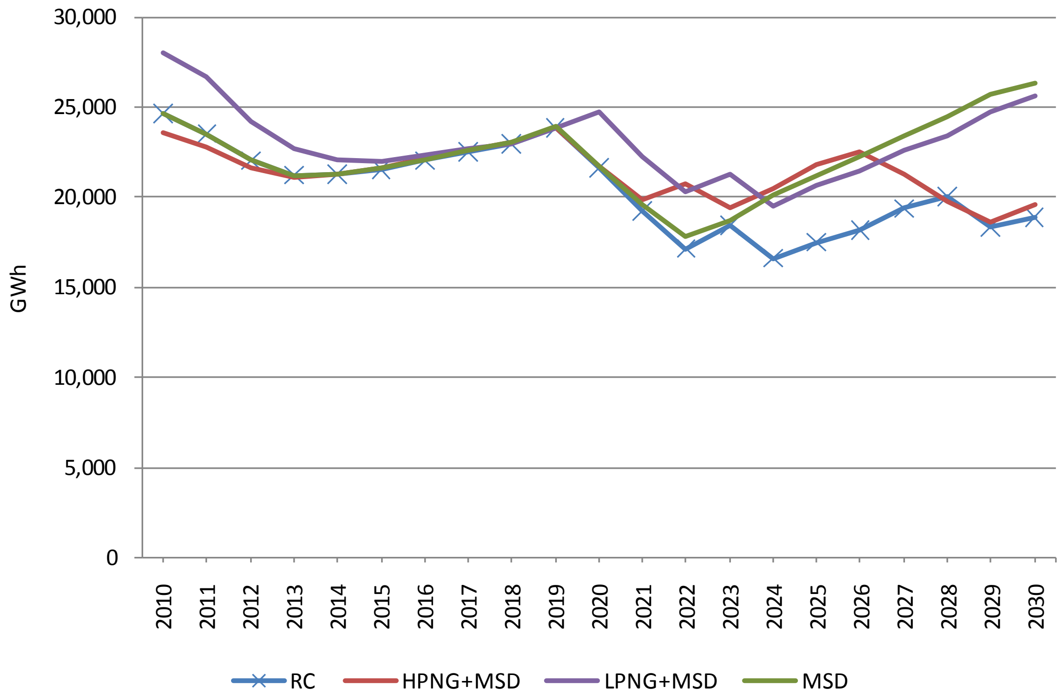


Figure 7.3 PJM-SW Net Imports – High/Low Gas Price and MSD Scenarios



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 scenario 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.

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 7.4 PJM-MidE Net Imports – High/Low Gas Price Scenarios

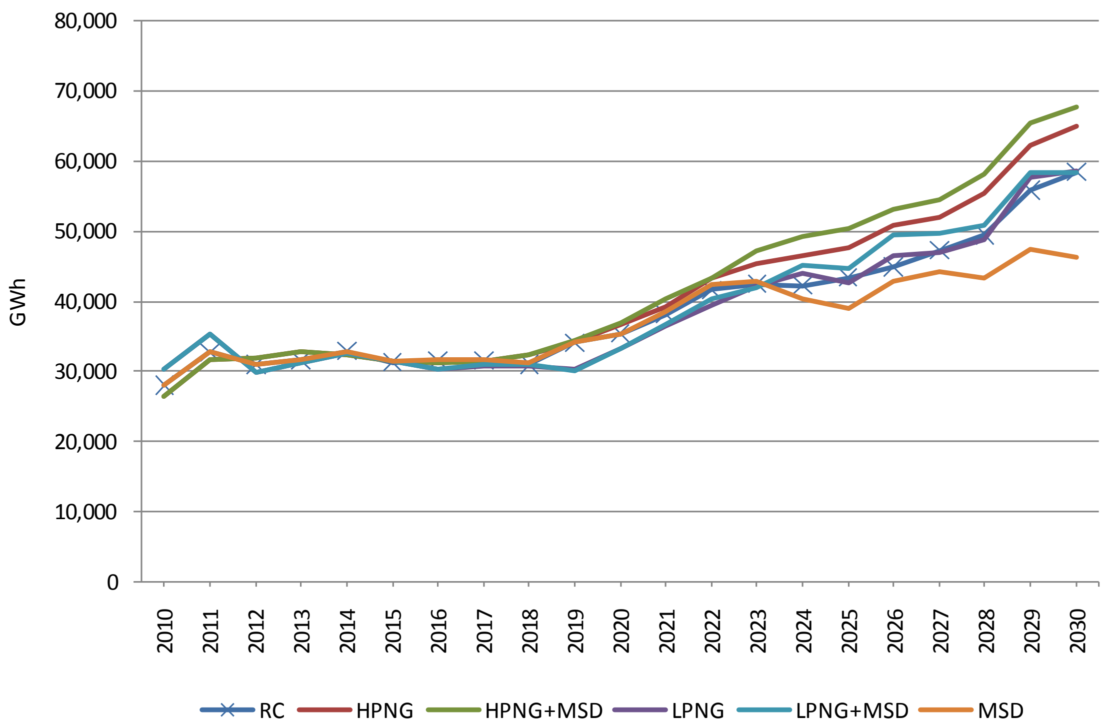
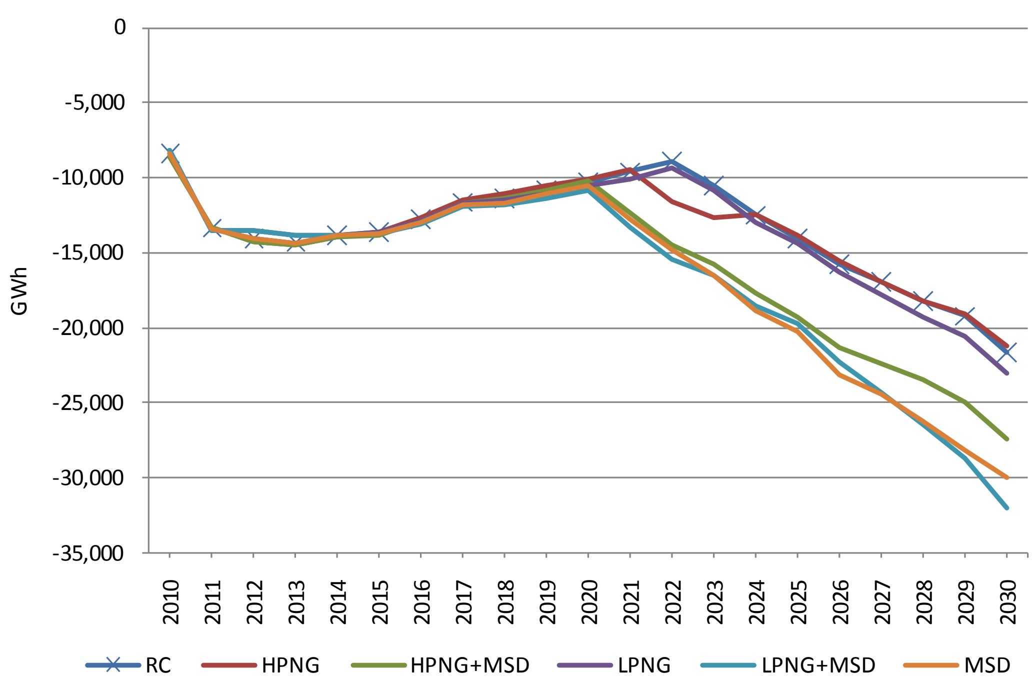


Figure 7.5 PJM-APS Net Imports – High/Low Gas Price Scenarios



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, 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 combined cycle 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 PJM Cumulative Generation Additions - HPNG

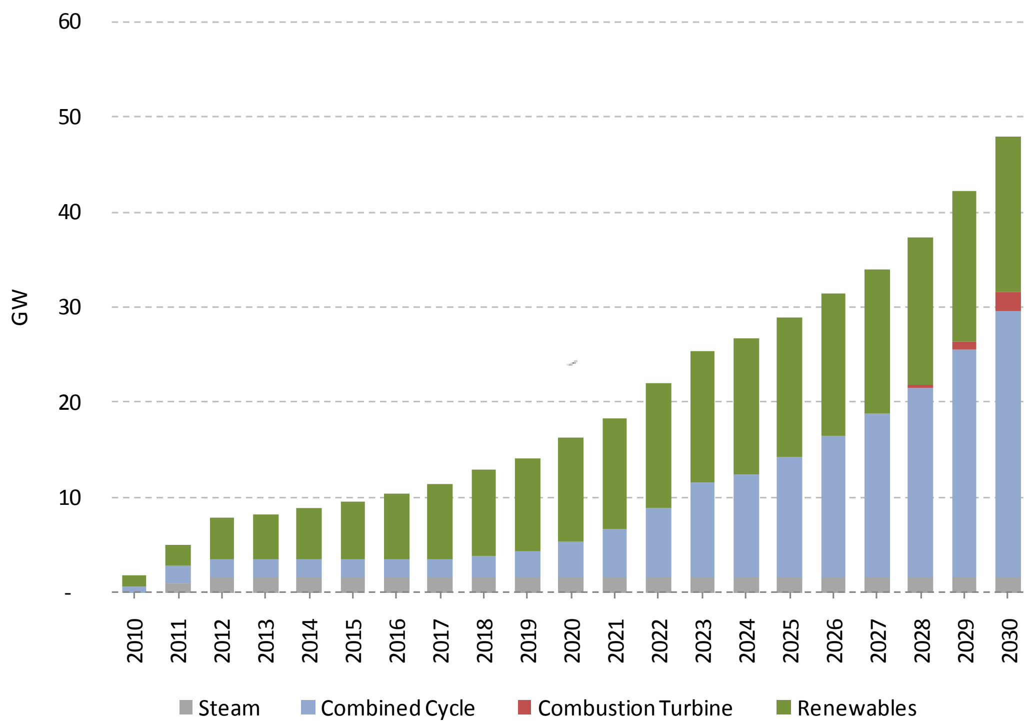


Figure 7.7 PJM Cumulative Generation Additions - LPNG

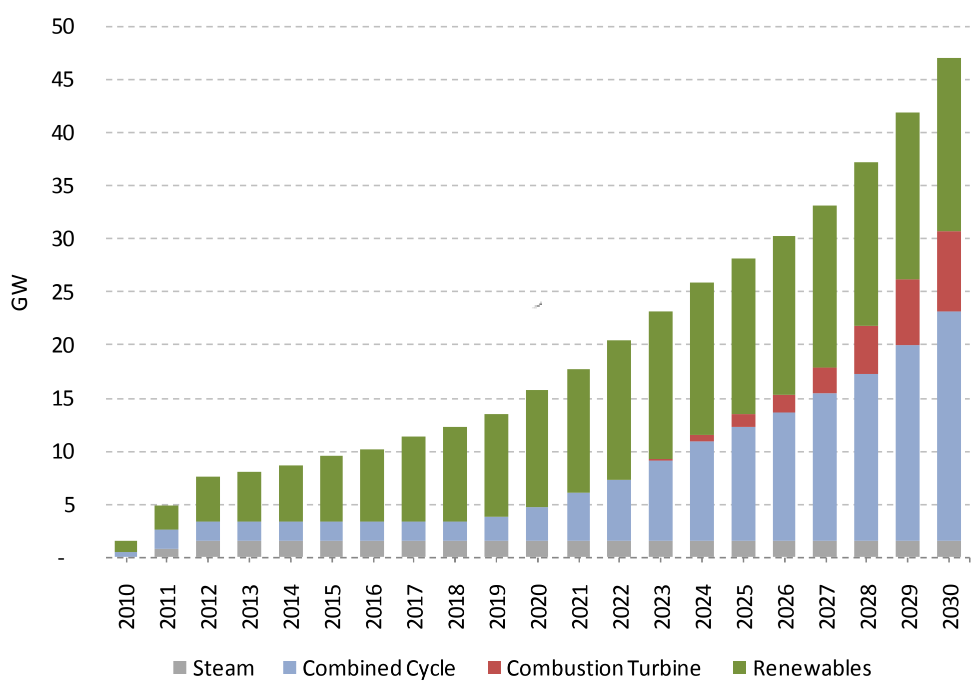


Table 7.1, below, shows the cumulative natural gas capacity additions for the Maryland-relevant zones under the various natural gas price scenarios. Total PJM capacity additions vary only slightly as load growth is the same as in the LTER Reference Case. The differences in total PJM builds is mainly 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 – High/Low Gas Price Scenarios (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 transmission line gives PJM-SW and PJM-MidE access to more imports from lower-cost PJM-APS zone. 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 – High/Low Gas Price Scenarios (%)

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.

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 7.8 Coal Use for Electricity Generation in Maryland – High/Low Gas Price Scenarios

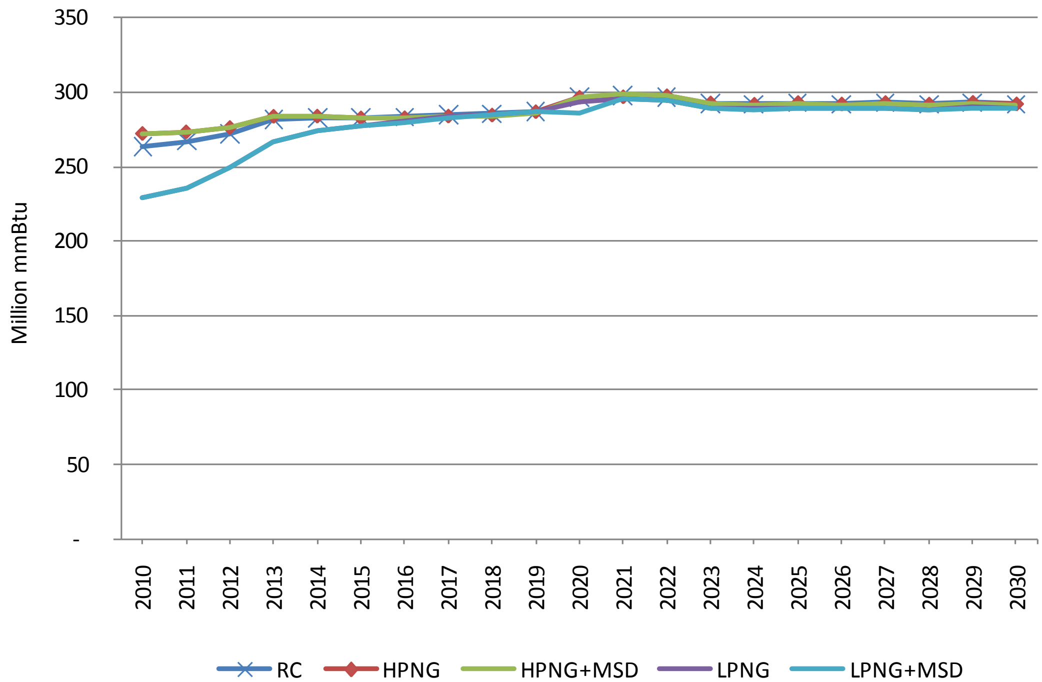
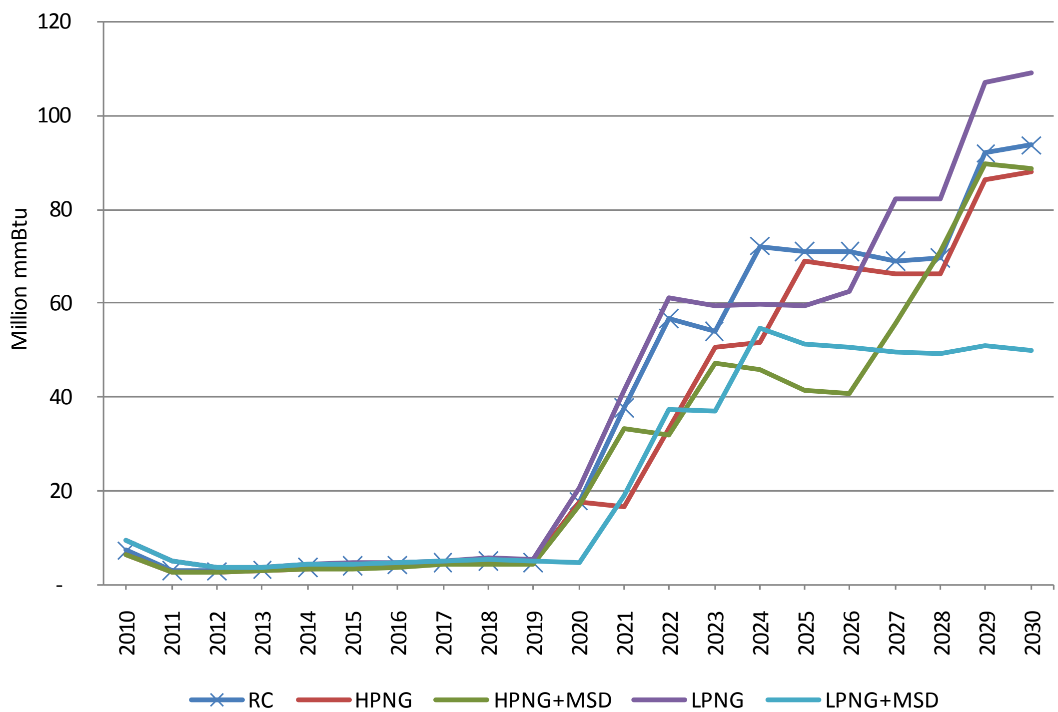


Figure 7.9 Natural Gas Use for Electricity Generation in Maryland – High/Low Gas Price Scenarios



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 – High/Low Gas Price Scenarios

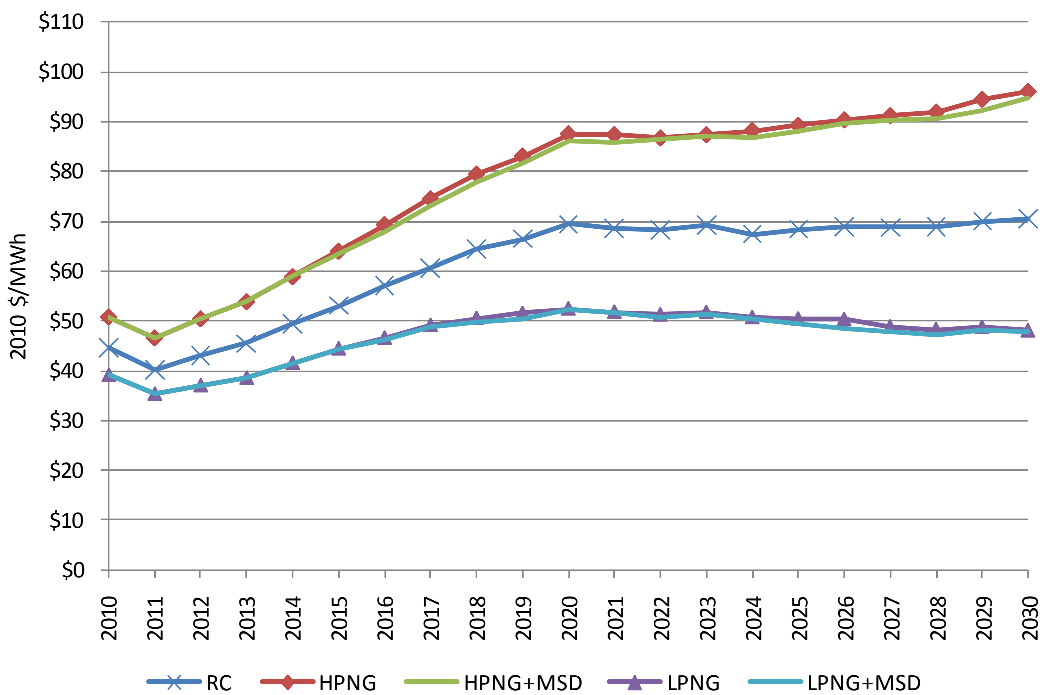


Figure 7.11 PJM-MidE Real All-Hours Energy Prices – High/Low Gas Price Scenarios

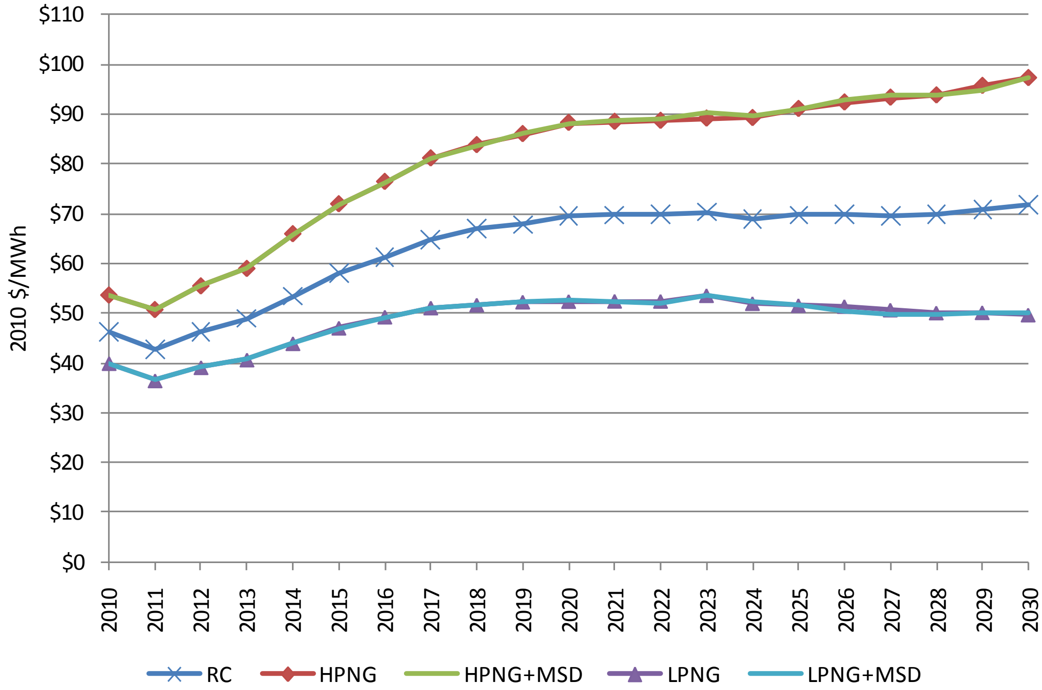
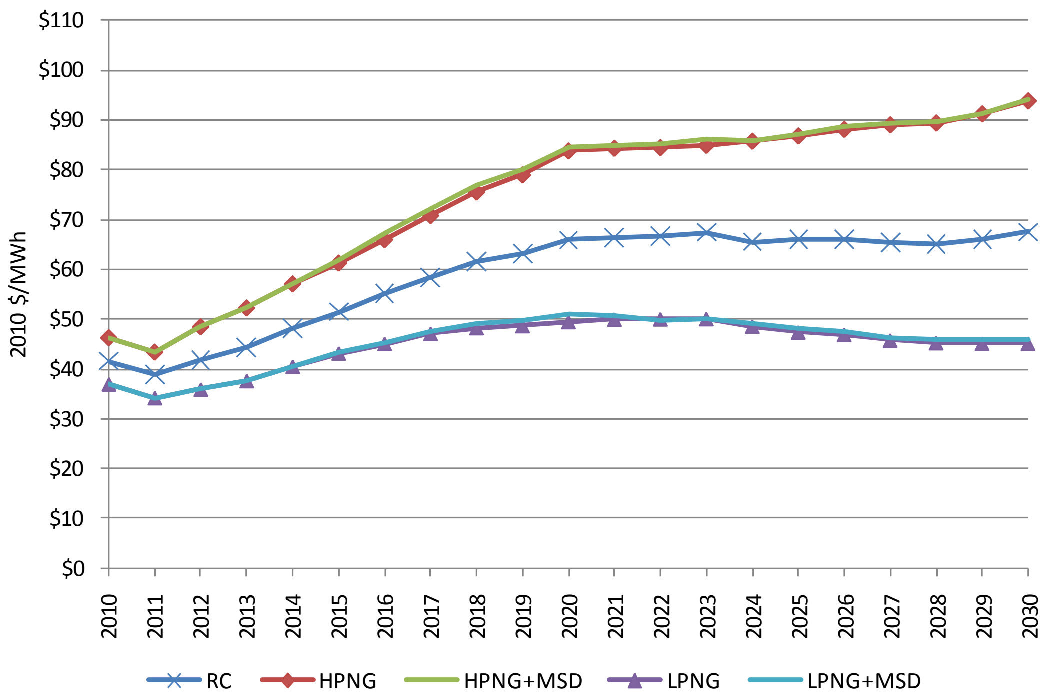


Figure 7.12 PJM-APS Real All-Hours Energy Prices – High/Low Gas Price Scenarios

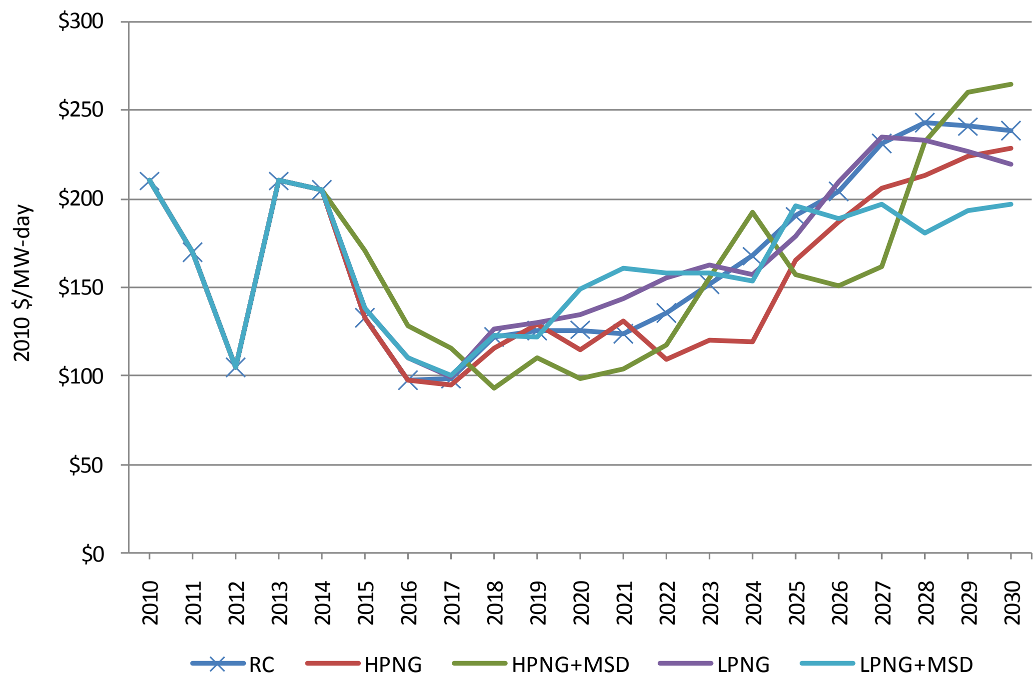


Although the impact of either higher or lower natural gas prices on overall energy prices is clear, Maryland's ability to influence the price of natural gas through measures to encourage additional natural gas supply or to limit demand for natural gas is extremely limited. As noted earlier, natural gas 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

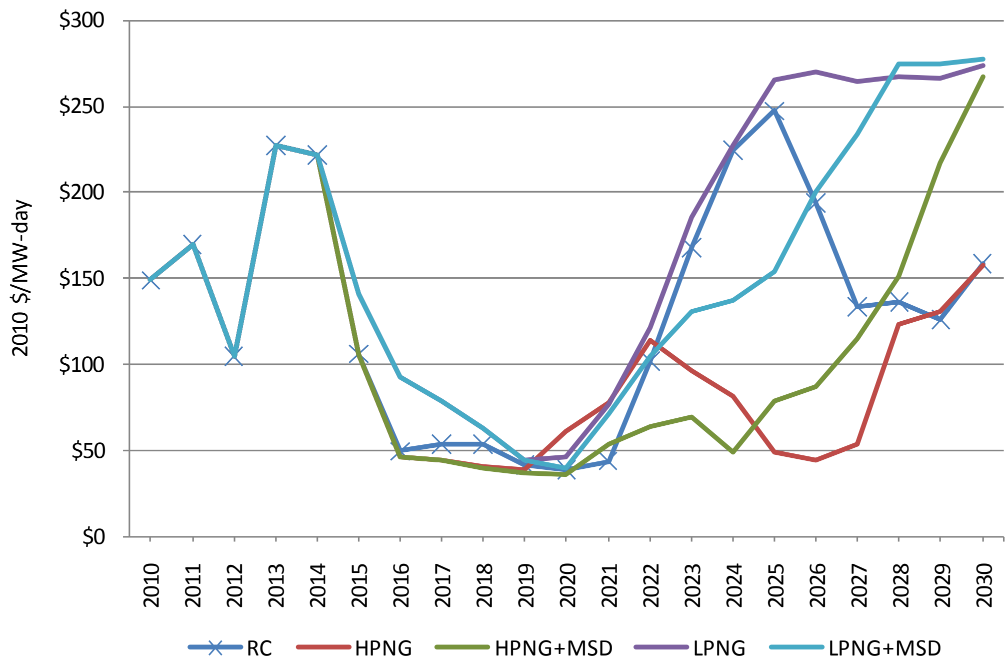
Capacity prices for PJM-SW are shown in Figure 7.13, below. In general, the trend in capacity prices is similar under all of the alternative natural gas price scenarios though capacity prices under the higher natural gas price scenarios are consistently lower than the LTER Reference Case prices. The 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 – High/Low Gas Price Scenarios



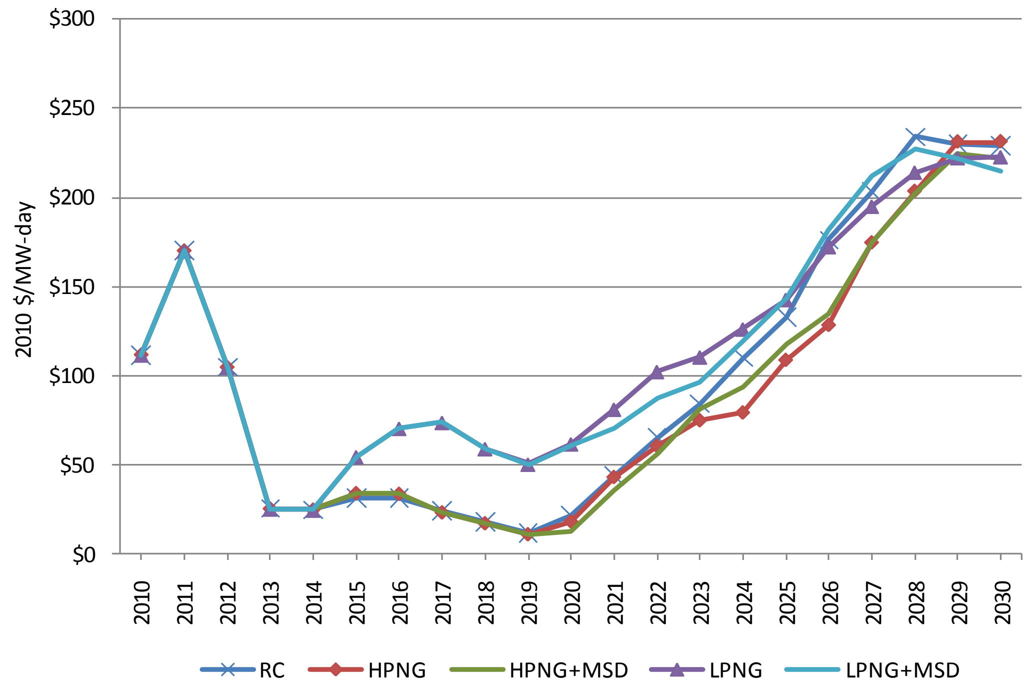
Capacity prices simulated for the PJM-MidE zone are shown in Figure 7.14, below, and exhibit the same volatility that is characteristic of this zone. Capacity prices diverge from 2022 through 2030 because they are highly sensitive to the power plant construction schedule. As was the case for the PJM-SW 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 – High/Low Gas Price Scenarios



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 – High/Low Gas Price Scenarios



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, though 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 Maryland HAA Plant SO_2 Emissions – High/Low Gas Price Scenarios

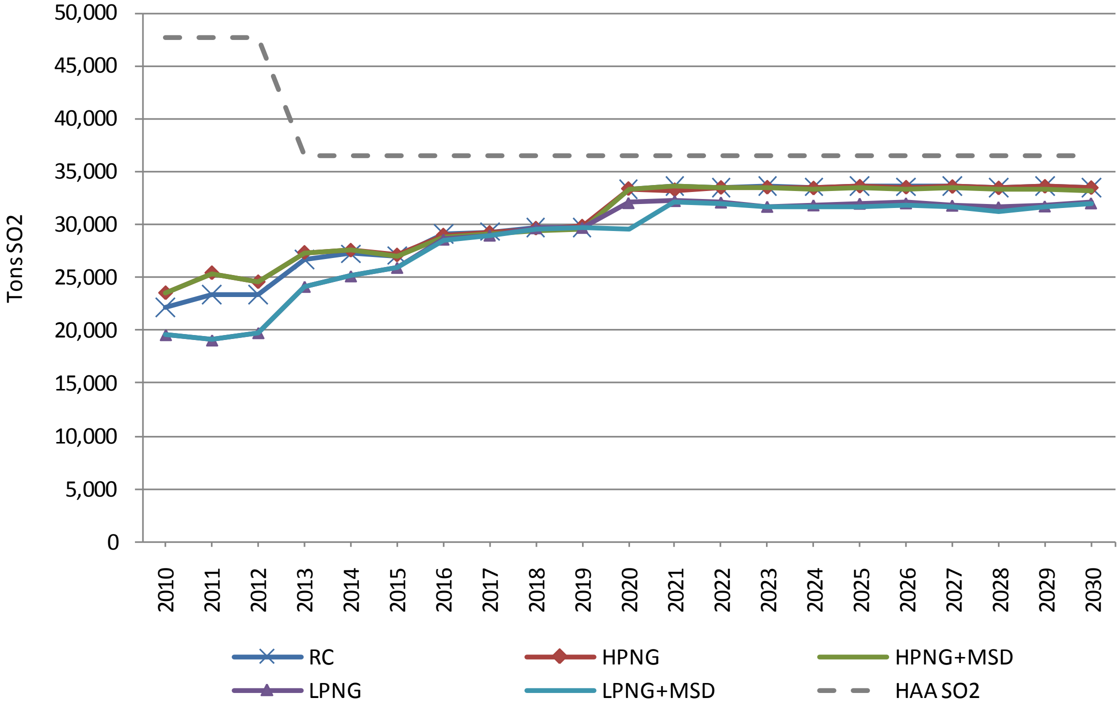
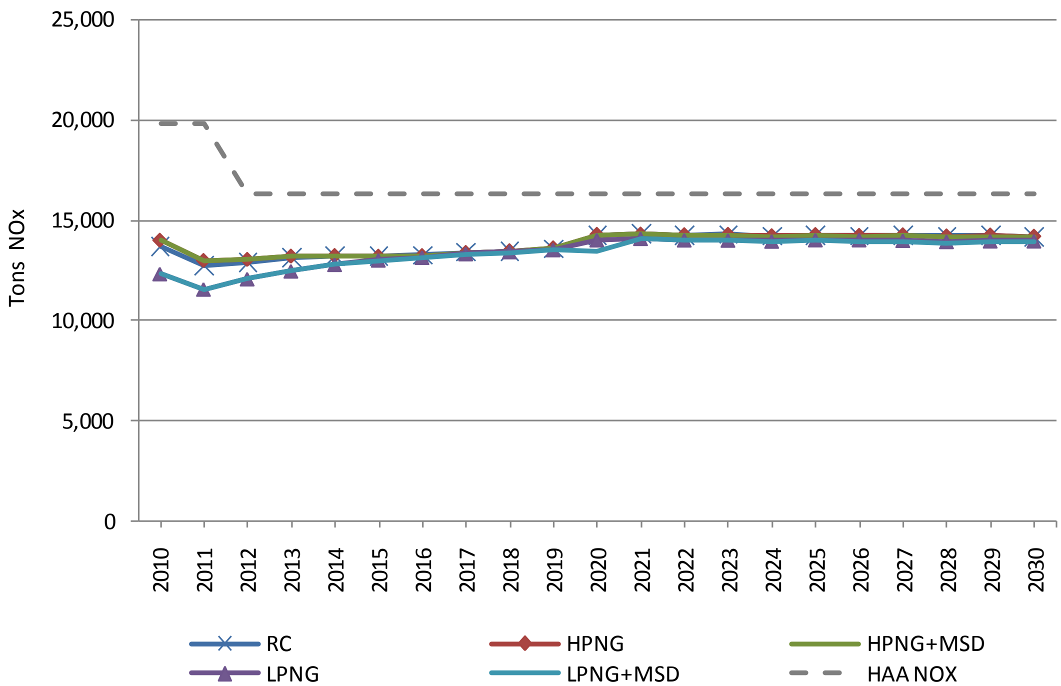
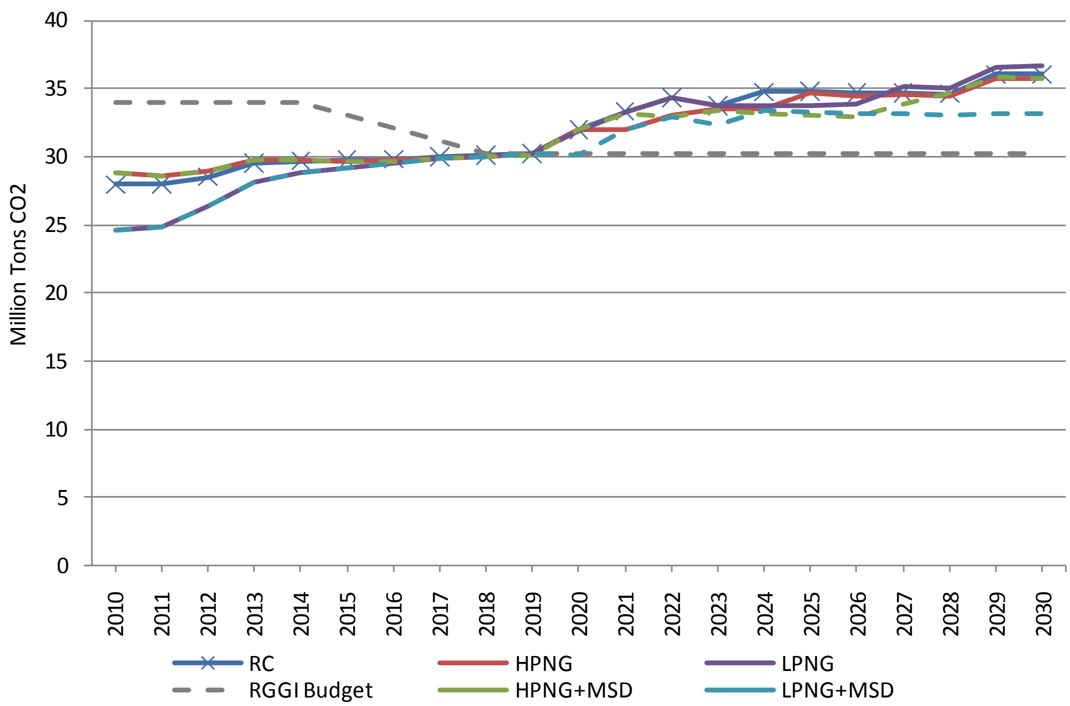


Figure 7.17 Maryland HAA Plant NO_x Emissions – High/Low Gas Price Scenarios



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) 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 Electric Generation CO_2 Emissions - High/Low Gas Price Scenarios[35]



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.

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[35] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

- 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

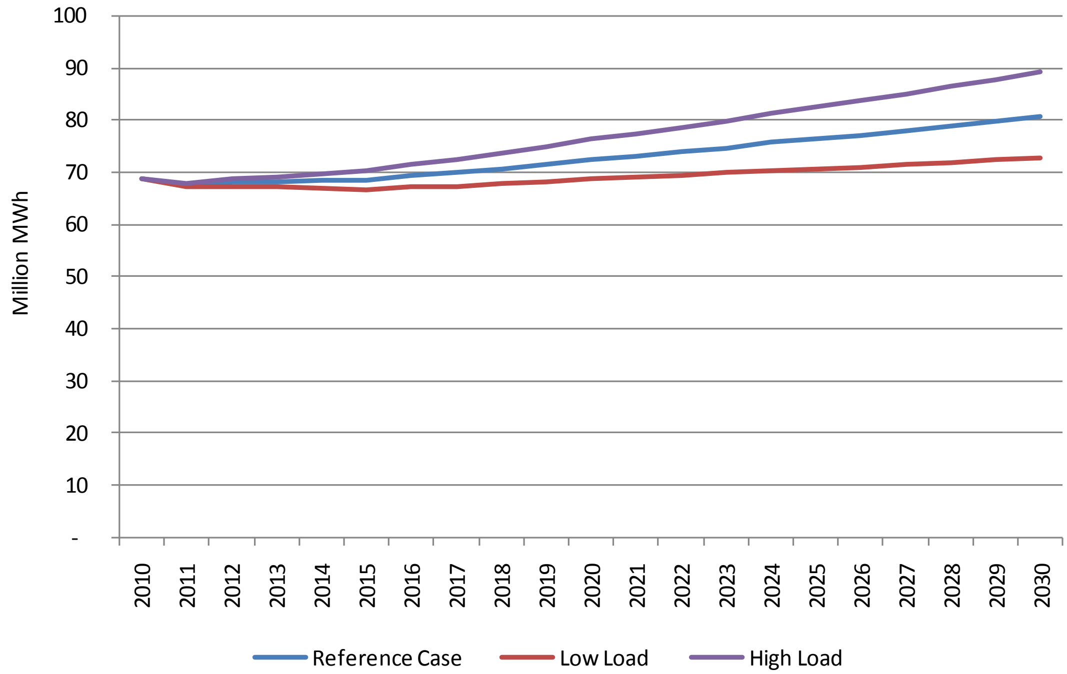
8.1 Introduction

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 – High/Low Load Scenarios



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 – High/Low Load Scenarios

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 – High/Low Load Scenarios (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.

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 8.2 PJM-SW Net Imports – High/Low Load Scenarios

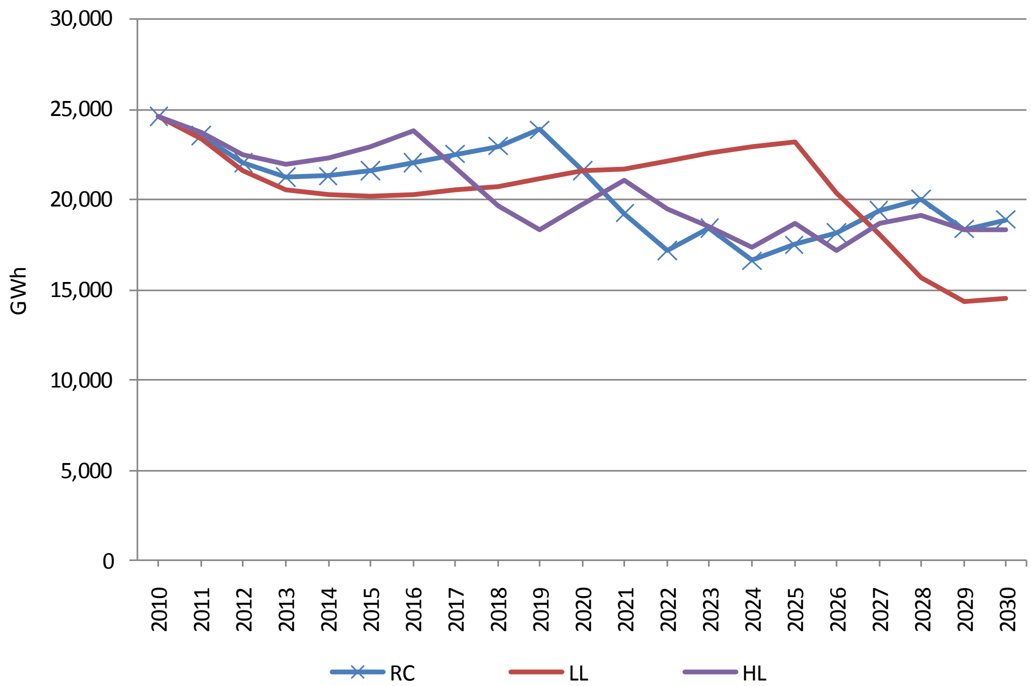
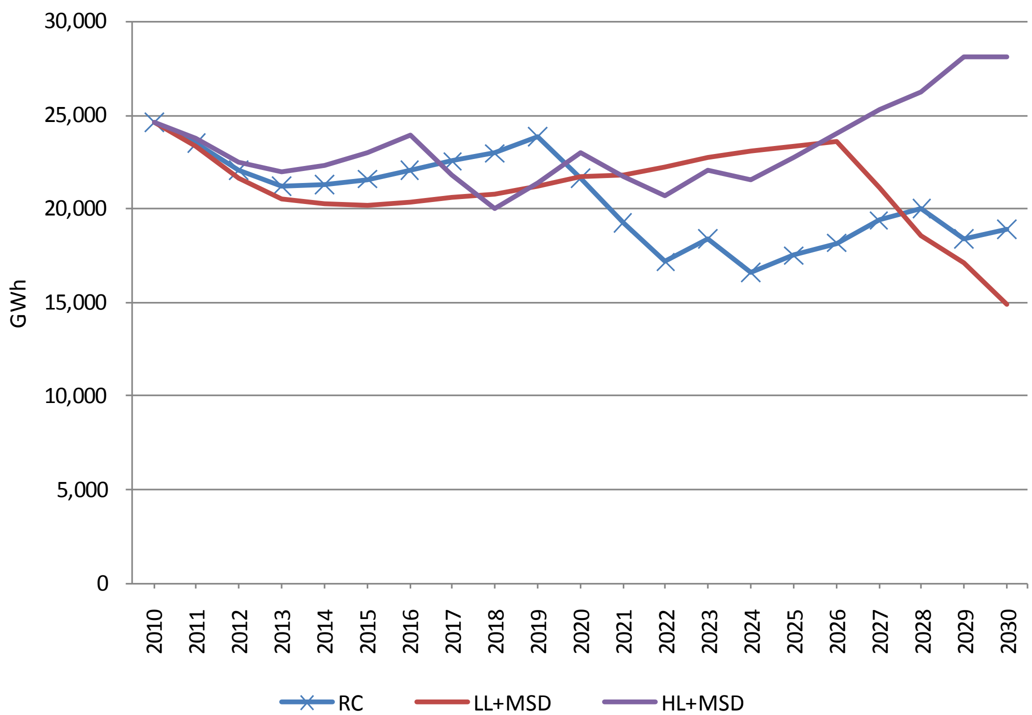
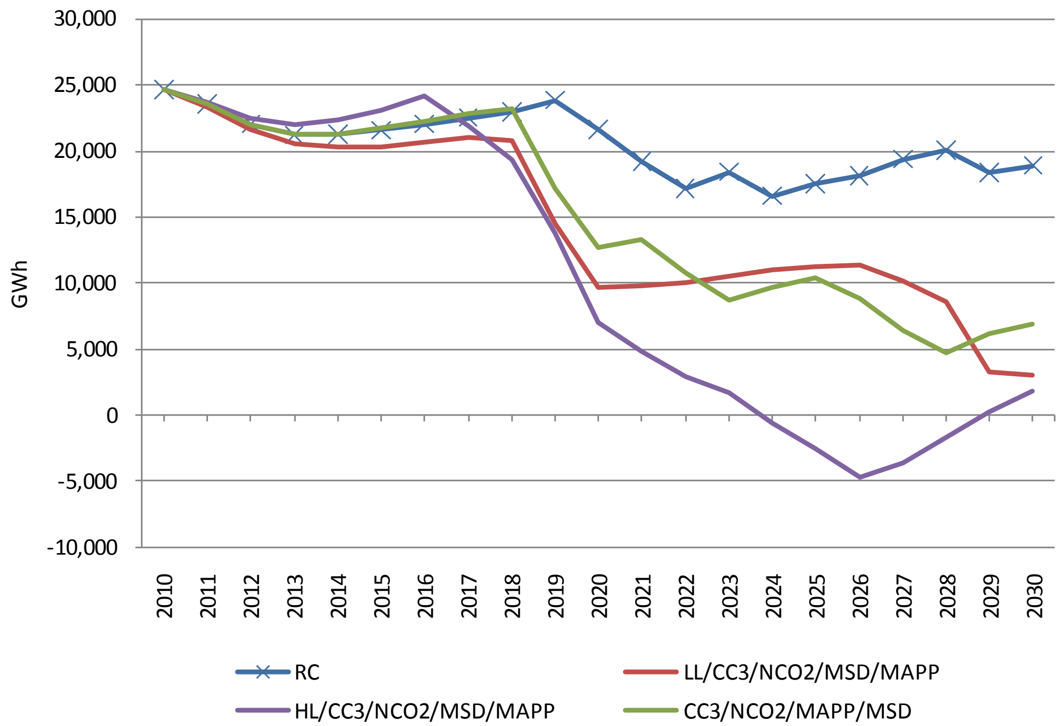


Figure 8.3 PJM-SW Net Imports – High/Low Load and MSD Scenarios



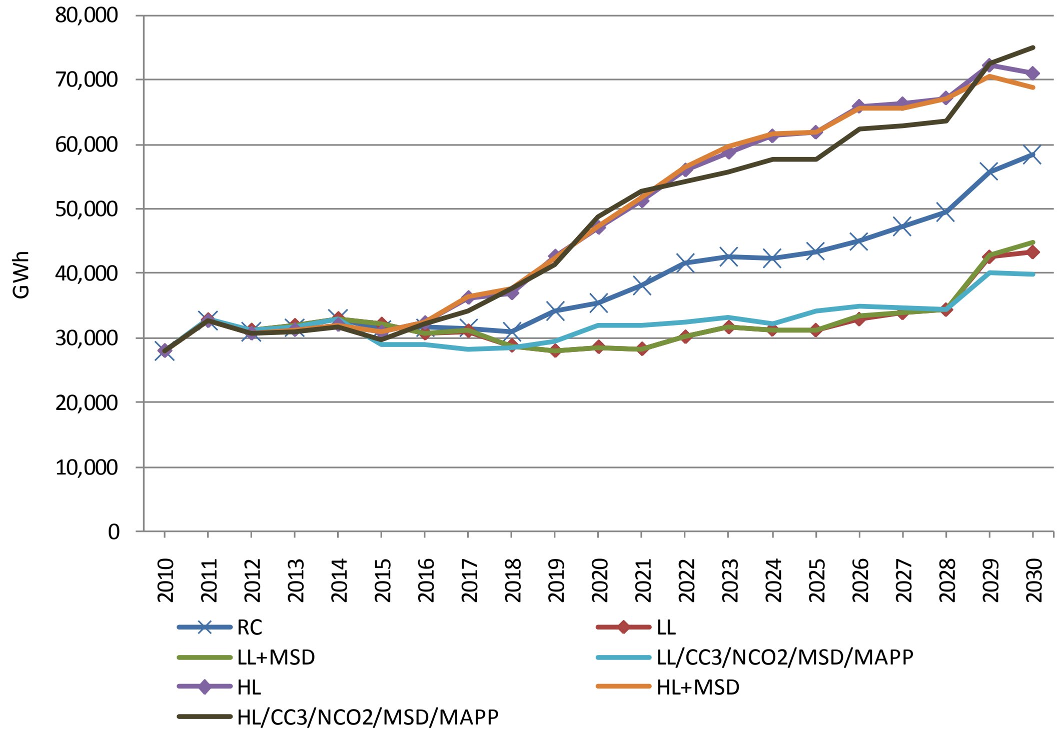
Under the carbon legislation scenarios with both high and low load growth, imports are significantly reduced relative to the LTER Reference Case as new, cleaner generation is built to replace coal-fired generation. In the HL/CC3/NCO2/MSD/MAPP scenario, net imports drop below zero and PJM-SW becomes an 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 – High/Low Load and NCO2 Scenarios



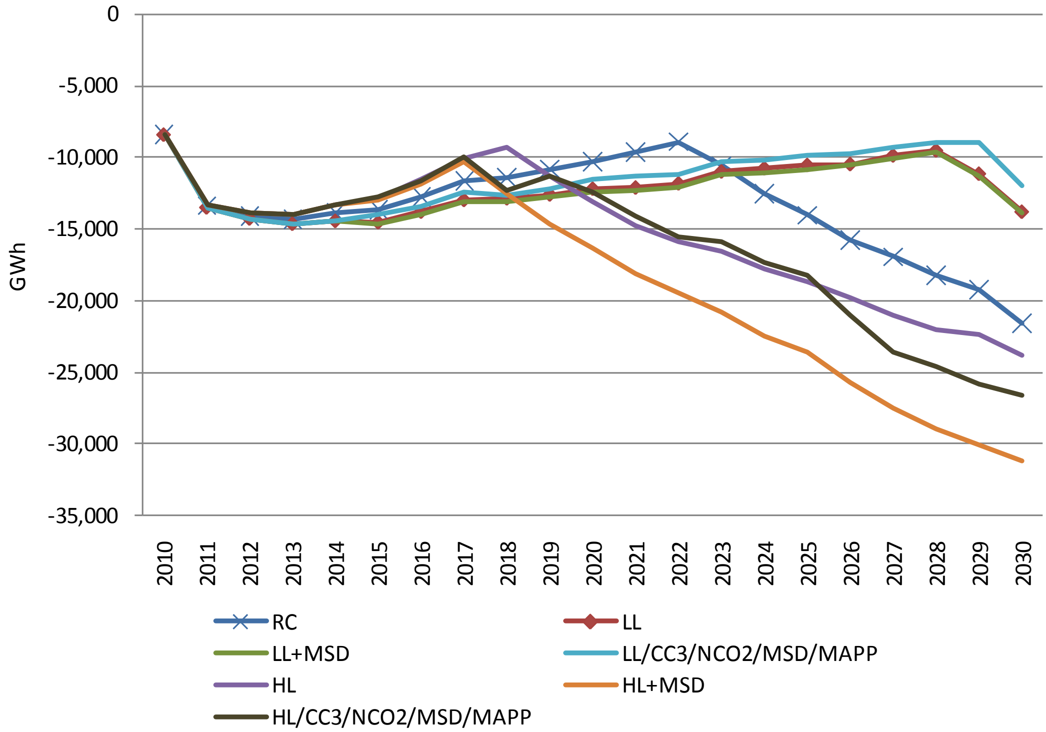
Net imports in PJM-MidE are strongly affected by changes in load but only marginally by infrastructure and carbon prices. Figure 8.5, below, shows net imports for PJM-MidE under all of the load scenarios. PJM-MidE is a higher-priced zone and economics favor imports from areas to the west over construction 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 – High/Low 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 – High/Low Load Scenarios

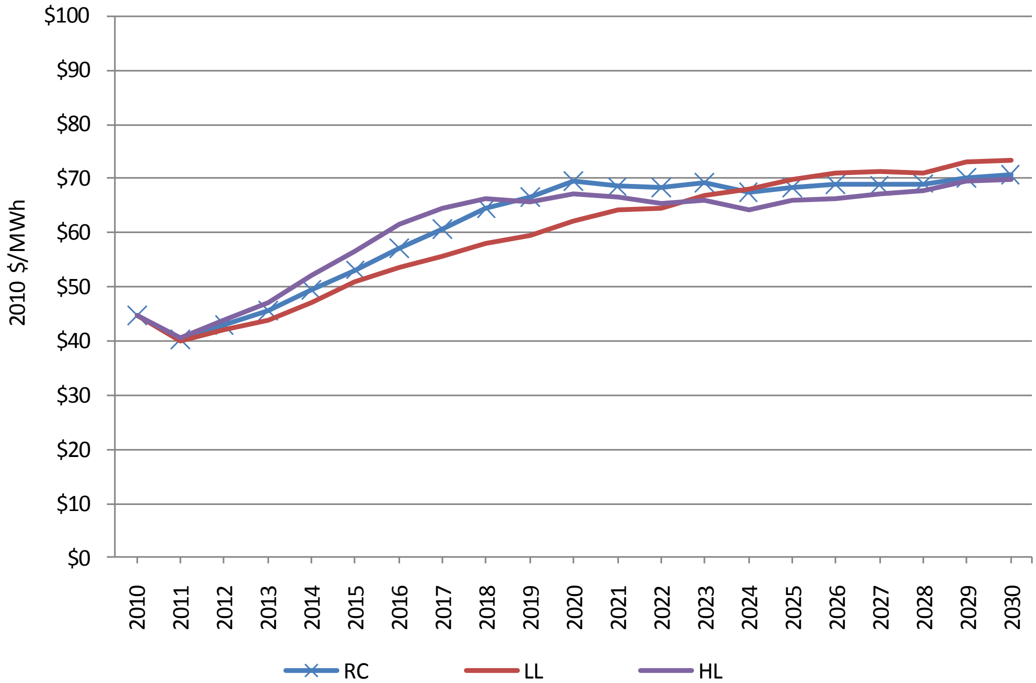


8.4 Energy Prices

In the mid-term, energy prices are significantly affected by changes in load growth. Figure 10.5 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 – High/Low 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 of the study period under the LL/CC3/NCO2/MSD/MAPP scenario 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.

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 8.8 PJM-SW Real All-Hours Energy Prices – High/Low Load and NCO2 Scenarios

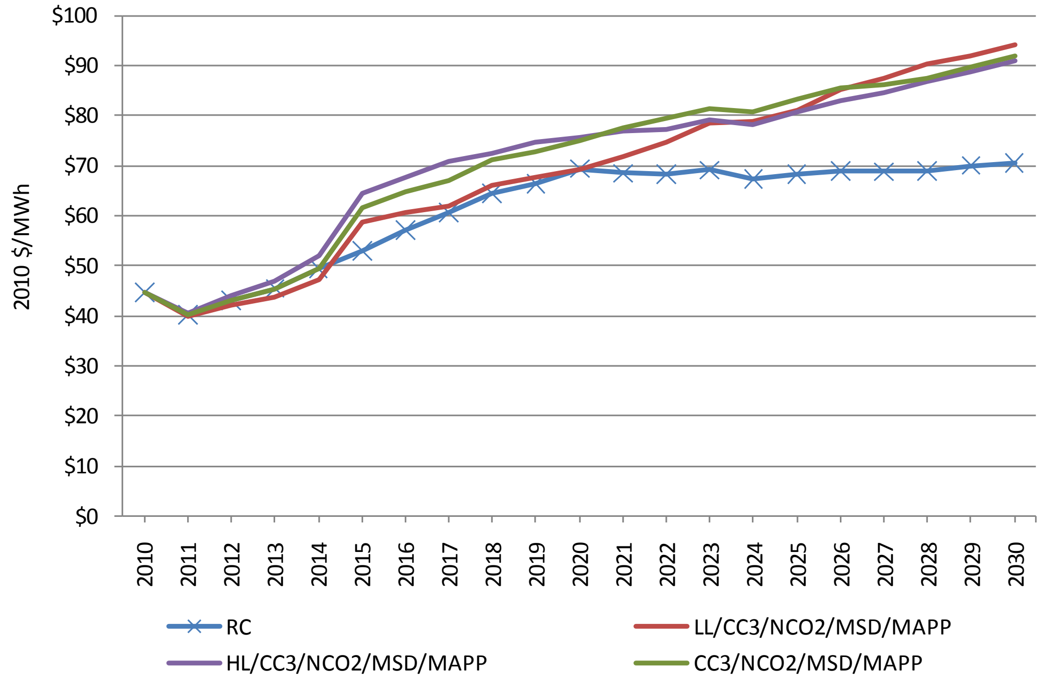


Figure 8.9 PJM-MidE Real All-Hours Energy Prics – High/Low Load and NCO2 Scenarios

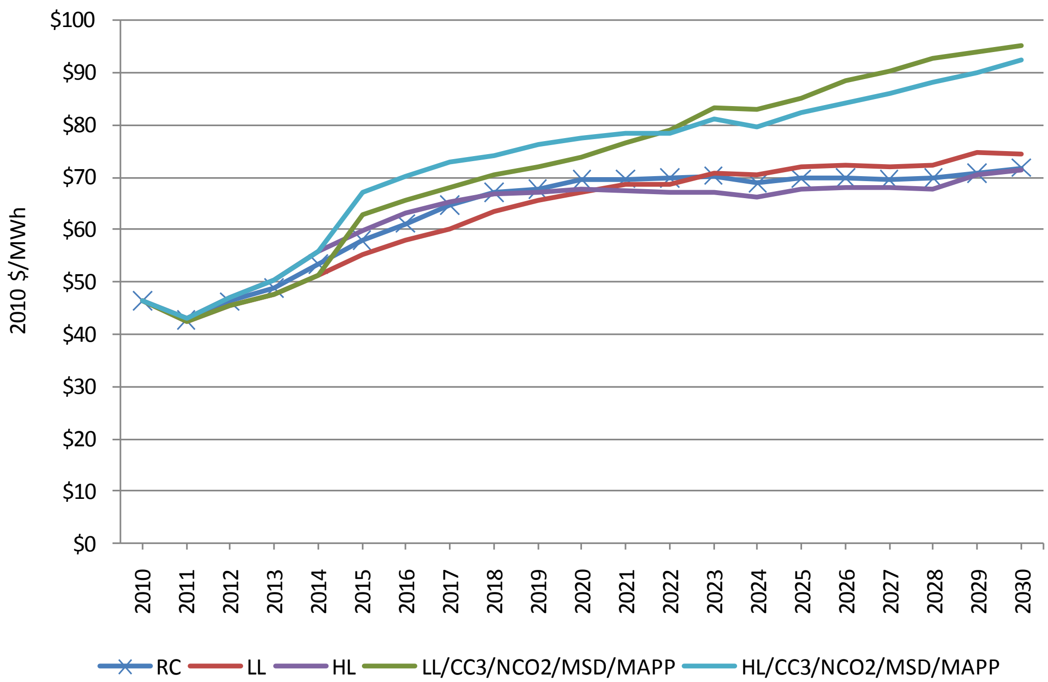
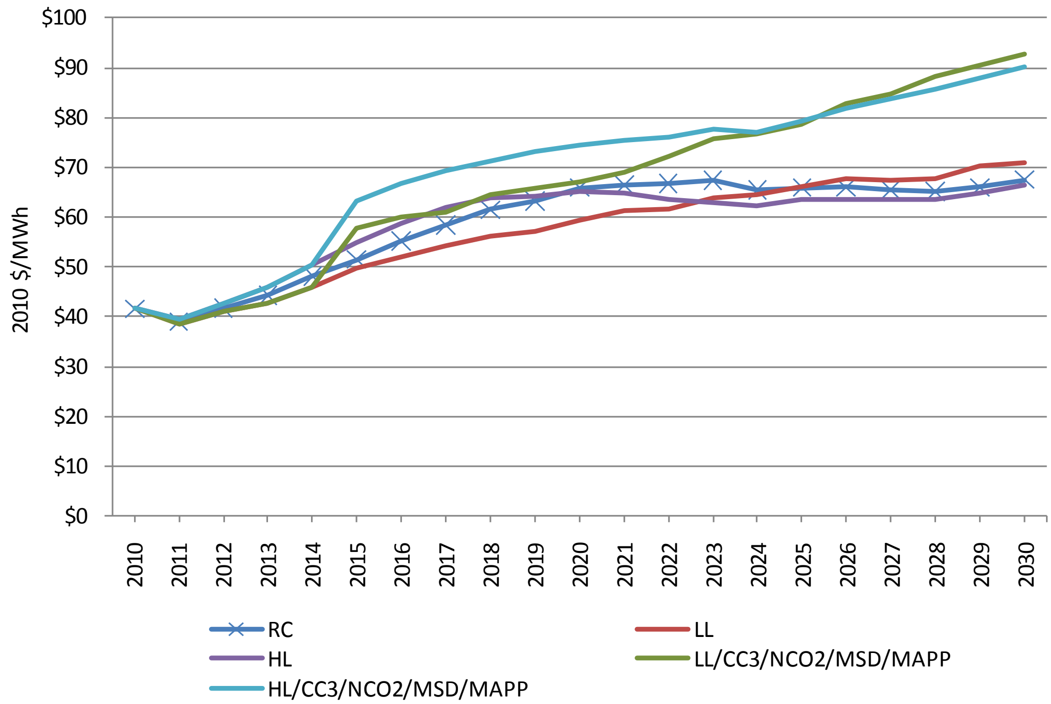


Figure 8.10 PJM-APS Real All-Hours Energy Prices – High/Low Load and NCO2 Scenarios



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.

In PJM-SW, capacity prices converge towards the end of the study period (see Figure 8.11). While this result is expected, convergence is a slower process in PJM-MidE (see Figure 8.12). 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 8.11 PJM-SW Capacity Prices – High/Low Load Scenarios

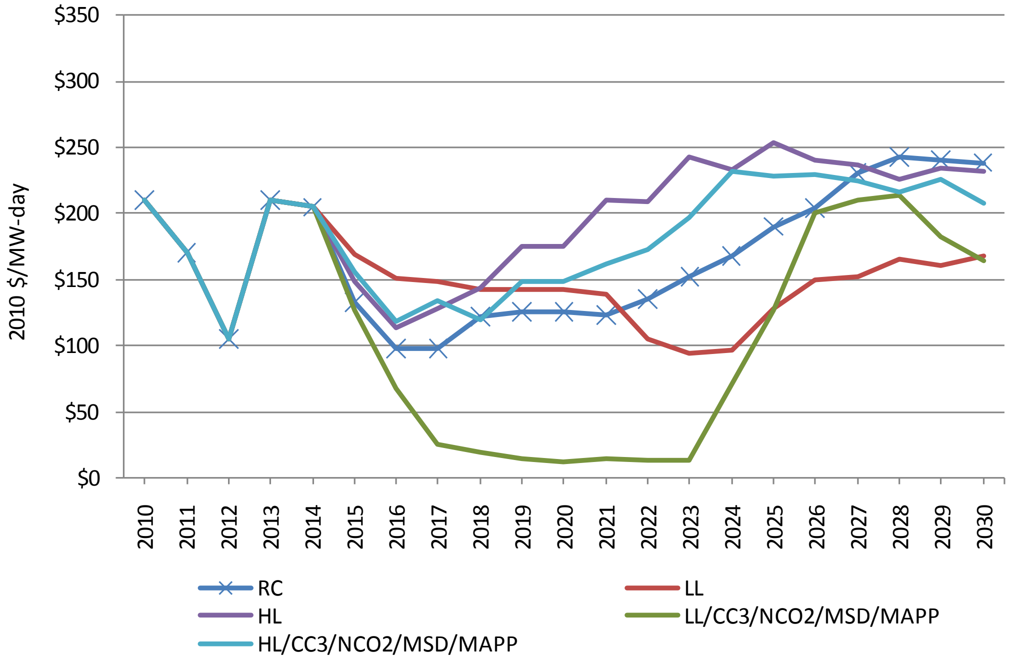
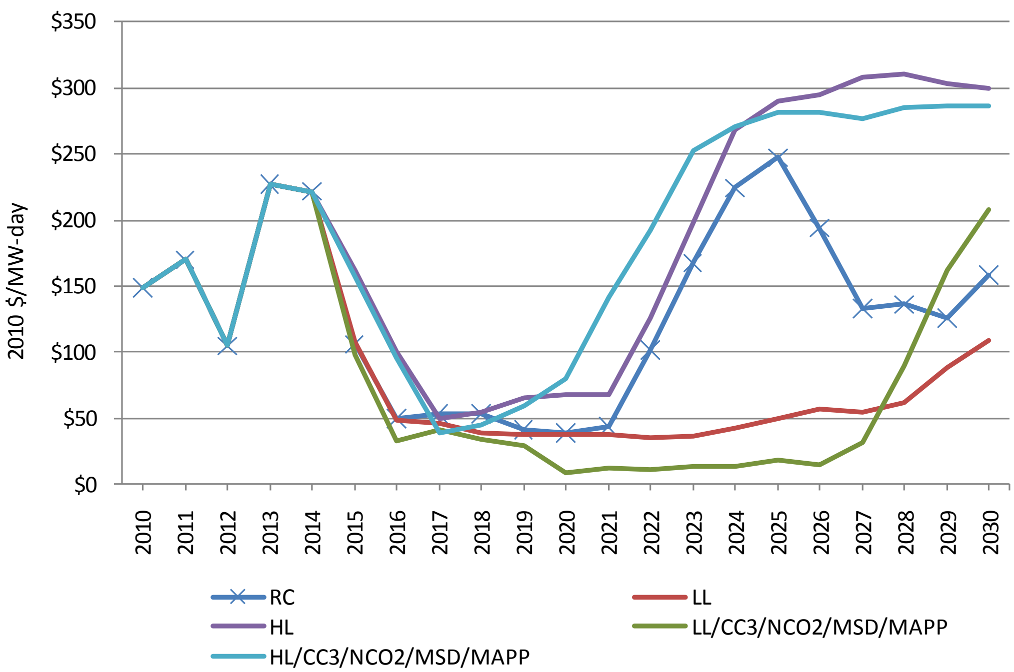
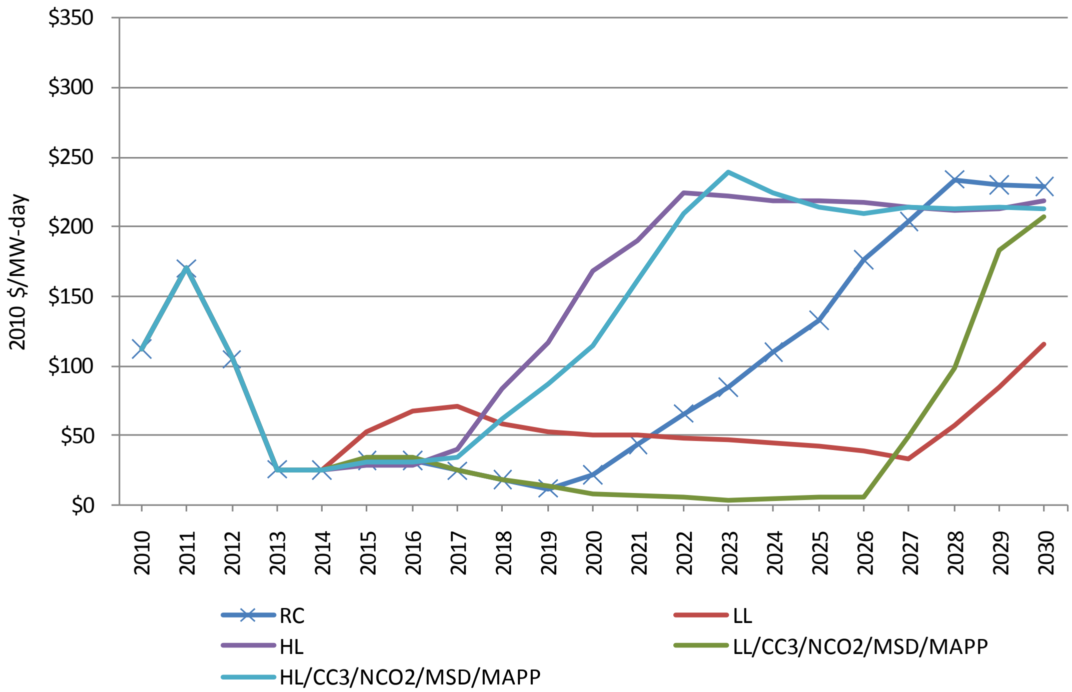


Figure 8.12 PJM-MidE Capacity Prices – High/Low Load Scenarios



In PJM-APS, most of the capacity prices have converged by 2030 (see Figure 8.13), 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 – High/Low Load 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 Plant SO_2 Emissions – High/Low Load Scenarios

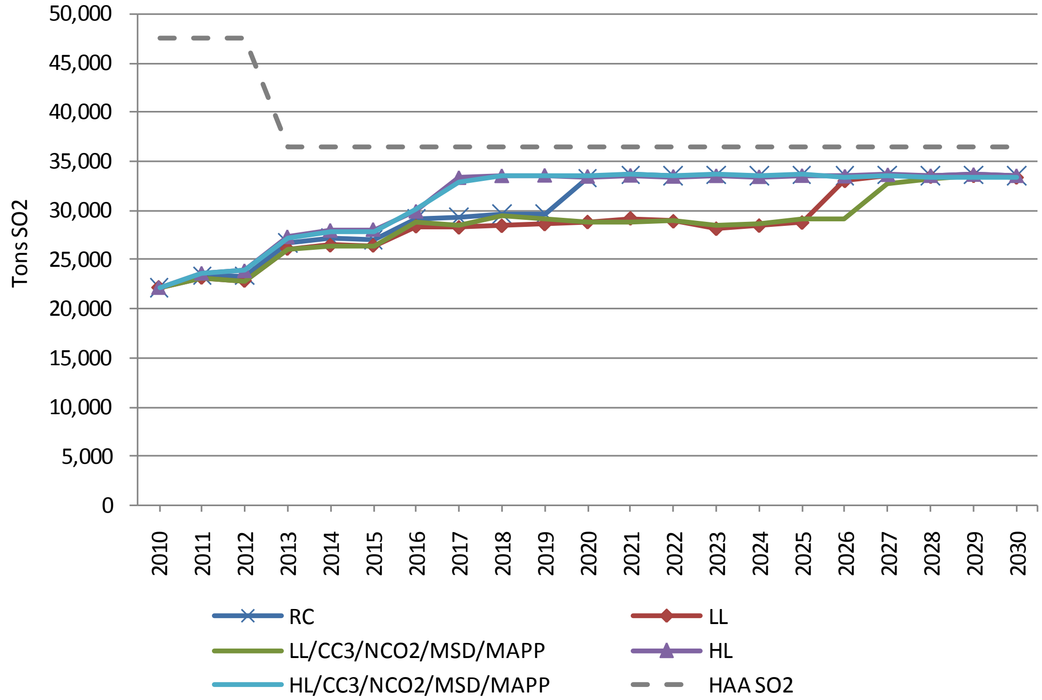


Figure 8.15 Maryland HAA Plant NO_x Emissions – High/Low Load Scenarios

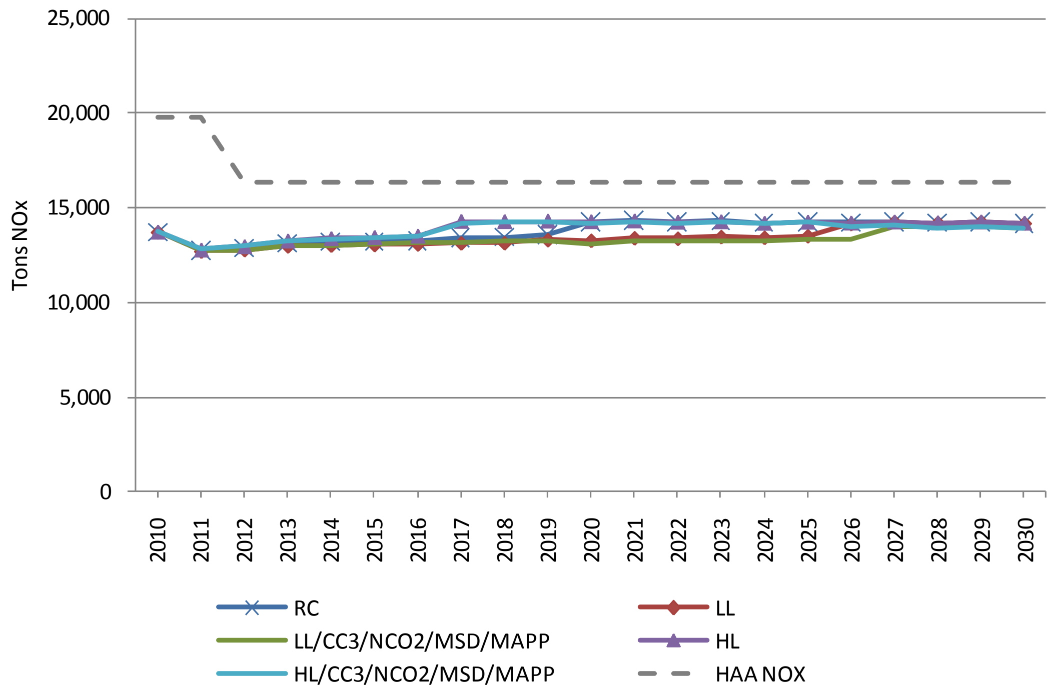


Table 8.3, below, shows the total NO_x emissions for Maryland in 2030. Total NO_x emissions are lower in the low load cases, as fewer new natural gas plants are constructed. Total NO_x emissions in HL+MSD are lower relative to the other high load cases, as Maryland imports more energy from PJM-APS instead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

Table 8.3 Total Maryland NO_x Emissions From Electric Generation in 2030 – High/Low Load Scenarios

Scenario	Total NOx Emissions (tons)
RC	17,223
LL	16,882
LL+MSD	16,817
LL/CC3/NCO2/MSD/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 Electric Generation CO_2 Emissions – High/Low Load and MSD Scenarios[36]

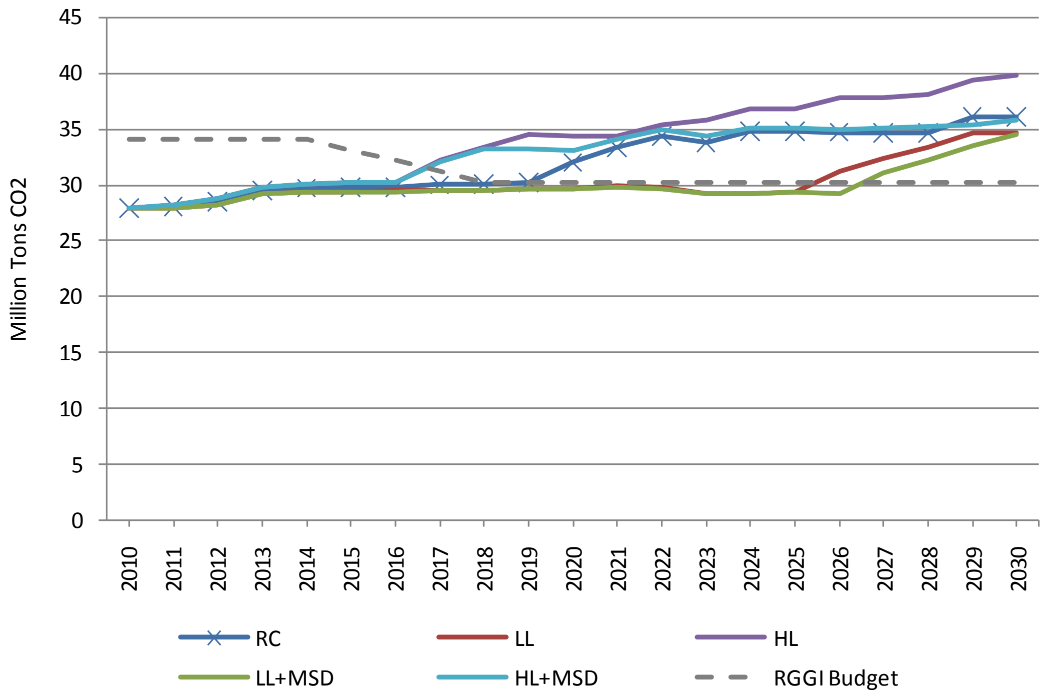


Figure 8.17 shows the total Maryland CO_2 emissions for the high and low load scenarios with a carbon price. Total in-State CO_2 emissions begin to decrease after 2025 due to retrofit de-rates and reduced use of coal-fired facilities. The LL and LL+MSD scenarios are below the Maryland Regional Greenhouse 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.

Table 8.4 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.

[36] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

Figure 8.17 Maryland Electric Generation CO_2 Emissions – High/Low Load and NCO2 Scenarios[37]

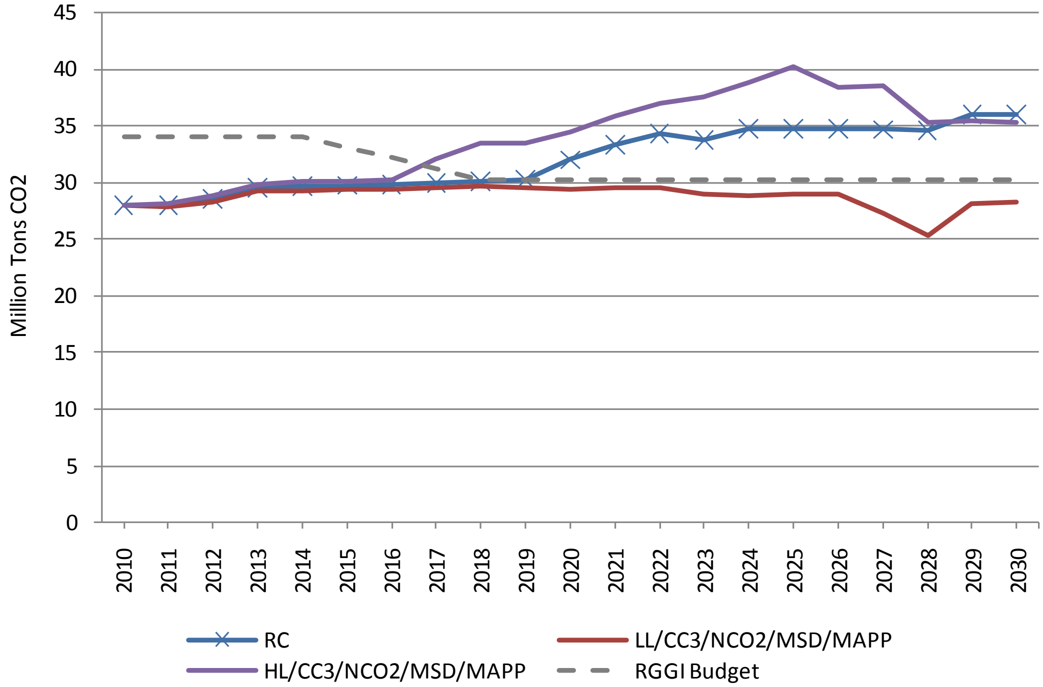


Table 8.4 Fuel Use for Electricity Generation in Maryland in 2030 – High/Low Load Scenarios

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

[37] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

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 15,000 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	On-shore 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

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 capacity 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

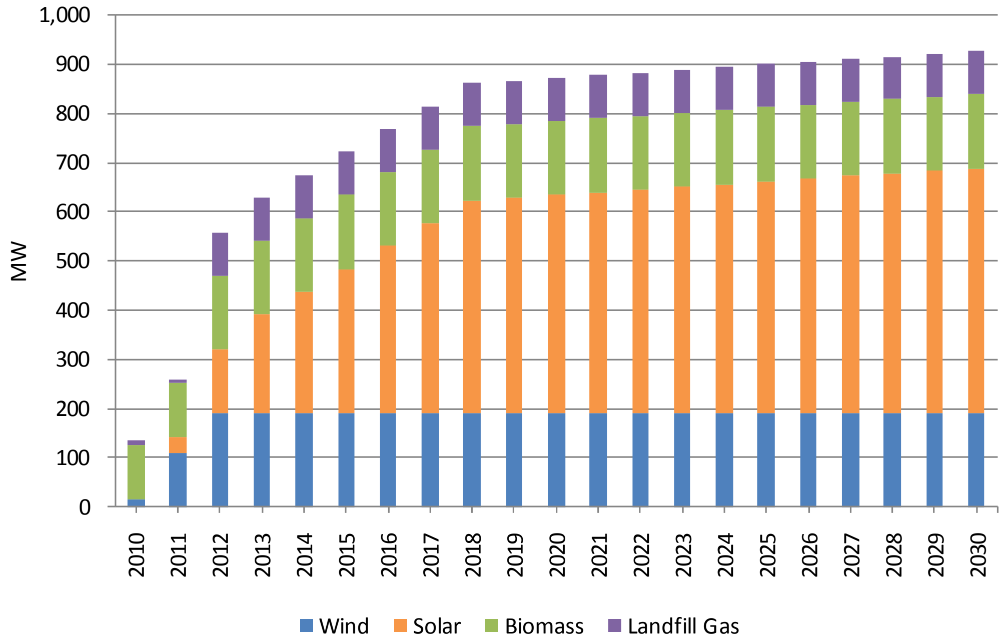
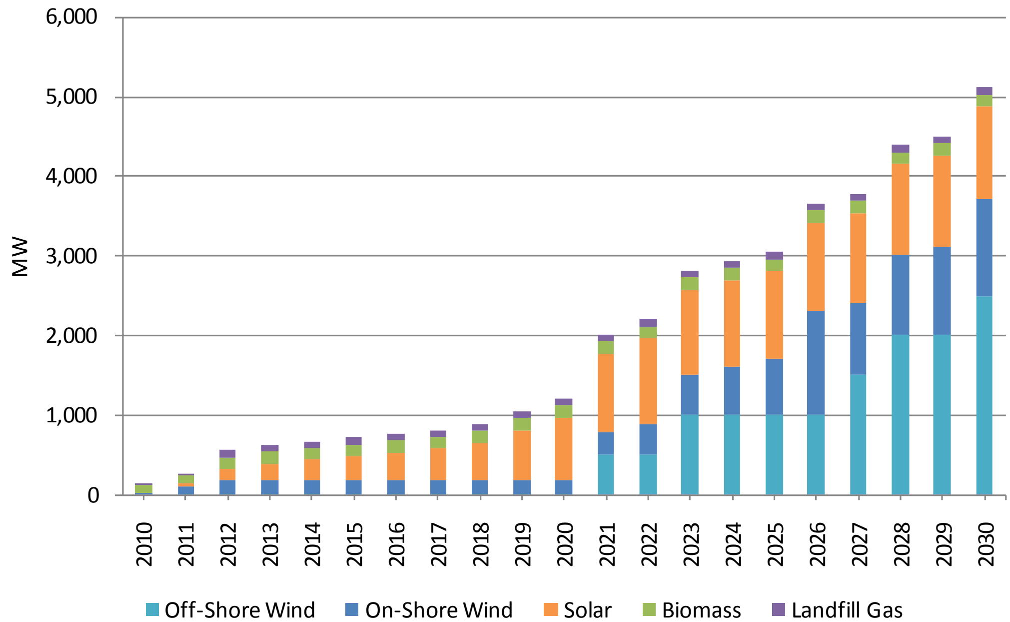


Figure 9.2 High Renewables Scenarios: Total RPS Capacity Additions in Maryland



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

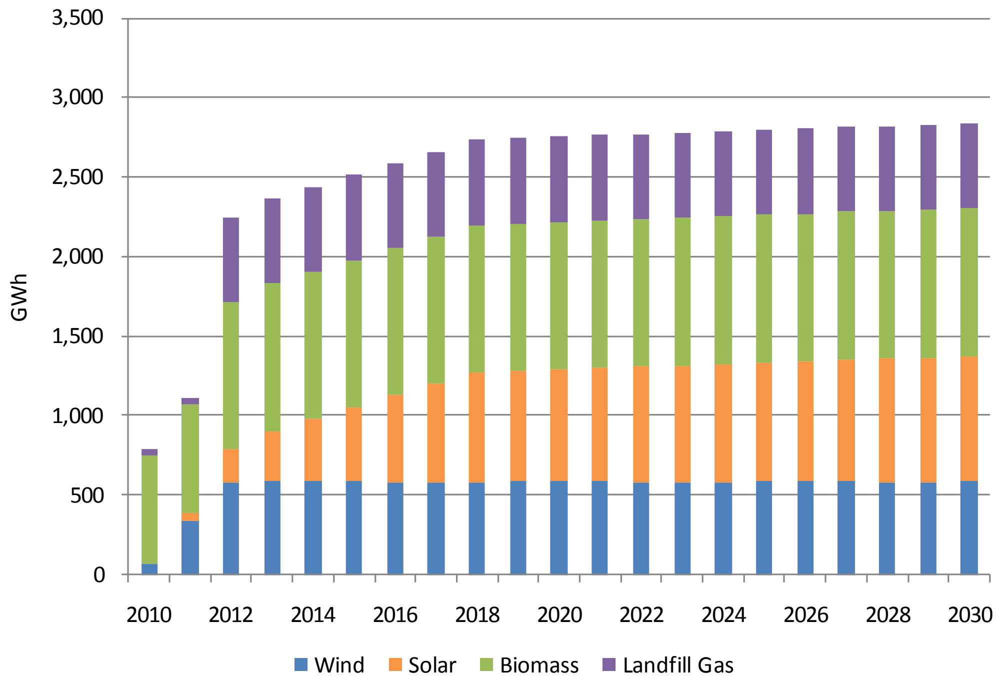
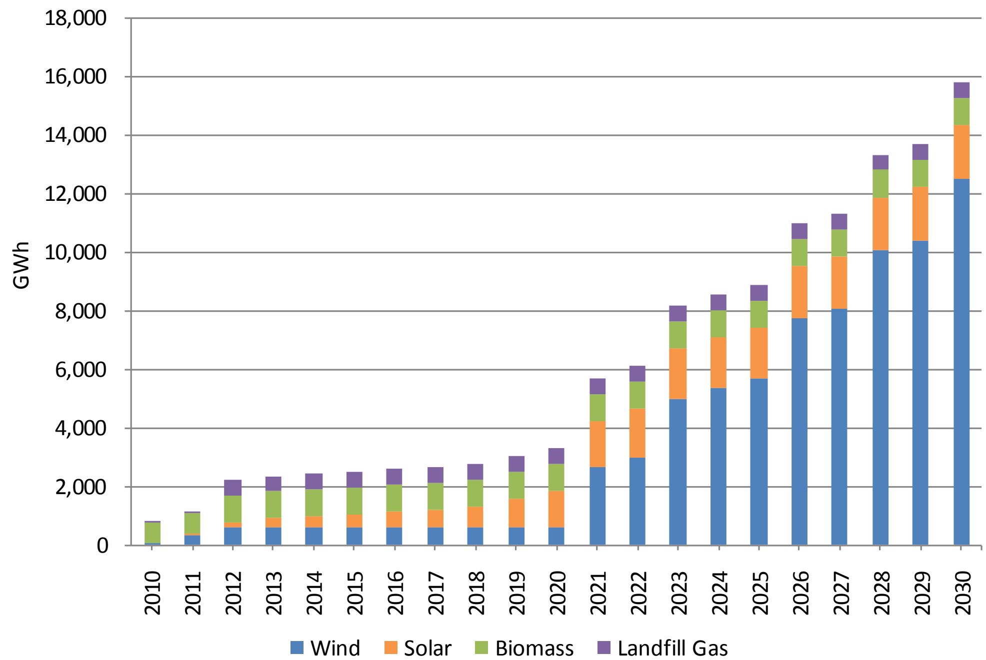


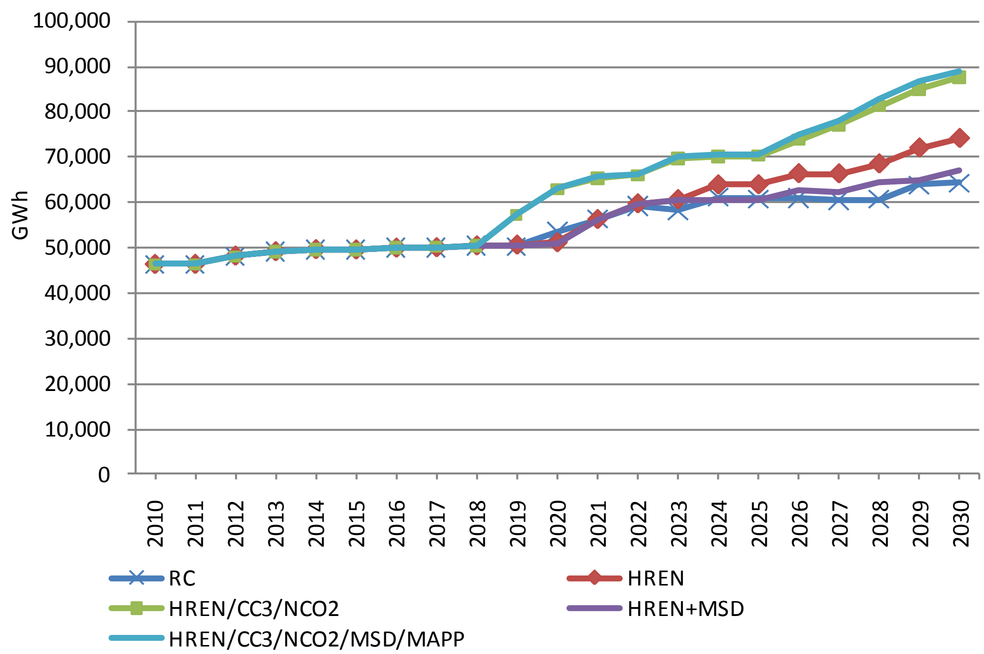
Figure 9.4 High Renewables Scenarios: Renewable Generation in Maryland



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 - 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 offset 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.

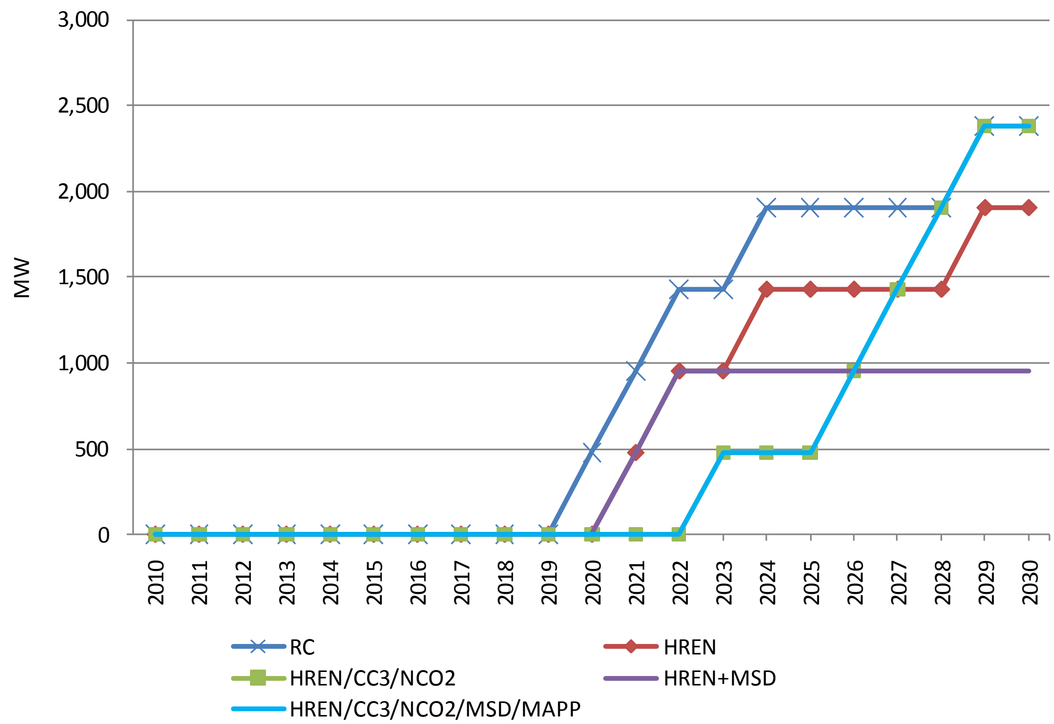
Total generation increases more substantially in the High Renewables scenario that includes Calvert Cliffs 3 and national carbon legislation ("HREN/CC3/NCO2"), and the High renewables scenario that includes Calvert Cliffs 3, national carbon legislation, the Mt. Storm to

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 an increase in net imports into PJM-SW from PJM-APS.

Figure 9.6 PJM-SW Natural Gas Capacity Additions – High Renewables Scenarios

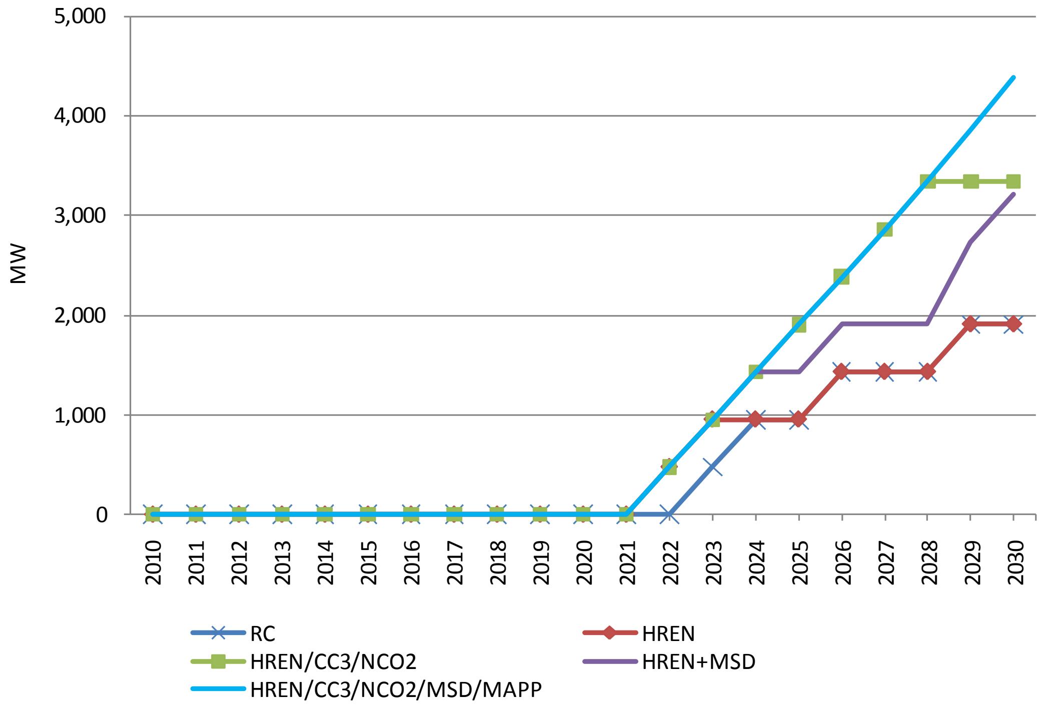


Under the scenarios that include Calvert Cliffs 3, the need for new natural gas capacity is delayed by three years to 2022 compared to the LTER Reference Case. However, projected natural gas capacity additions ultimately converge to the LTER Reference Case by 2028 as additional natural gas capacity is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

Figure 9.7 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

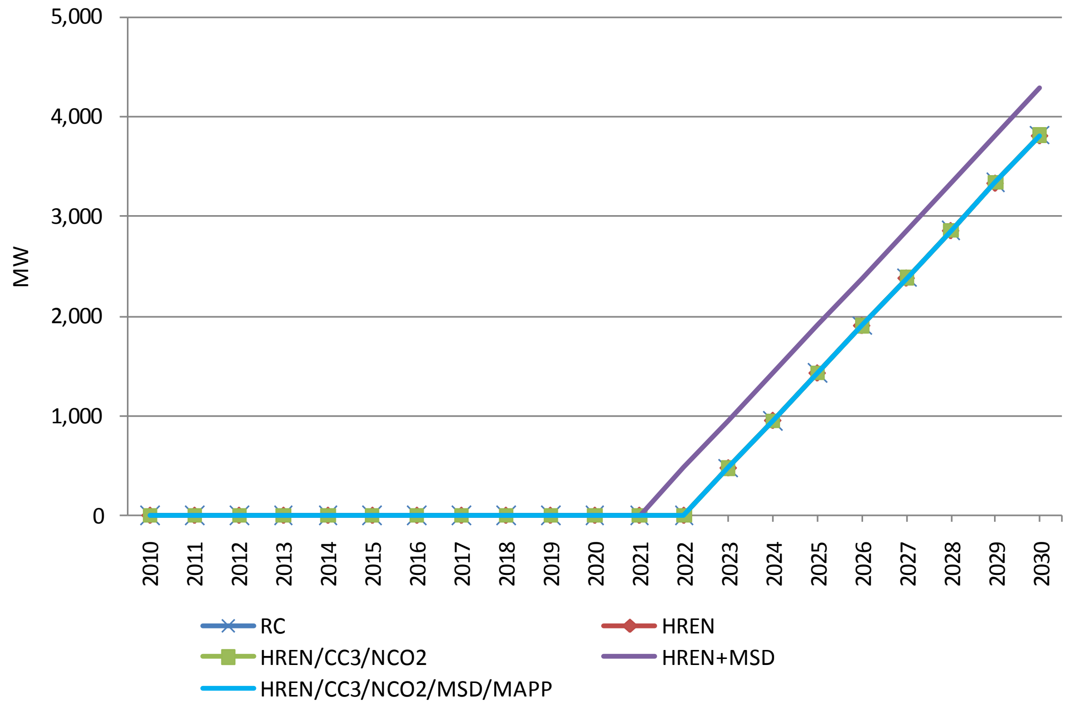
Reference Case, as opportunities to import energy are reduced due to the delayed natural gas builds in PJM-SW. As in PJM-SW, under the scenarios with national carbon legislation, PJM-MidE builds additional capacity to replace coal generation lost due to retirements and retrofits. In the HREN+MSD scenario, 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 – High Renewables Scenarios



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).

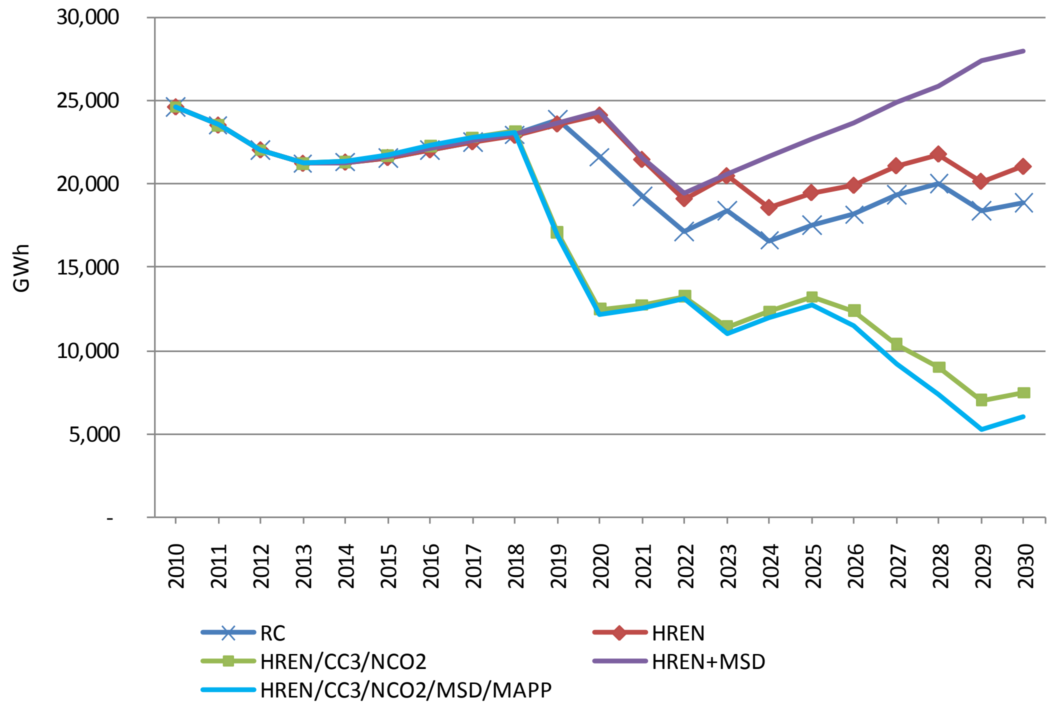
Figure 9.8 PJM-APS Natural Gas Capacity Additions – High Renewables Scenarios



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 combined cycle natural gas 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 – High Renewables Scenarios



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.

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 9.10 PJM-MidE Net Imports – High Renewables Scenarios

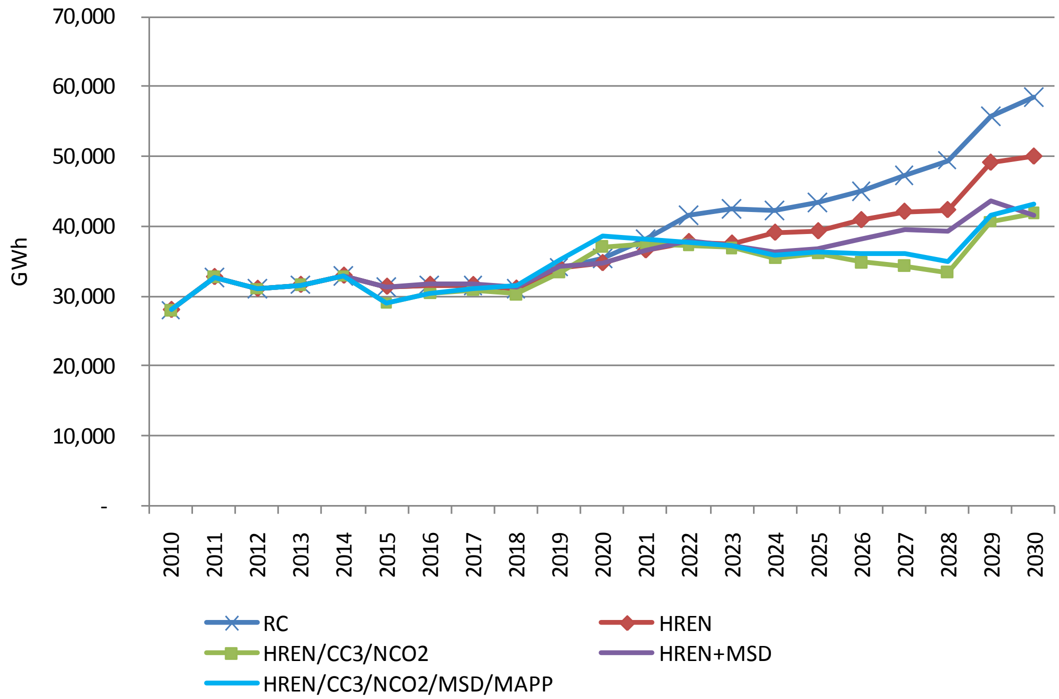
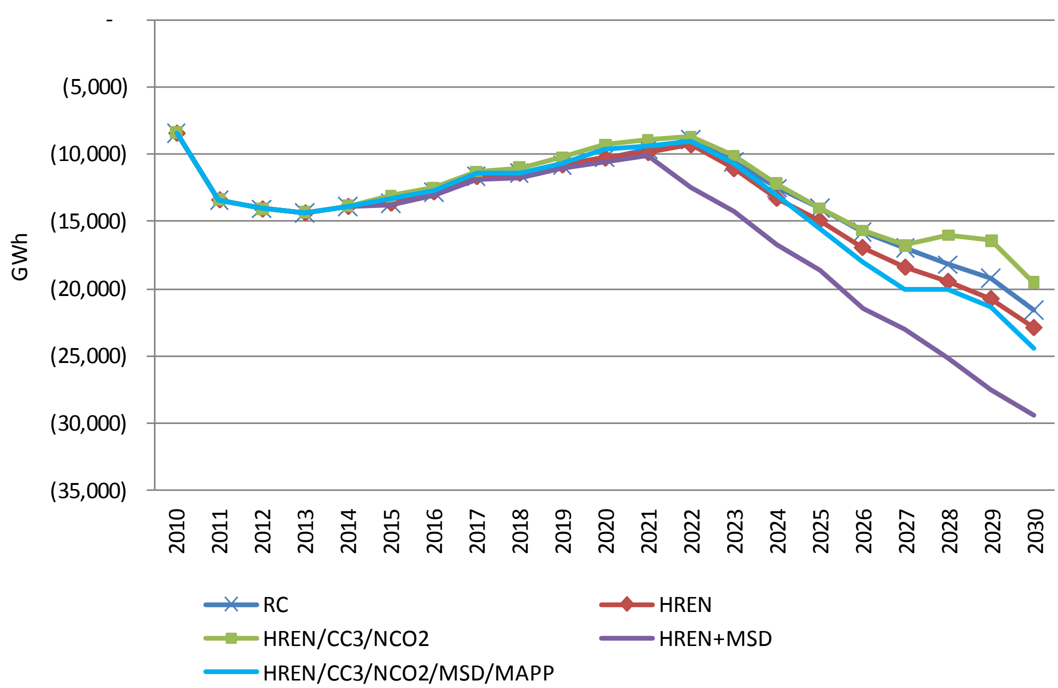


Figure 9.11 PJM-APS Net Imports – High Renewables Scenarios



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 – High Renewables Scenarios

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 is 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.

Figure 9.12 Coal Use for Electricity Generation in Maryland – High Renewables Scenarios

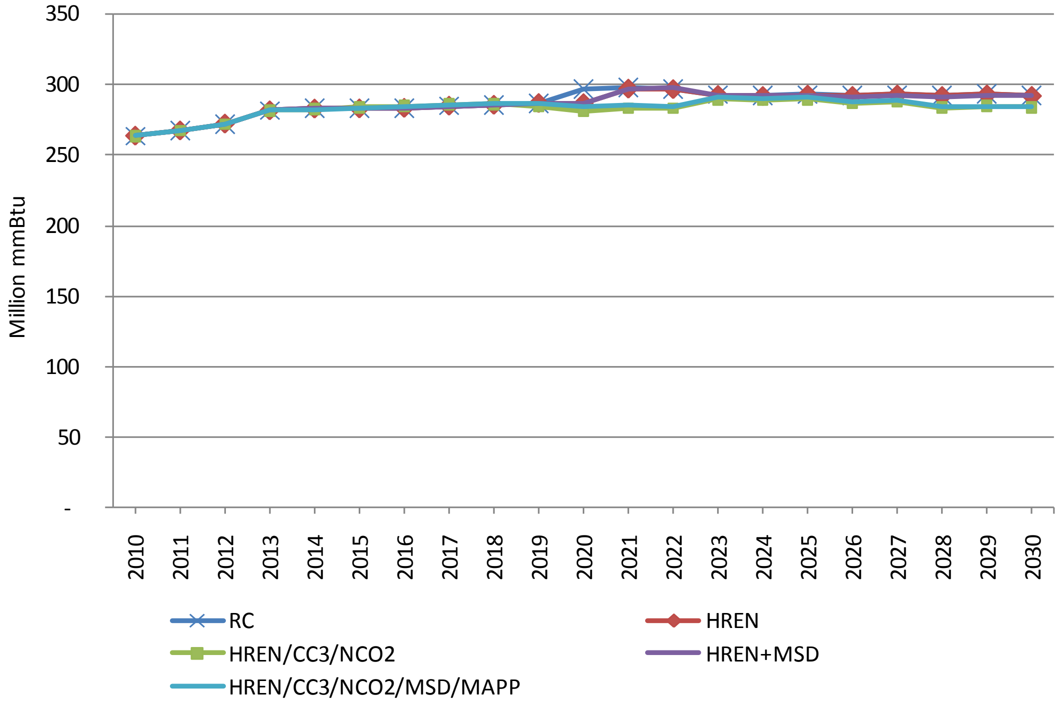
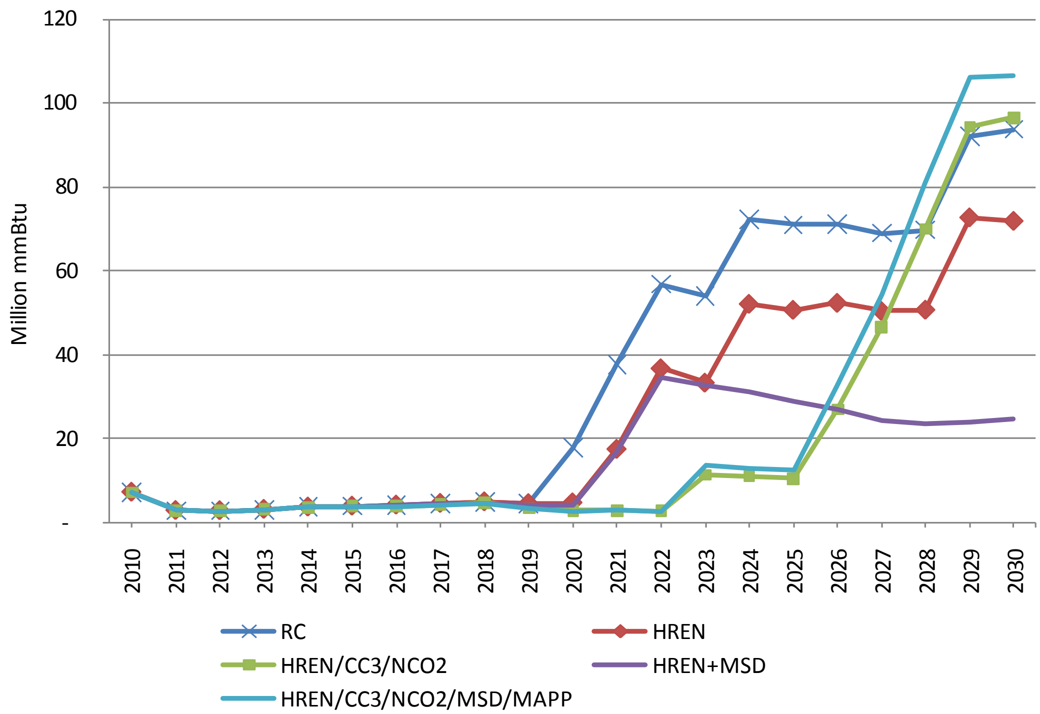


Figure 9.13 Natural Gas Use for Electricity Generation in Maryland – High Renewables Scenarios



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 – High Renewables Scenarios

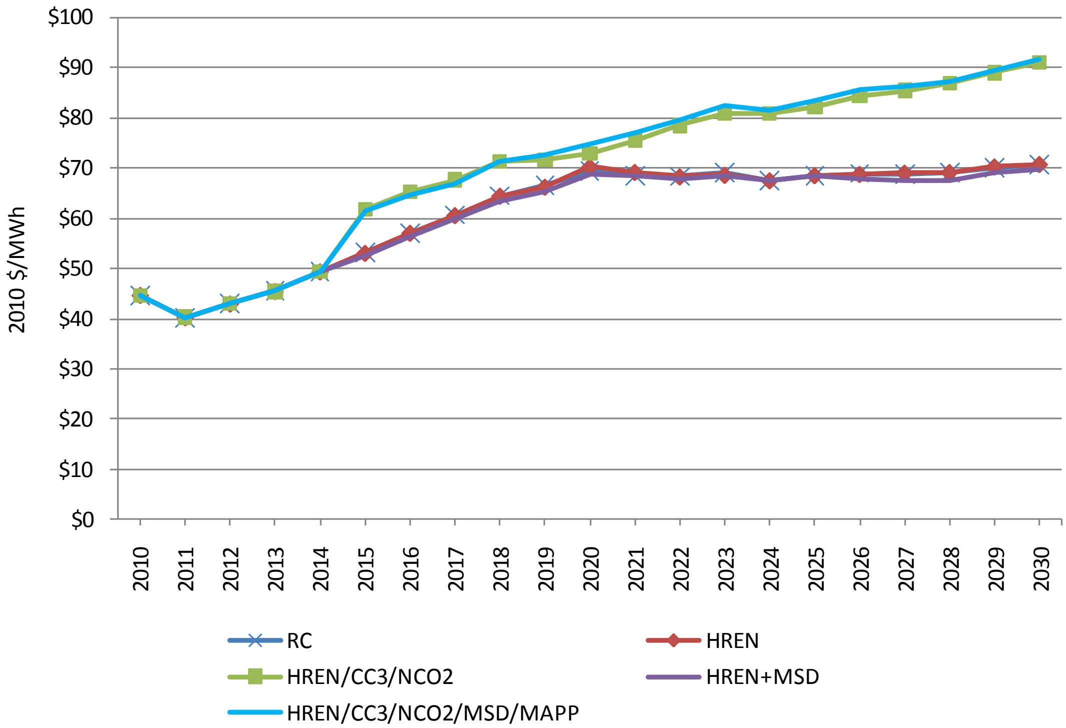


Figure 9.15 PJM-MidE Real All-Hours Energy Price – High Renewables Scenarios

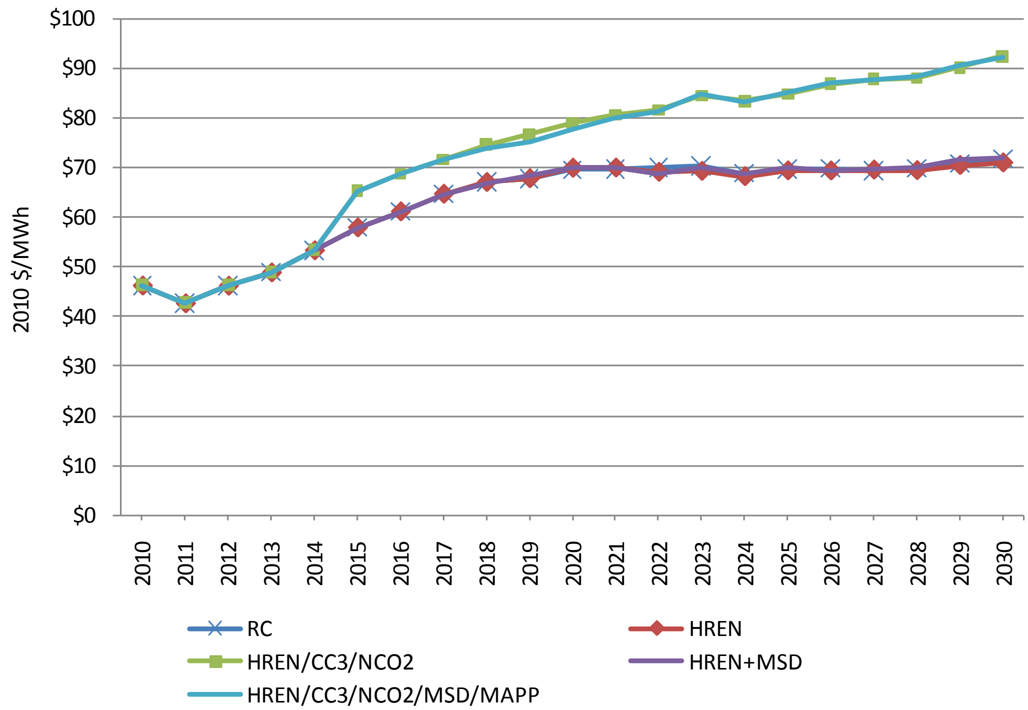
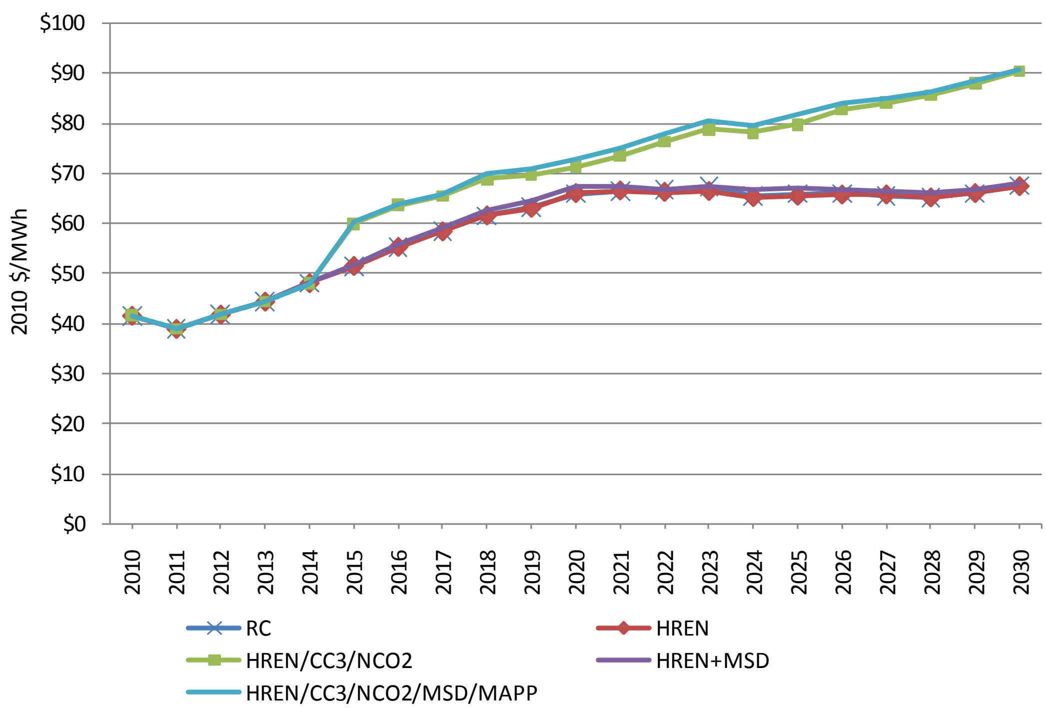


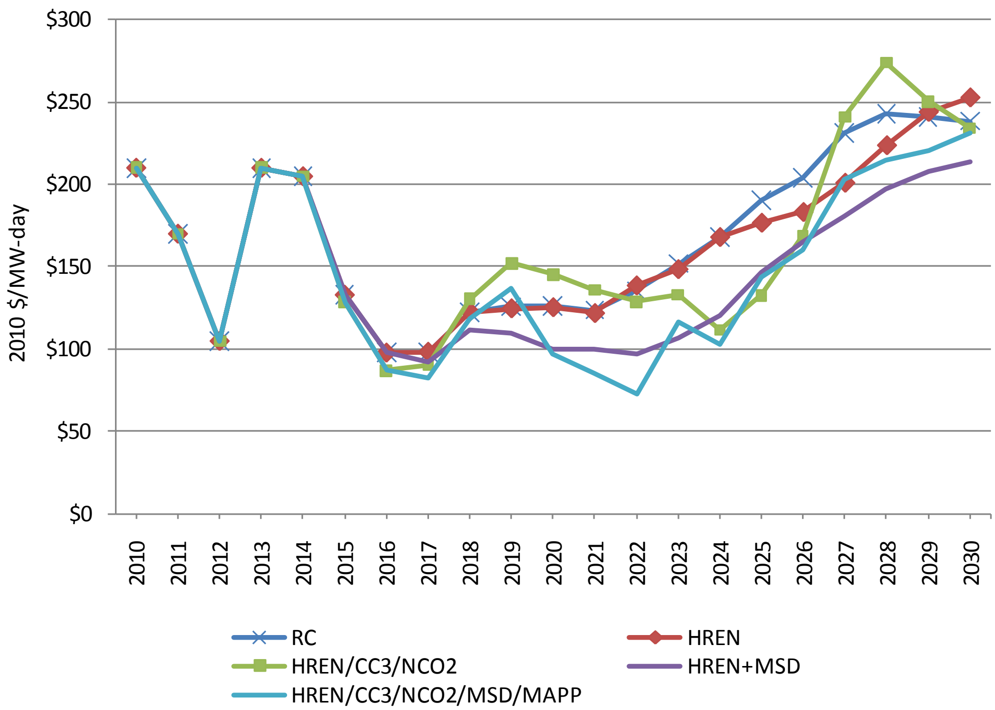
Figure 9.16 PJM-APS Real All-Hours Energy Price – High Renewables Scenarios



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 – High Renewables Scenarios

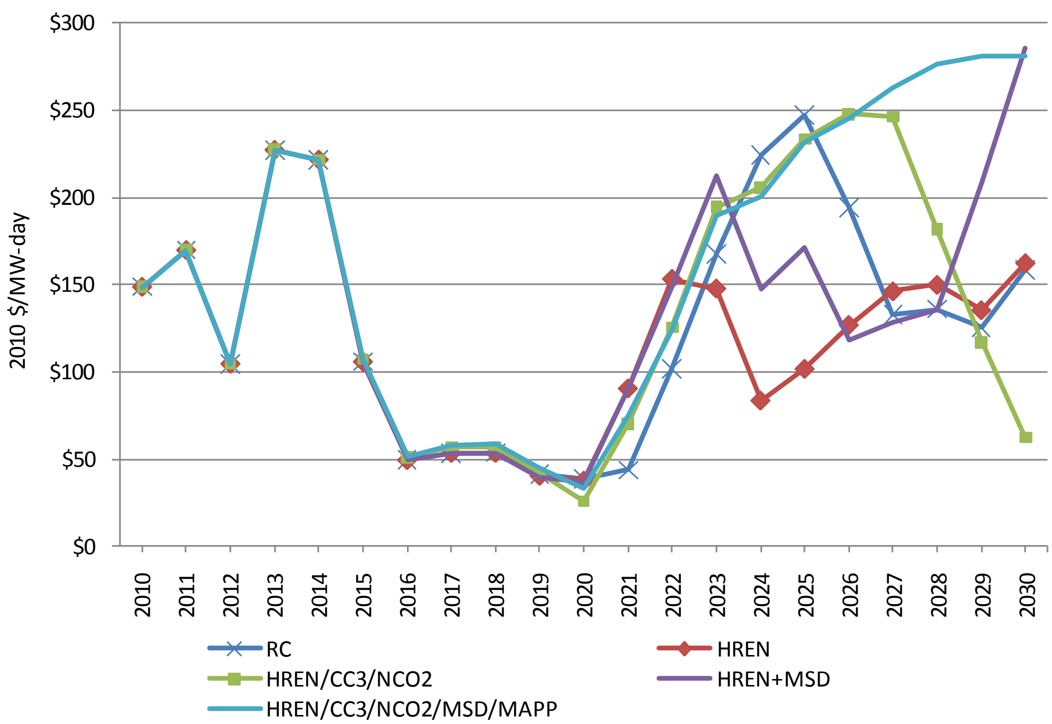


Both of the High Renewables scenarios that include construction of the Mt. Storm to Doubs transmission line are characterized by PJM-SW capacity prices below those shown for the LTER Reference Case. This difference is largely attributable to the increased import capability (from PJM-APS) accommodated 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.

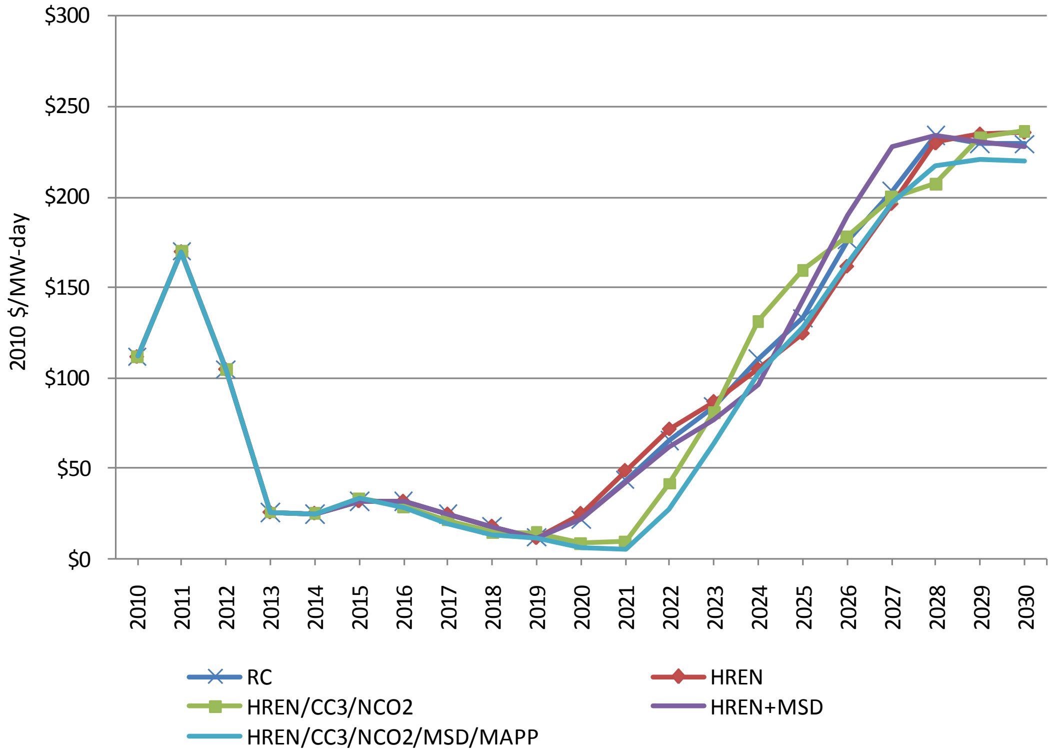
The same basic relationship between the PJM-SW capacity prices for the LTER Reference Case and the HREN scenario exists for PJM-MidE (see Figure 9.18 below). The HREN scenario exhibits lower capacity prices in the mid-2020s as a result of higher renewable build-out, but for the earlier years of the study 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 – High Renewables Scenarios



With respect to capacity prices in PJM-APS, shown in Figure 9.19 below, there are 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.

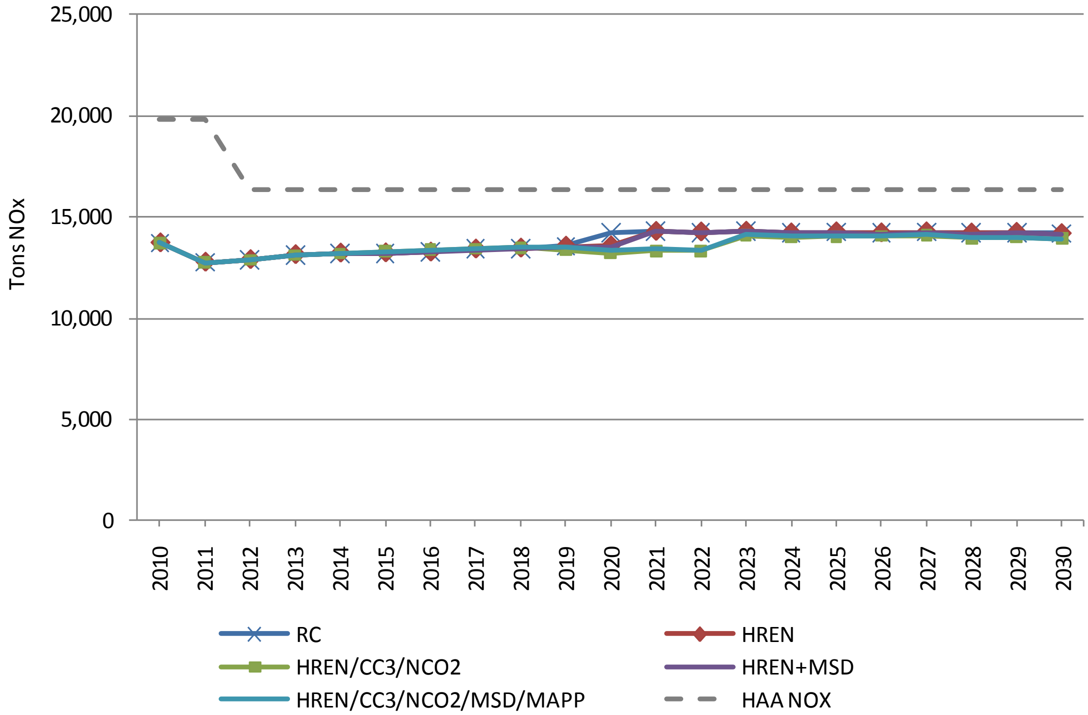
Figure 9.19 PJM-APS Capacity Prices – High Renewables Scenarios



9.8 Emissions

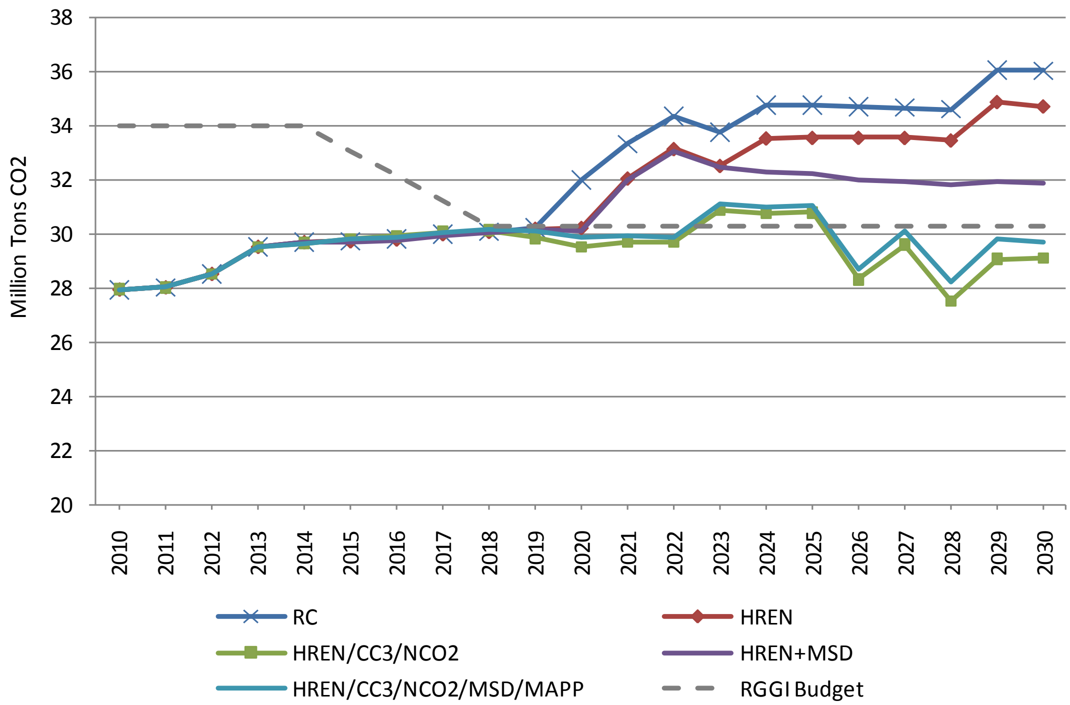
Because the High Renewables scenario delays the addition of a new natural gas plant by one year relative to the LTER Reference Case, NO_x emissions in the HREN scenario are the same as the LTER Reference Case for all years except 2020, where a slight difference exists due to the timing of the build-out. 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 Maryland HAA Plant NO_x Emissions – High Renewables Scenarios



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 Electric Generation CO_2 Emissions – High Renewables Scenarios[38]



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

[38] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

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.[39] 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.

[39] 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 – EE Scenarios

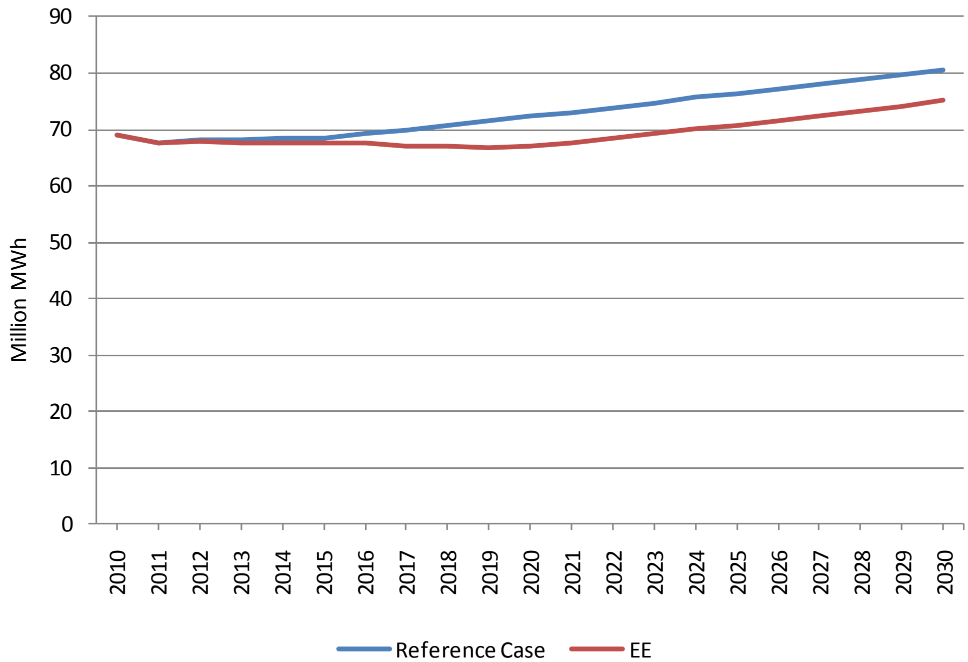
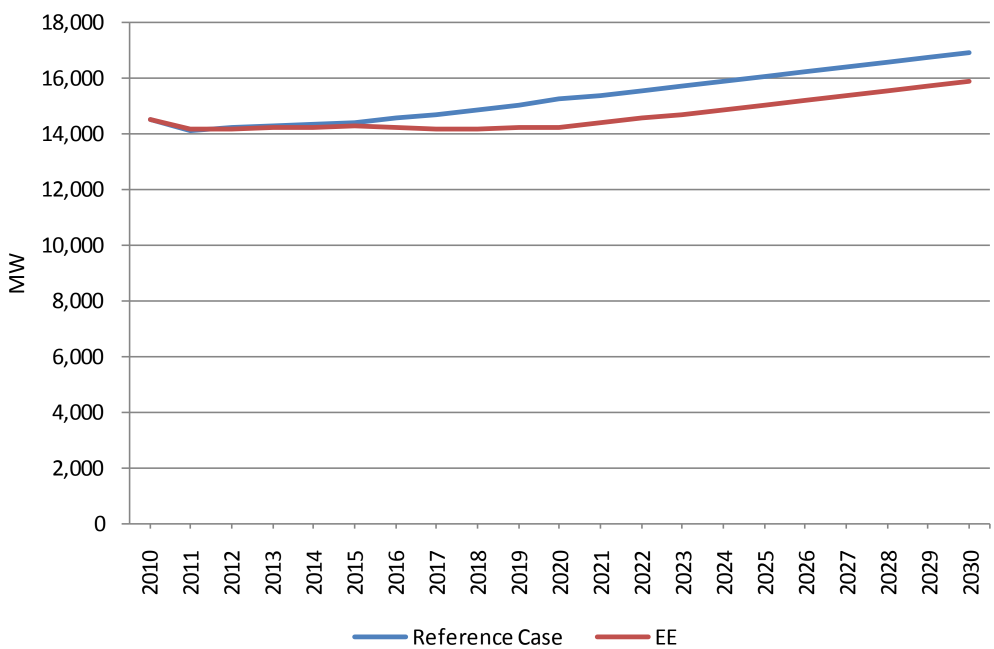


Figure 10.2 PJM-SW Peak Demand – EE Scenarios

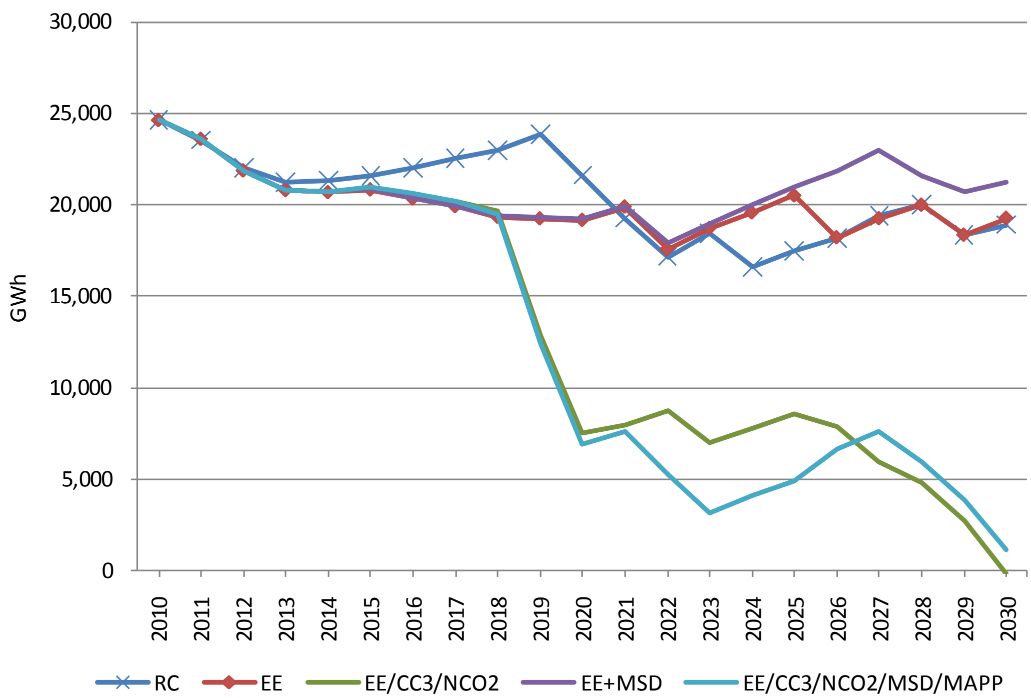


As seen in both Figure 10.1 and Figure 10.2, the total reduction in energy consumption and peak demand associated with more aggressive energy efficiency and conservation programs in Maryland is relatively modest compared to total energy consumption and peak demand in PJM-SW. Similar graphs for PJM-APS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

10.2 Net Imports

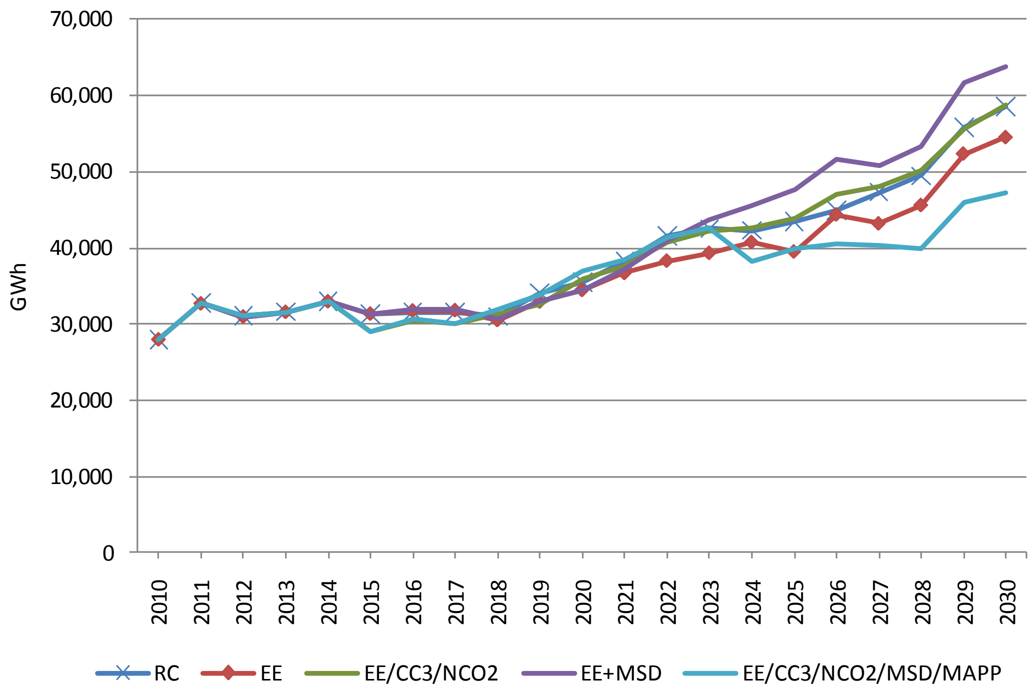
The increased energy efficiency in Maryland reduces load but has little effect on net imports into PJM-SW. Figure 10.3, below, shows the net imports into PJM-SW under the EE scenarios. As Figure 10.3 shows, there is little difference in net imports under the LTER Reference Case and the EE scenario. Net 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 – EE Scenarios



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 - EE 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 scenario, 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 – EE Scenarios (MW)

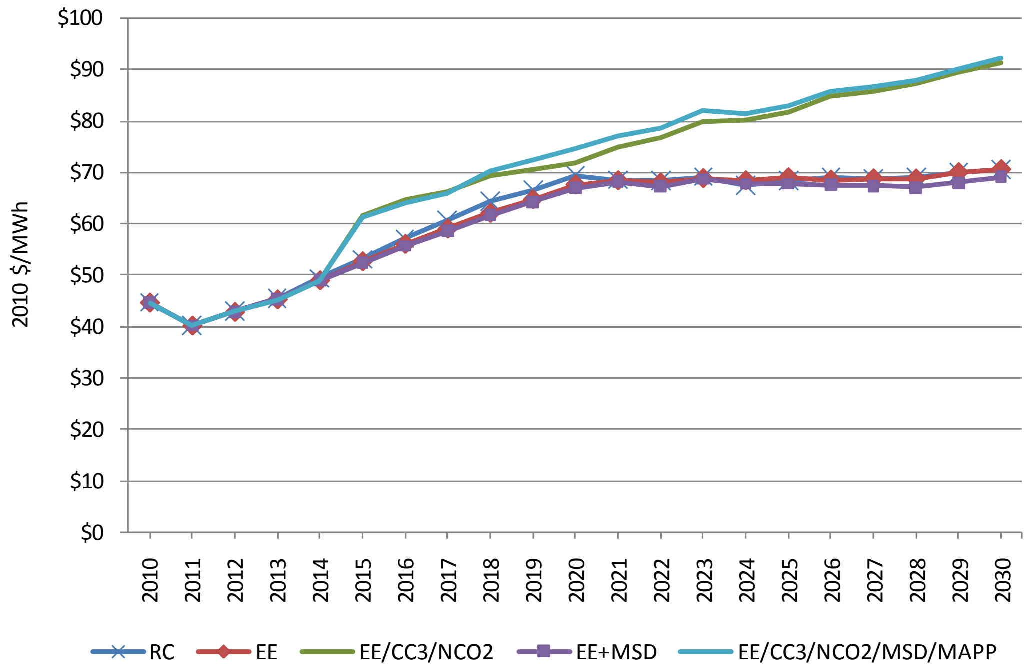
Scenario	PJM-SW	PJM-MidE	PJM-APS	PJM Total
RC	2,385	1,908	3,816	30,101
EE	1,431	2,385	3,816	28,193
EE+MSD	1,431	477	4,770	27,845
MSD	1,431	3,816	4,770	30,145
EE/CC3/NCO2	2,862	1,431	3,816	33,971
EE/CC3/NCO2/MSD/MAPP	2,385	4,293	3,816	33,753

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, 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.

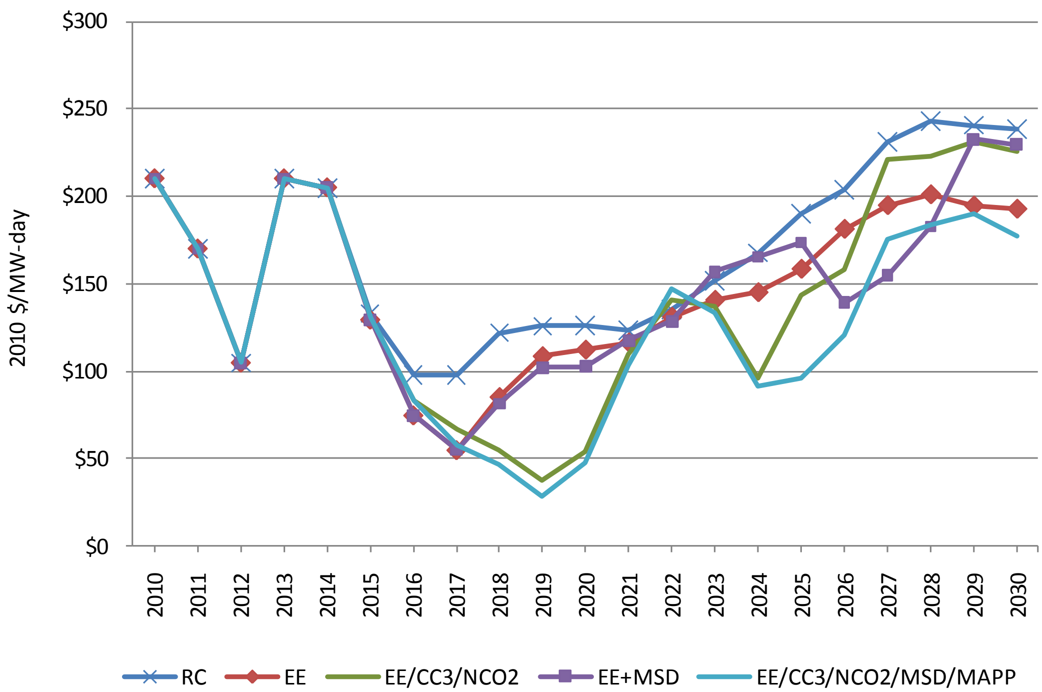
Figure 10.5 PJM-SW Real All-Hours Energy Price – EE Scenarios



10.5 Capacity Prices

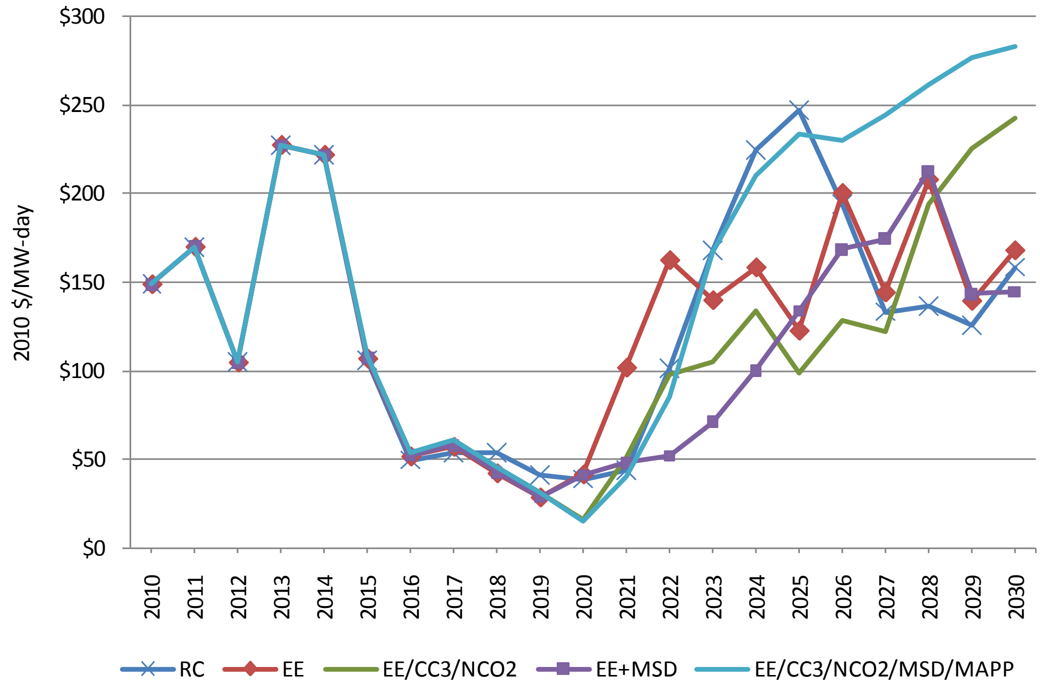
As shown in Figure 10.6 below, the LTER Reference Case modified for aggressive energy efficiency/conservation shows a consistent and sustained difference in capacity prices for PJM-SW. By 2030, this difference is estimated to be approximately $50 per MW-day. The other alternative scenarios that include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



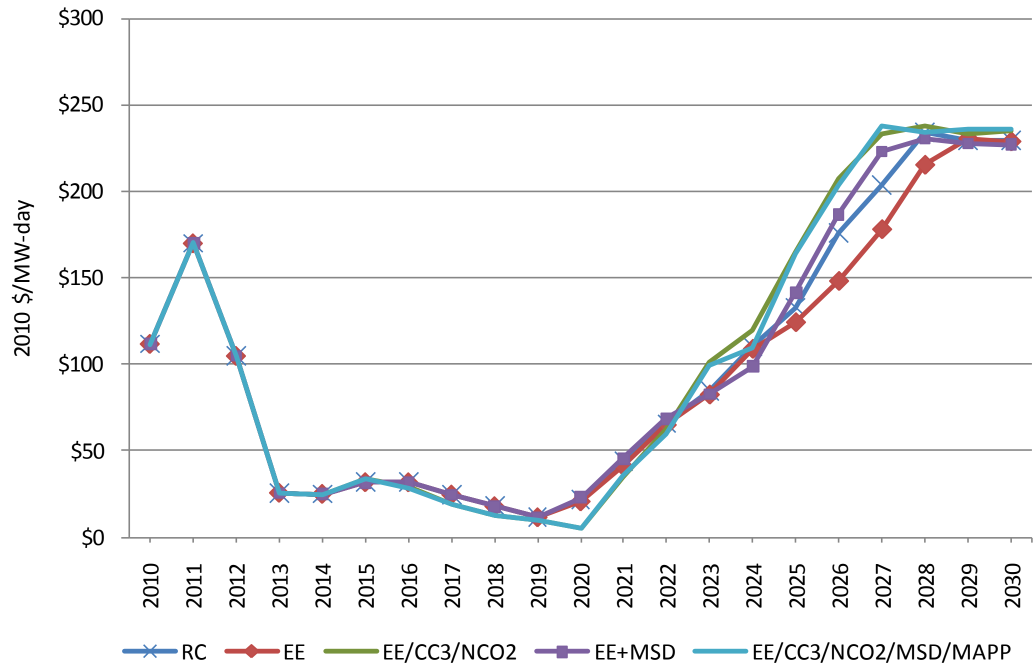
Capacity prices in PJM-MidE, shown in Figure 10.7 below, exhibit the same general instability that has characterized other scenario analyses, and there is no systematic and sustained relationship between capacity prices under the LTER Reference Case and any of the scenarios that include an aggressive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

Figure 10.7 PJM-MidE Capacity Prices – EE Scenarios



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 – EE Scenarios



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

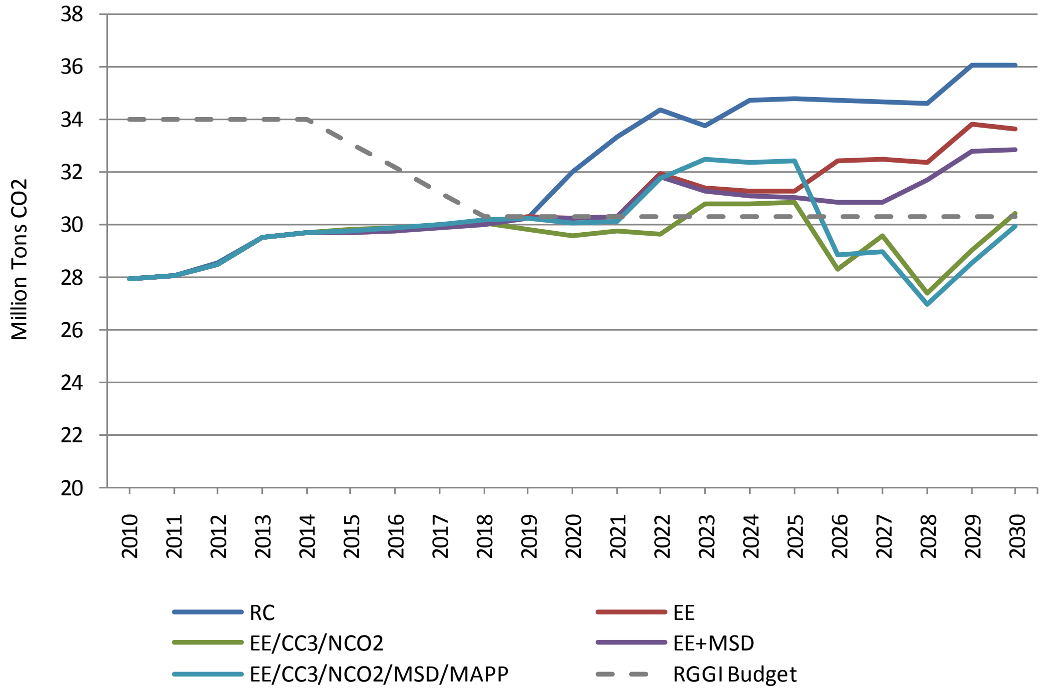
The 2030 emissions for each scenario for NO_x, SO_2, and CO_2 are summarized in Table 10.2 below. For Maryland plants subject to Healthy Air Act ("HAA") restrictions, SO_2 and NO_x emissions are nearly unchanged relative to the LTER Reference Case since it is still economical for these units to run at 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 Alternative Scenario Emissions From Electric Generation (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 Electric Generation CO_2 Emissions - EE Scenarios[40]



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.

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[40] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

- 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

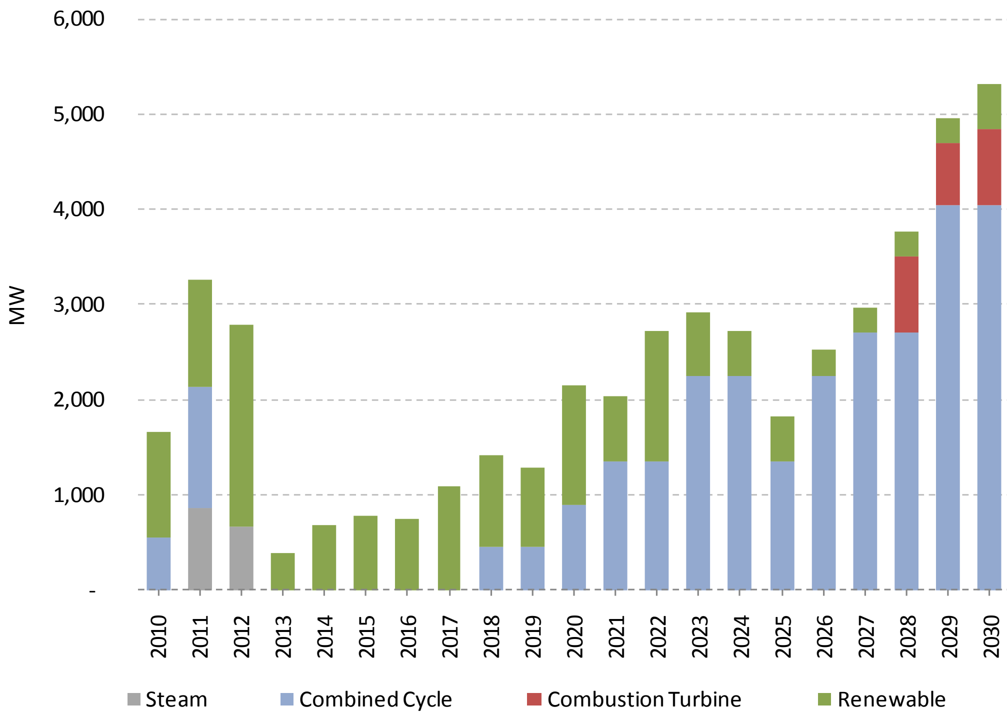
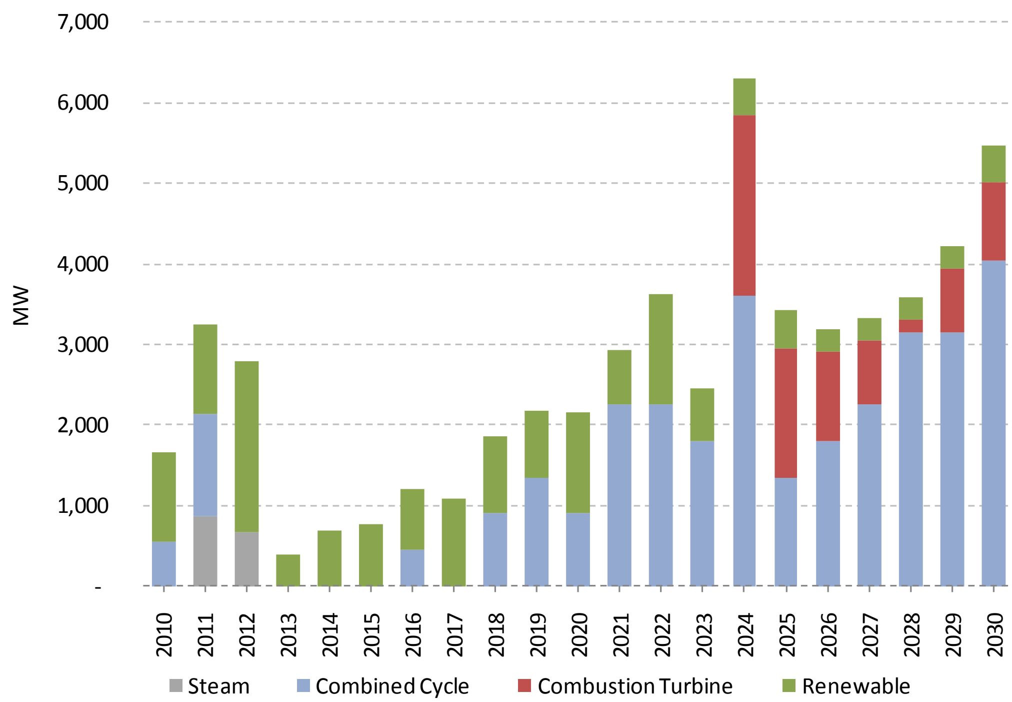


Figure 11.2 Climate Change Scenarios: Incremental Generation Additions in PJM



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 – Climate Change Scenarios

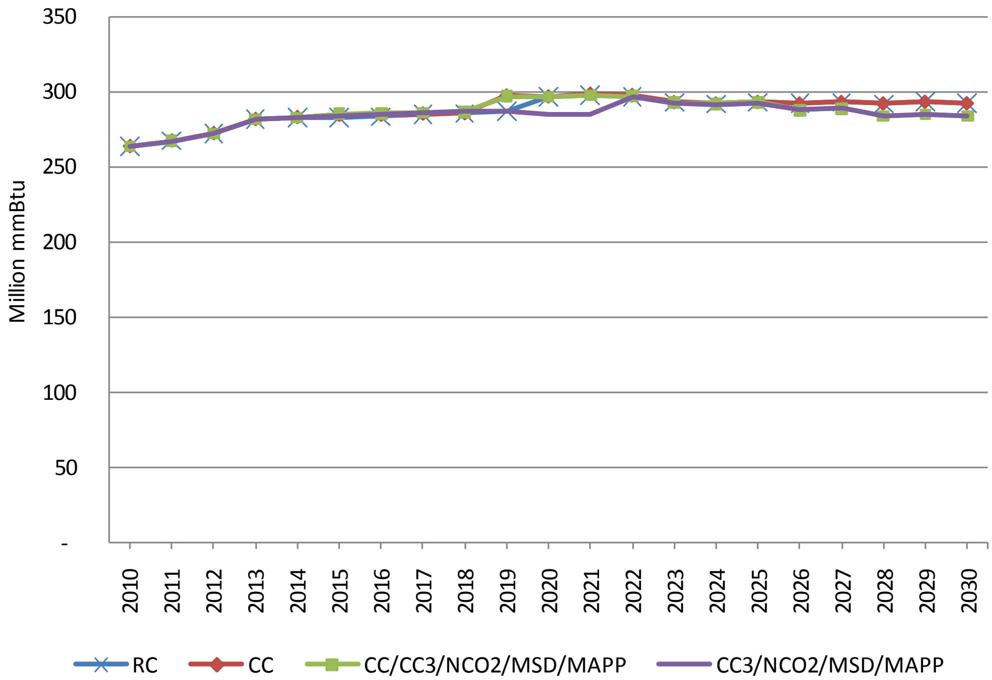
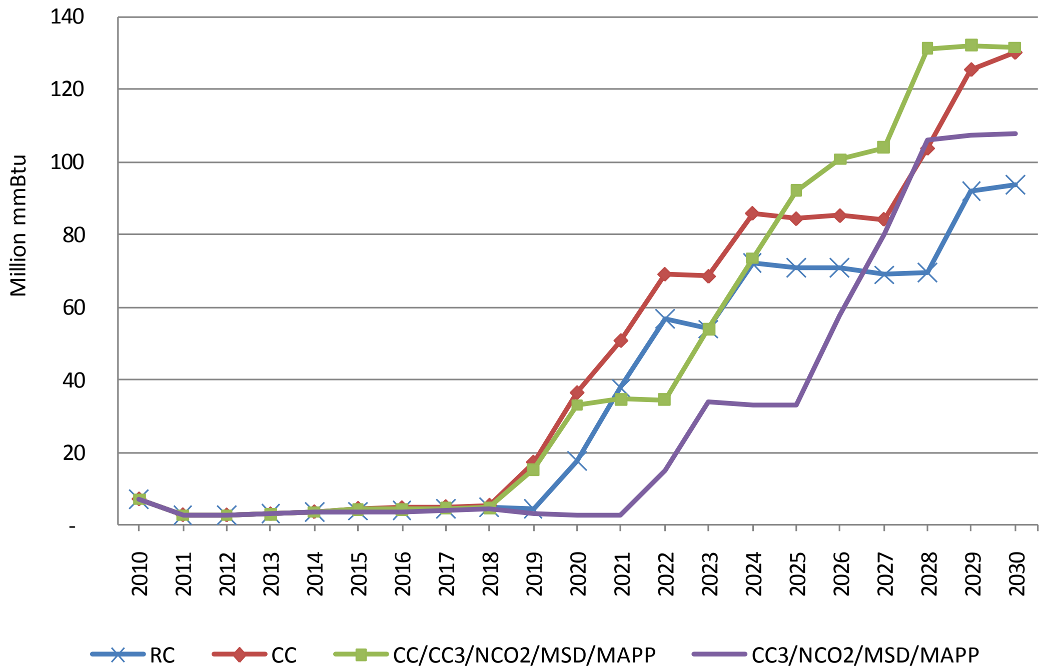


Figure 11.4 Natural Gas Use for Electricity Generation in Maryland – Climate Change Scenarios



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.

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 11.5 PJM-SW Net Imports – Climate Change Scenarios

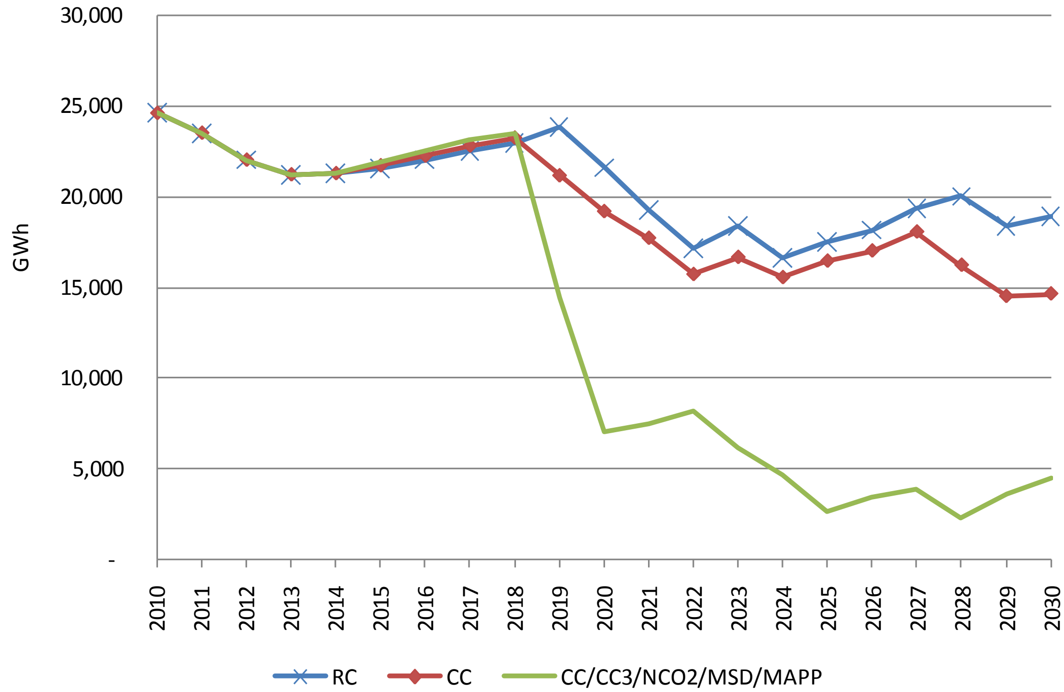
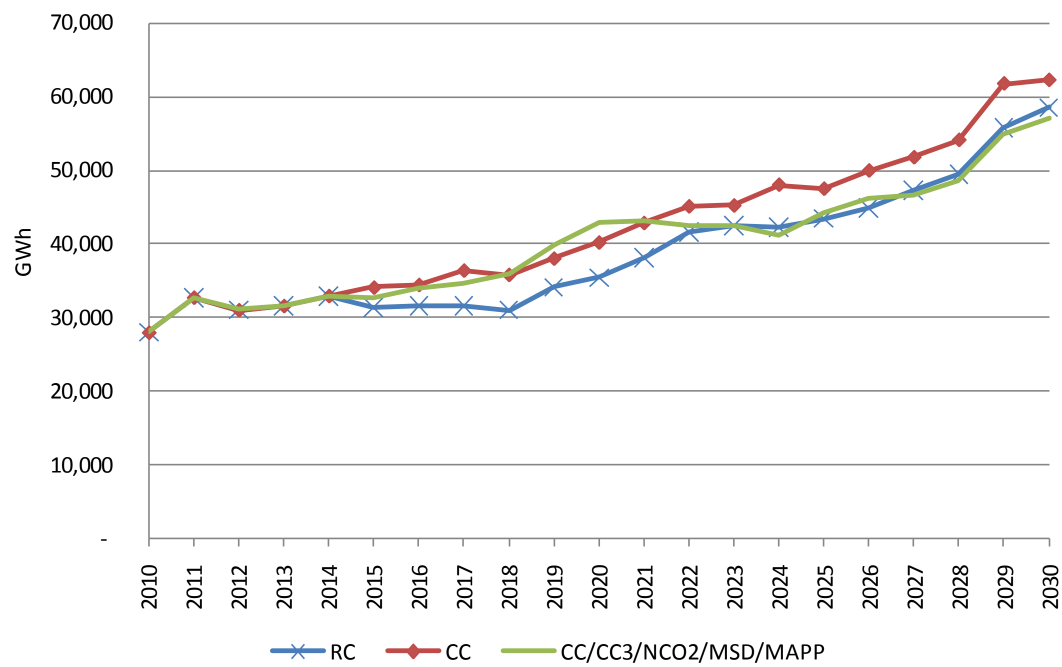
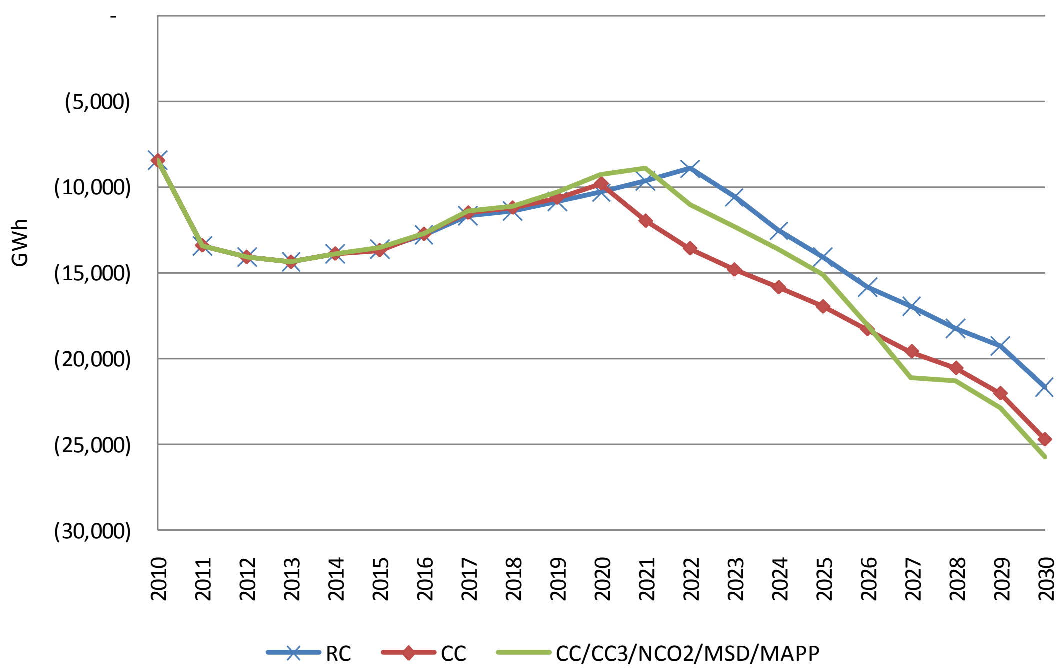


Figure 11.6 PJM-MidE Net Imports – Climate Change Scenarios



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 – Climate Change Scenarios



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

Figure 11.8 PJM-SW Real All-Hours Energy Price – Climate Change Scenarios

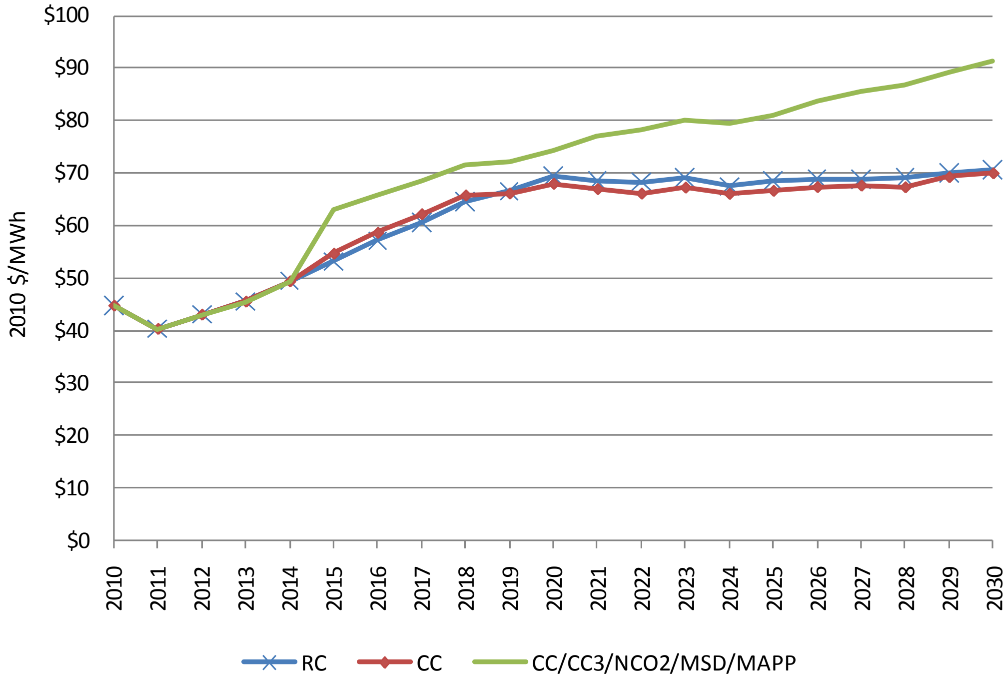


Figure 11.9 PJM-MidE Real All-Hours Energy Price – Climate Change Scenarios

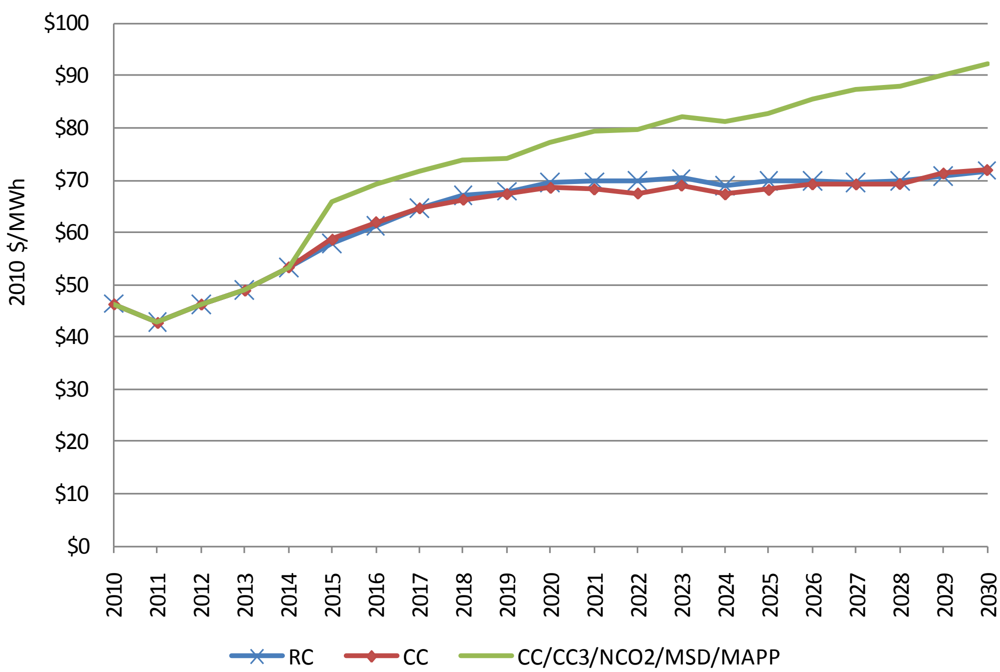
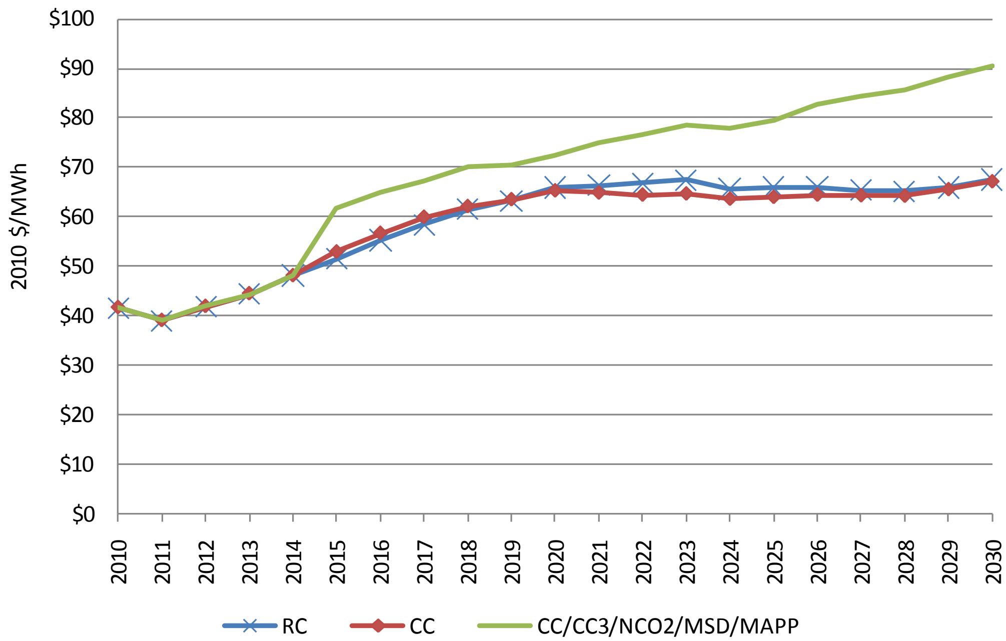


Figure 11.10 PJM-APS Real All-Hours Energy Price – Climate Change Scenarios



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 – Climate Change Scenarios

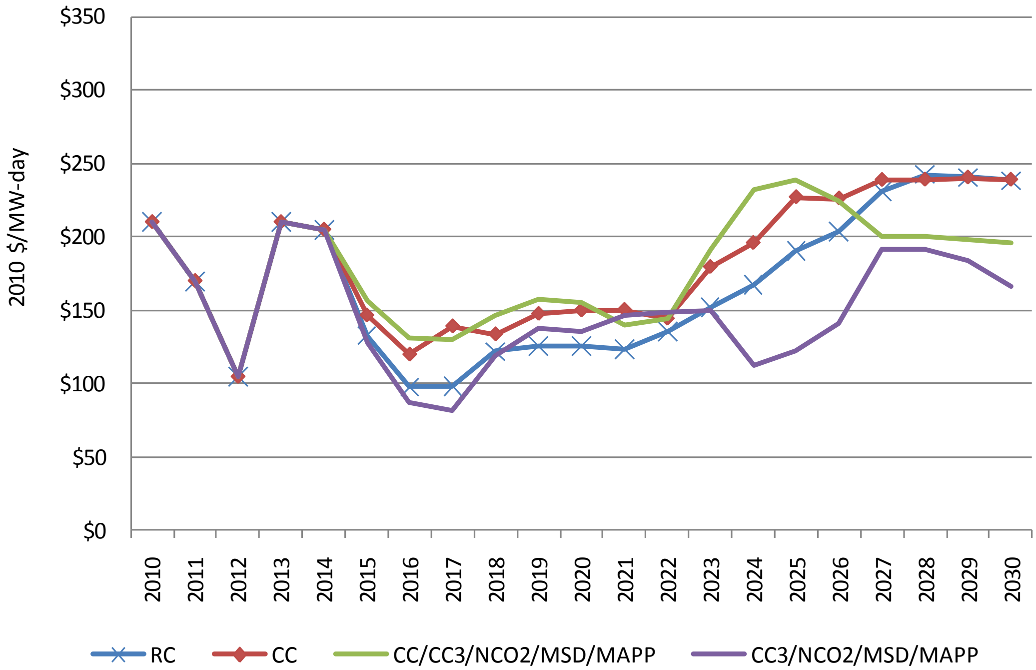


Figure 11.12 PJM-MidE Capacity Price – Climate Change Scenarios

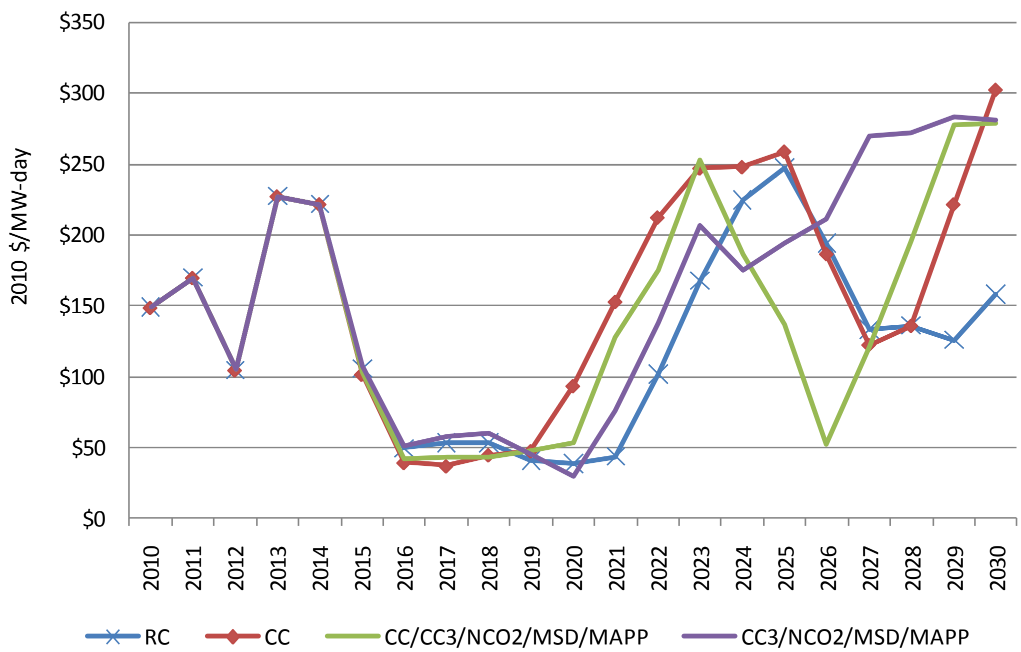
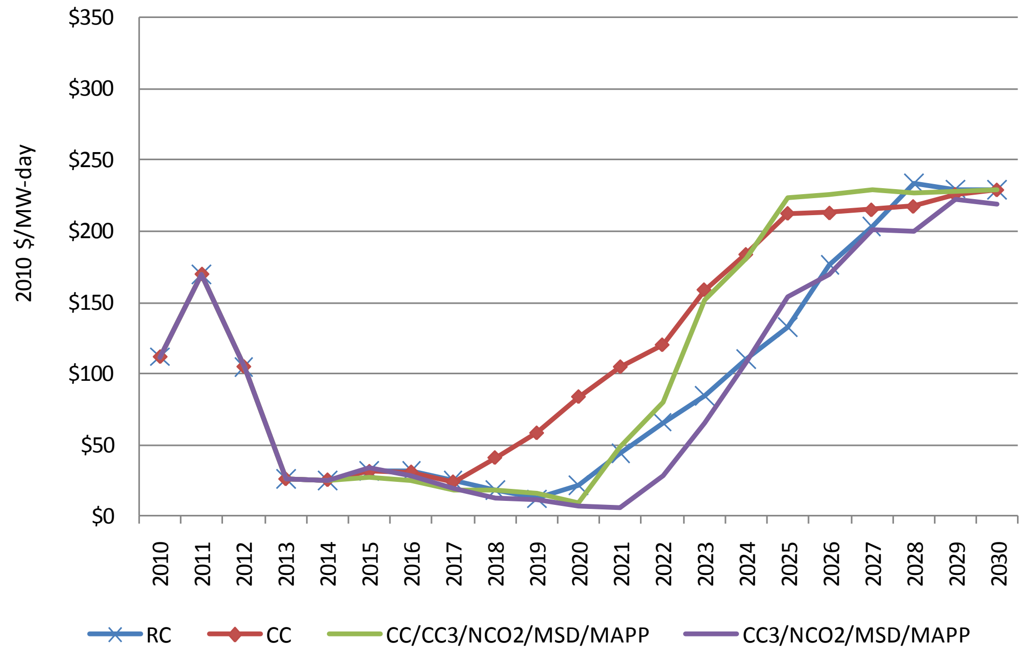


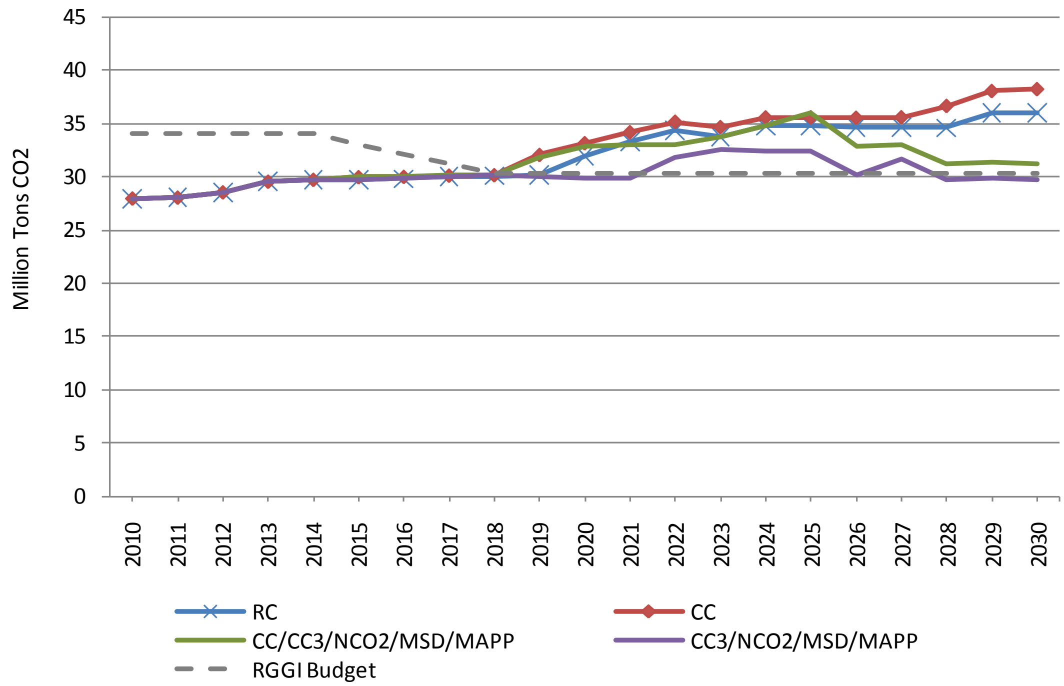
Figure 11.13 PJM-APS Capacity Price – Climate Change Scenarios



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 Maryland Electric Generation CO_2 Emissions – Climate Change Scenarios[41]



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.

[41] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

- 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. EPA PROPOSED REGULATIONS ALTERNATIVE SCENARIOS

12.1 Introduction

The Environmental Protection Agency ("EPA") is contemplating various regulations that could have significant impacts on the continued operation of existing coal-fired plants and the construction of new coal-fired power plants. This chapter presents two alternate scenarios to investigate the potential impacts of several proposed EPA regulations. In particular, we consider cooling tower water intake regulations, the Cross-State Air Pollution Rule affecting NO_x and SO_2 emissions, and the Electric Generating Unit Maximum Achievable Control Technology Rule for mercury emissions. Note that none of the regulations discussed herein are in final form, and as such, it is not possible to accurately project compliance costs. However, the cost estimates and operational impacts presented in this Chapter provide a useful gauge of potential effects. We present the projected effects of EPA regulations through two scenarios: one that contains the MSD line ("EPA Reg+MSD") and another that includes both the MSD and MAPP lines ("EPA Reg+MSD/MAPP"). The Oyster Creek nuclear power plant, located in New Jersey, is assumed to retire in 2019 in both scenarios, consistent with recently announced retirement plans.

12.2 Cooling Tower Regulations -- Section 316(b)

The EPA is poised to implement cooling water regulations on the cooling water that power plants use to cool their generators. The cooling water intake structures ("CWISs") that power plants use can harm aquatic wildlife and Section 316(b) of the Clean Water Act grants the EPA authority to develop regulations to mitigate those impacts. Years of legal challenges have left power plant CWISs exempt from the Clean Water Act, but the EPA is now compelled by court order to issue a final rule for CWIS by July 27, 2012.[42] The 316(b) regulations will affect 11 percent of steam electric generating facilities and over 45 percent of the electric generation capacity in the US.[43]

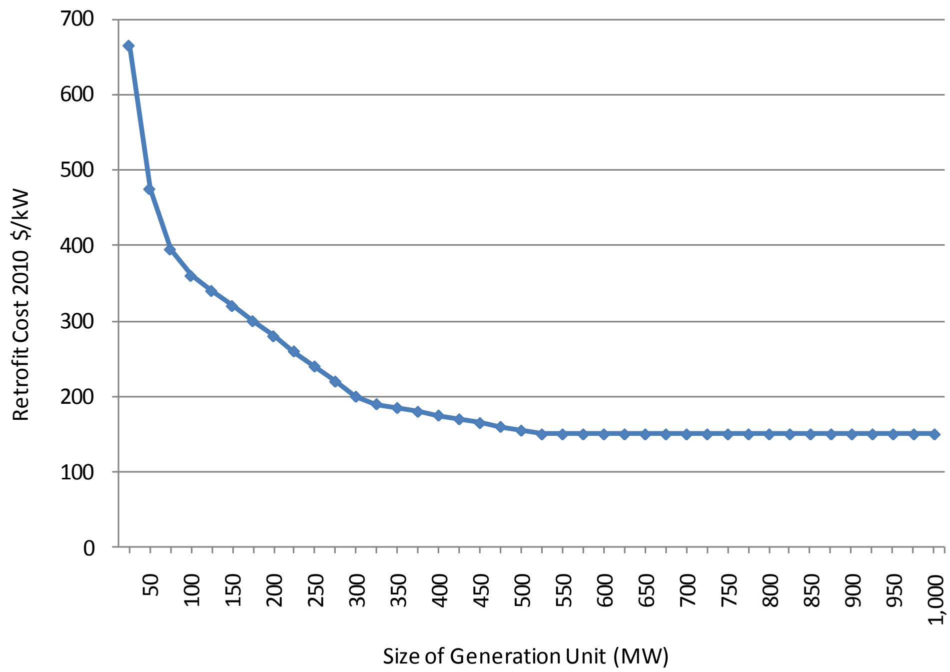
The two EPA scenarios presented herein assume implementation of the 316(b) regulations in 2015. Consistent with the assumptions being used by the Eastern Interconnection Planning Collaborative[44] ("EIPC") modeling project, all steam oil and steam gas units that have once-through cooling are assumed to retire. Additionally, all other once-through units with a capacity factor less than 35 percent were retired. The remaining steam units with CWISs install cooling tower retrofits in order to comply with 316(b). The cooling tower retrofit costs employed are based on an October 2010 North American Electric Reliability Corporation

[42] McCarthy J. and Copeland C., Congressional Research Service. "EPA's Regulation of Coal-Fired Power: Is a Train Wreck Coming?" August 8, 2011, p. 21.
[43] *Id*. at 21.
[44] The EIPC project involves a stakeholder-driven comprehensive analysis of the entire Eastern Interconnection. The EIPC is conducting extensive electric system analyses and aims to create an interconnection-wide regional transmission plan. For more information see: http://eipconline.com/

("NERC") Special Reliability Assessment of the impact of potential EPA regulations ("2010 NERC Assessment"), which were also relied upon in the development of the EIPC modeling assumptions.[45]

Figure 12.1 shows the estimated cooling tower retrofit costs which were used in the 2010 NERC Assessment and the EIPC analysis. The cooling tower retrofit costs in Figure 12.1 represent an estimate that reflects average costs but the actual retrofit costs vary widely by plant and are dependent on site-specific factors such as plant design and location.[46]

Figure 12.1 Cooling Tower Retrofit Cost Curve



Source: North American Reliability Corporation, "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations." Appendix II, October 2010.

The cooling tower retrofit costs, which are assumed to be applied in 2015, are treated as fixed O&M expenses and levelized over the remaining life of the plant. Installing cooling towers pursuant to 316(b) has a secondary effect of reducing the capacity of the plant because the retrofits involve new pumps that require energy to operate. Incorporating the cooling tower retrofit costs as an element of fixed O&M costs does not affect the marginal operating costs of the plants and as such, unit dispatch is not significantly affected. However, the retrofits do

[45] North American Electric Reliability Corporation, "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations." October 2010.
[46] McCarthy J. and Copeland C., Congressional Research Service. "EPA's Regulation of Coal-Fired Power: Is a Train Wreck Coming?" August 8, 2011, p. 49.

reduce net revenue margins. Table 12.1 presents the capacity de-rates associated with the cooling retrofits, which are consistent with the 2010 NERC Assessment.

Table 12.1 Power Plant De-rates after Cooling Tower Retrofit

NERC Subregion	De-Rate Percentage
RFC (PJM)	**3.4%**
FRCC	2.5%
MRO	3.1%
SPP	2.8%
NYISO	3.2%
NPCC	3.4%
SERC Delta	2.6%
SERC Southeastern	2.4%
SERC Central	2.6%
SERC VACAR	2.8%

Source: North American Reliability Corporation, "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations." October 2010, Appendix II, p. 46.

Table 12.2 presents the estimated power plant retirements and de-rates due to retrofits associated with implementing the 316(b) regulations. Throughout the Eastern Interconnection, 41.6 GW of capacity is retired.[47] Just over 3 GW is retired within PJM. The majority of the retirements in the Eastern Interconnection are located in the southeast. Of the 3,125 MW of retirements in PJM, 587 MW are located in Maryland. In addition to the retirements, plant capacity was lost due to the de-rates as described in Table 12.1. The assumed capacity lost to cooling tower-relates de-rates totals 3,786 MW in the Eastern Interconnection.

Table 12.2 Estimated 316(b) Power Plant Capacity Reductions by Region

Region	Retirements (MW)	De-rates (MW)	Total Capacity Reduction (MW)
Midwest ISO	2,443	1,199	3,642
ISO New England	5,642	89	5,731
New York ISO	11,819	71	11,890
PJM Interconnection	**3,125**	**1,208**	**4,333**
Rest of Eastern Interconnection	18,589	1,220	19,809
Total Eastern Interconnection	41,617	3,786	45,403

[47] This result is comparable to the EIPC business as usual result where approximately 48 GW of coal and steam oil/gas capacity retired in 2020 following the imposition of the additional costs associated with the proposed EPA regulations. http://eipconline.com/uploads/EIPC_BAU_MRN-NEEM_Results_3-20-11.pdf

Of the 1,208 MW of de-rates in PJM, 116 MW come from existing coal-fired capacity in Maryland. With respect to the three PJM zones that encompass Maryland, 213 MW are located in PJM-SW, 57 MW in PJM-MidE, and 35 MW in PJM-APS. In total, 703 MW of coal capacity is lost pursuant to 316(b): 587 MW from retirements and 116 MW from de-rates after retrofits.

12.3 CSAPR and MATS

Following estimation of the retirements associated with implementation of the 316(b) regulations, NO_x and SO_2 controls to comply with the Cross-State Air Pollution Rule ("CSAPR") are assumed to be added to coal-fired units with generating capacity in excess of 400 MW that do not already have controls. These controls, in addition to the EPA Transport Rule already reflected in the LTER Reference Case, satisfy all SO_2 controls and NO_x controls required on an aggregate basis. The potential Utility Mercury and Air Toxics ("MATS") for mercury under the EPA's Clean Air Act are not directly reflected in the LTER EPA scenarios because the incremental cost of controlling for mercury after SO_2 controls are added is relatively minor. Finally, additional fly ash controls associated with potential Coal Combustion Waste management rules are not imposed because the 2010 NERC Assessment found that coal ash disposal costs would have to reach $500 per ton to trigger additional retirements, which is above the expected levels.[48]

12.4 Capacity Additions

As noted previously in this Chapter, implementation of the proposed EPA regulations result in over 3 GW of retirements in PJM and 2,175 from RFC-MISO, which exports power to the PJM. Additional generic natural gas capacity is needed to replace the capacity that retires as a result of the EPA regulations if load and reliability requirements are to be met. Table 12.3 shows the cumulative natural gas capacity additions through 2030. In PJM as a whole, the EPA regulations cause the construction of approximately 34 GW of new capacity in the EPA Reg+MSD and EPA Reg+MSD/MAPP scenarios. This constitutes an increase over the LTER Reference Case plus Mt. Storm to Doubs ("MSD") scenario of about 4 GW.

Table 12.3 Cumulative Natural Gas Capacity Added Through 2030 – EPA Scenarios

Scenario	PJM-SW	PJM-MidE	PJM-APS	PJM Total
MSD	1,431	3,816	4,770	30,145
EPA Reg+MSD	2,604	2,345	5,724	34,011
EPA Reg+MSD/MAPP	2,862	2,390	5,247	33,966

[48] North American Electric Reliability Corporation, "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations." October 2010, pp. 21-22.

In PJM-SW, an additional 1,173 MW of capacity is built in the EPA Reg+MSD scenario relative to the MSD scenario. Consistent with earlier results, the MAPP line results in additional natural gas construction in the PJM-SW zone, and with the EPA regulations, the EPA Reg+MSD/MAPP line involves an additional 1,431 MW of capacity relative to the MSD scenario.

PJM-MidE builds less capacity under the EPA Reg+MSD scenario because no capacity was retired in that zone as a result of the cooling tower retrofits and other regions build natural gas capacity which is available for export to PJM-MidE. Relative to the MSD scenario, PJM-APS builds an additional 954 MW and 477 MW of new natural gas capacity in the EPA Reg+MSD and EPA Reg+MSD/MAPP scenarios, respectively. Figure 12.2 through Figure 12.4 show the new natural gas capacity additions in the three zones that encompass Maryland.

Figure 12.2 PJM-SW Natural Gas Capacity Additions – EPA Scenarios

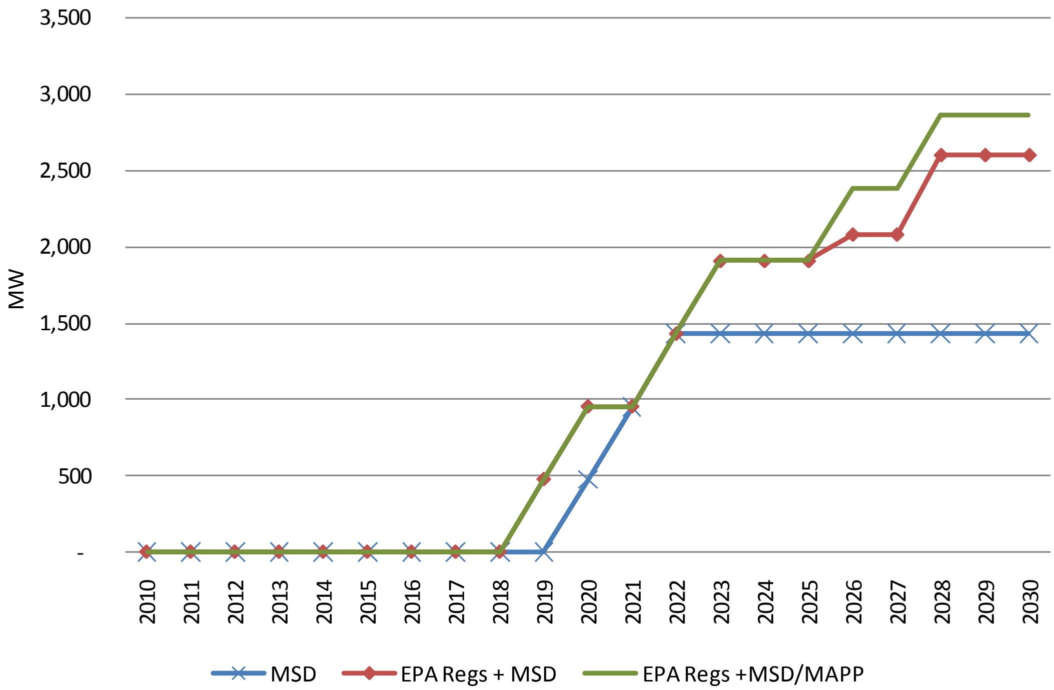


Figure 12.3 PJM-MidE Natural Gas Capacity Additions – EPA Scenarios

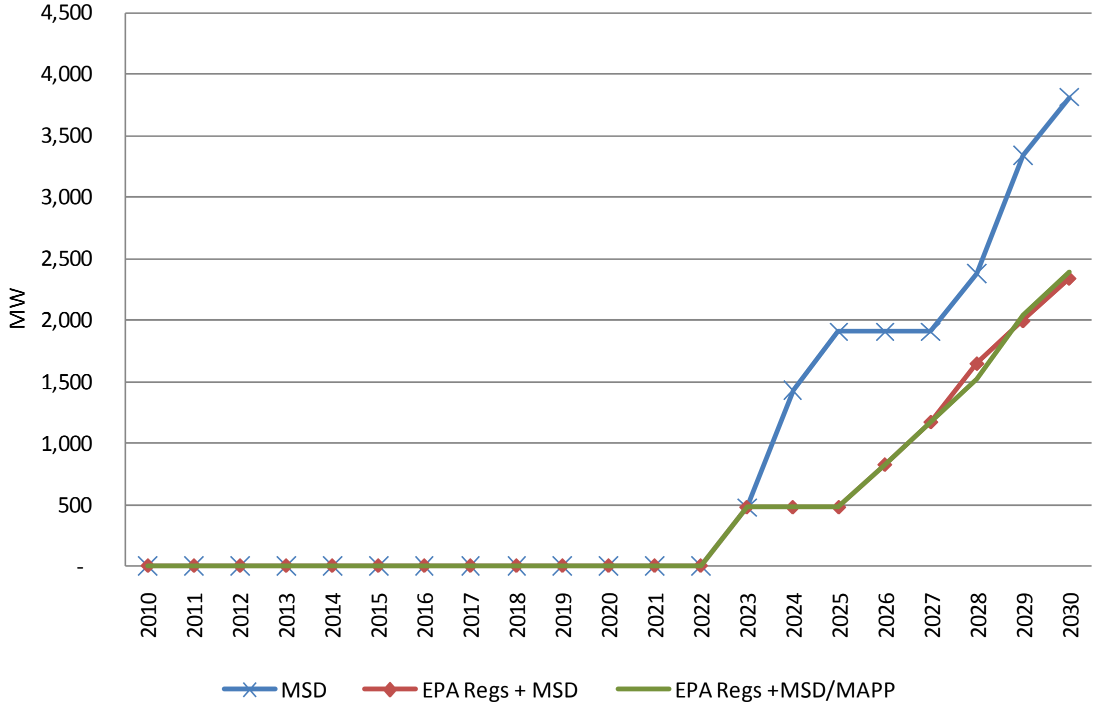
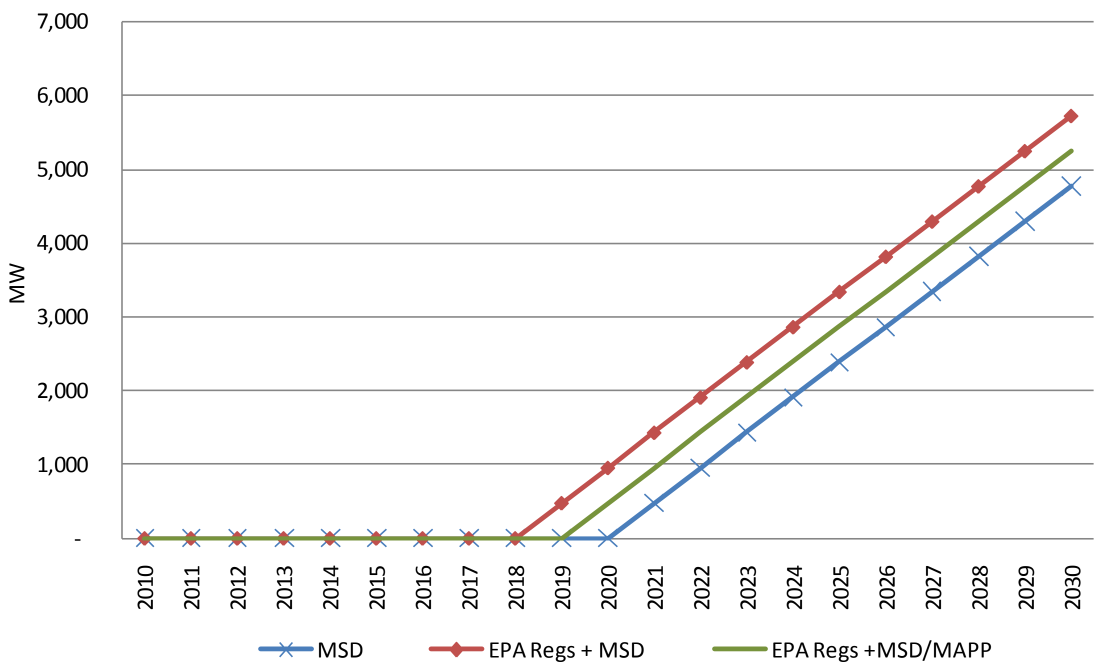


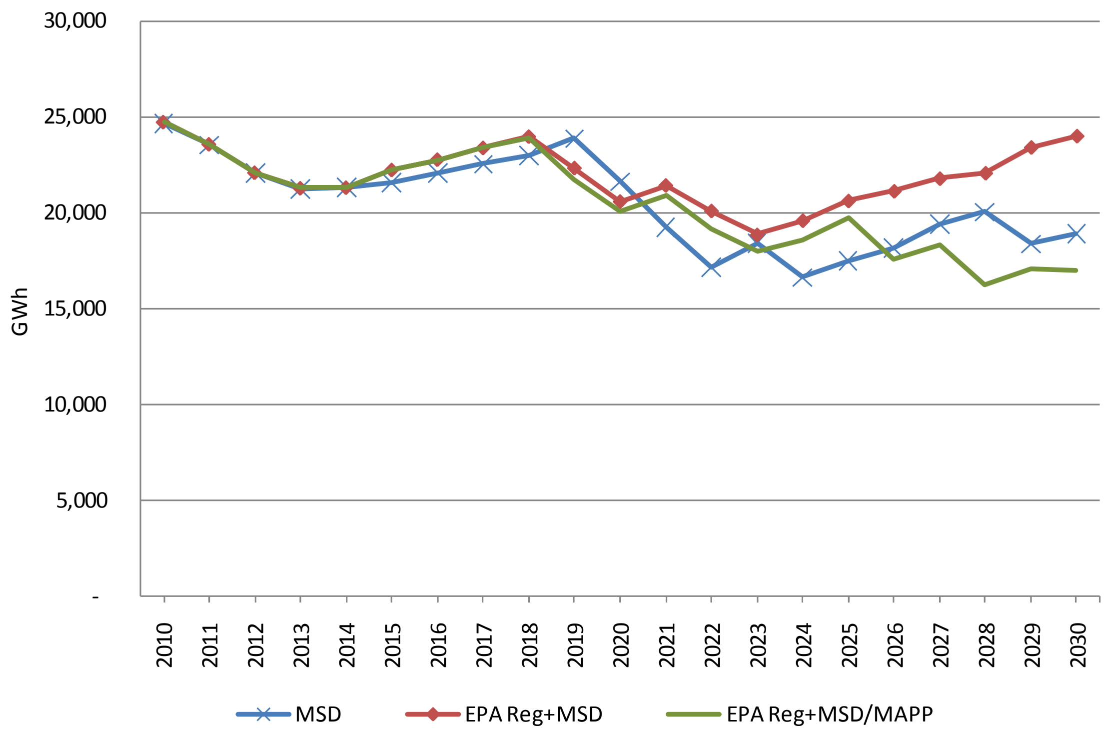
Figure 12.4 PJM-APS Natural Gas Capacity Additions – EPA Scenarios



12.5 Net Energy Imports

The coal-fired power plant retirements in the EPA scenarios tend to increase the PJM-SW zone's net imports due to the lost internal capacity in the zone, and PJM-SW's net imports in the EPA Reg+MSD scenario are higher than the MSD scenario. With the MAPP line, the net effect of the coal retirements and new natural gas builds effectively cancel each other out in the EPA Reg+MSD/MAPP scenario, which is very similar to the MSD scenario with the differences between the scenarios largely driven by the natural gas build schedules.

Figure 12.5 PJM-SW Net Imports – EPA Scenarios



The EPA regulations reduce the level of natural gas capacity additions in PJM-MidE and as a result, PJM-MidE's net imports under the EPA Reg+MSD and EPA Reg+MSD/MAPP scenarios are both above the MSD scenario (see Figure 12.6).

The EPA regulations result in increased exports from PJM-APS, some of which are exported to PJM-MidE. Net imports for PJM-APS under the two EPA scenarios and under the MSD scenario are shown in Figure 12.7.

Figure 12.6 PJM-MidE Net Imports – EPA Scenarios

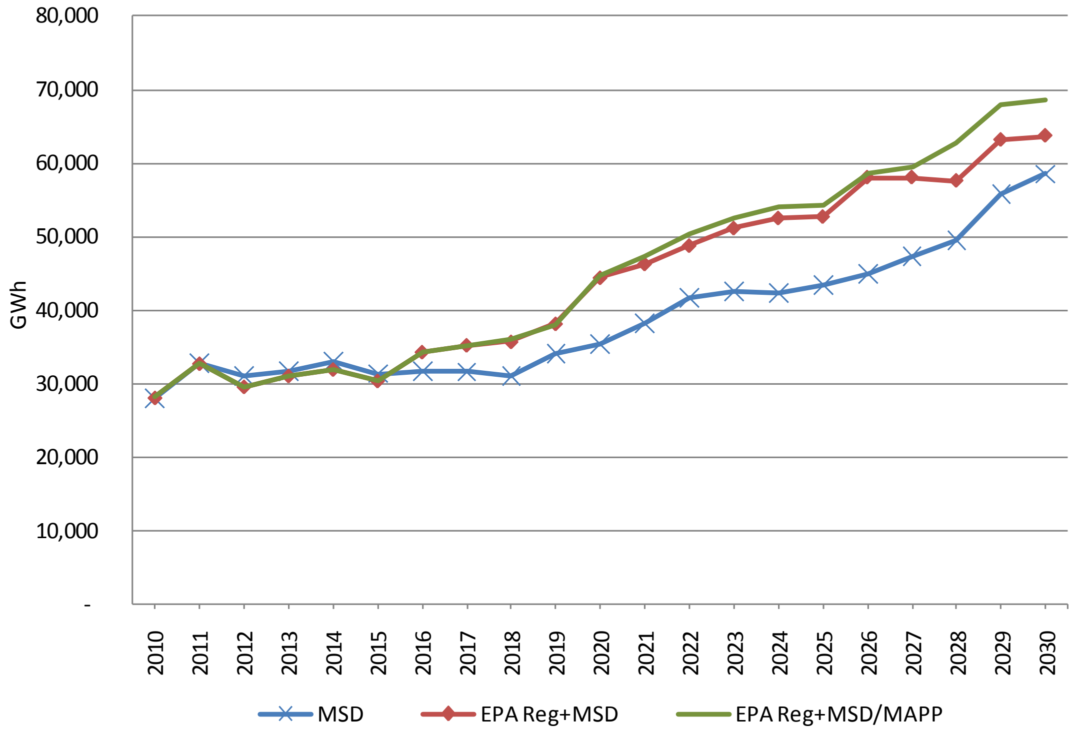
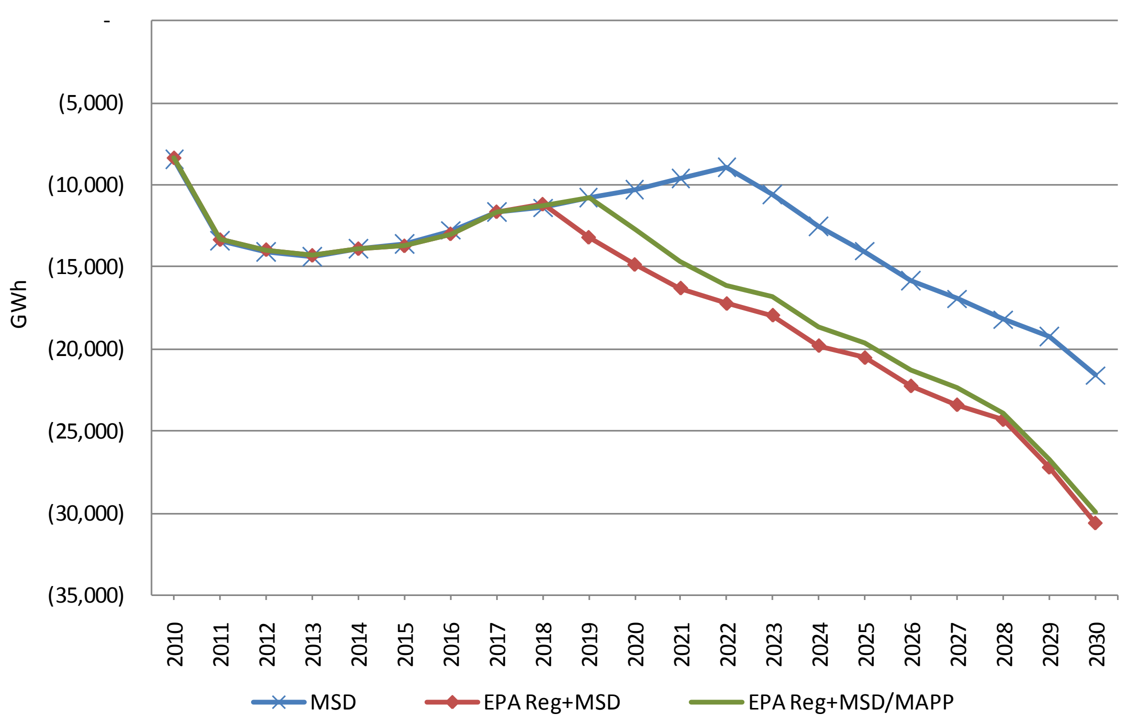


Figure 12.7 PJM-APS Net Imports – EPA Scenarios



12.6 Fuel Use

Projected fuel use in Maryland under the EPA scenarios is consistent with the coal-fired plant retirements and natural gas builds. Natural gas use is shown to be higher in 2030 under the two EPA scenarios relative to MSD scenarios (see Table 12.4). As in previous scenarios, the MAPP line results in a significant amount of additional gas generation in Maryland relative to scenarios that exclude the MAPP line.

Table 12.4 Fuel Use for Electricity Generation in 2030 – EPA Scenarios

Scenario	Coal (mmBtu)	Natural Gas (mmBtu)
MSD	291,989,236	43,068,200
EPA Reg+MSD	285,541,622	64,532,044
EPA Reg+MSD/MAPP	285,626,881	111,453,576

Coal use in Maryland under the EPA scenarios is reduced because of the 587 MW of coal plant retirements occurring in Maryland and the 703 MW of lost coal capacity as a result of retrofit de-rates. However, the de-rated coal plants continue to operate throughout the forecast period in each of the two EPA scenarios.

12.7 Energy Prices

The EPA regulations result in transitory wholesale energy price increases in PJM-SW between 2015, when they come into effect, and 2019. This happens because natural gas is the marginal resource in more hours after the retirement of coal-fired capacity. However, the two EPA scenarios closely track the MSD scenario after 2020 (see Figure 12.8), when new natural gas-fired capacity begins being constructed under the MSD scenario.

Energy prices in PJM-MidE (Figure 12.9) follow a pattern similar to energy prices in PJM-SW and for the same reasons. The coal plants affected by the 316(b) and CSAPR rules typically operate as base load capacity both before and after the EPA-related retrofits, and as such, generally do not operate as the marginal units in each zone but are marginal in some of the hours of the year. The reduction in the number of hours that coal is the marginal fuel affects wholesale energy prices between 2015 and 2020. PJM-APS energy prices follow a similar pattern to PJM-SW and PJM-MidE (see Figure 12.10).

Figure 12.8 PJM-SW Real All-Hours Energy Price – EPA Scenarios

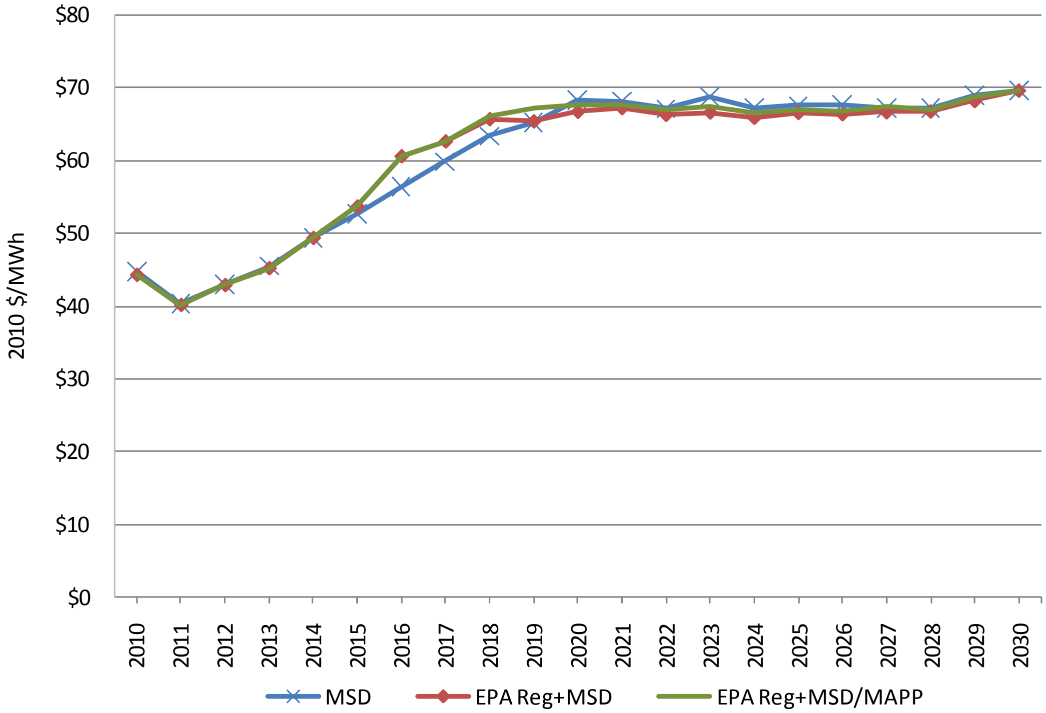


Figure 12.9 PJM-MidE All-Hours Energy Price – EPA Scenarios

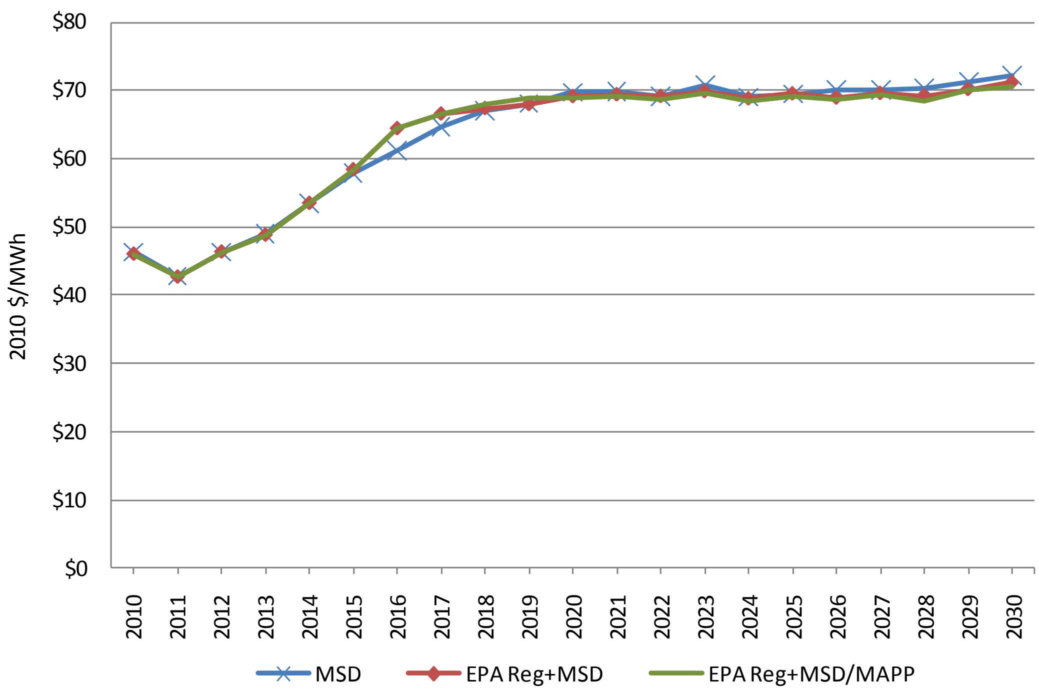
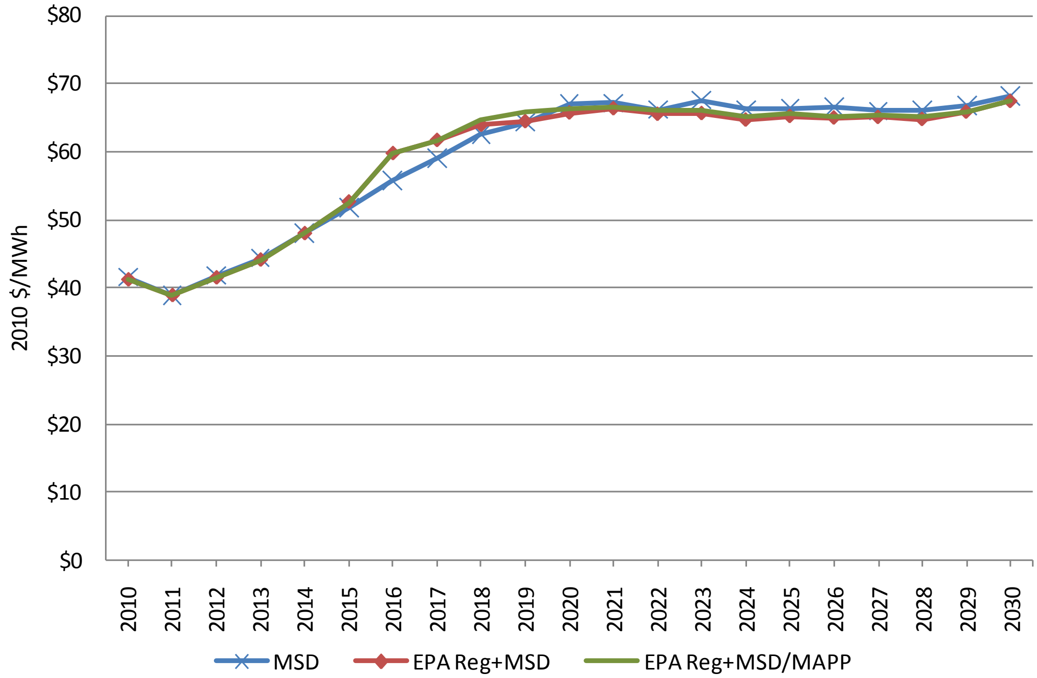


Figure 12.10 PJM-APS Real All-Hours Energy Price – EPA Scenarios

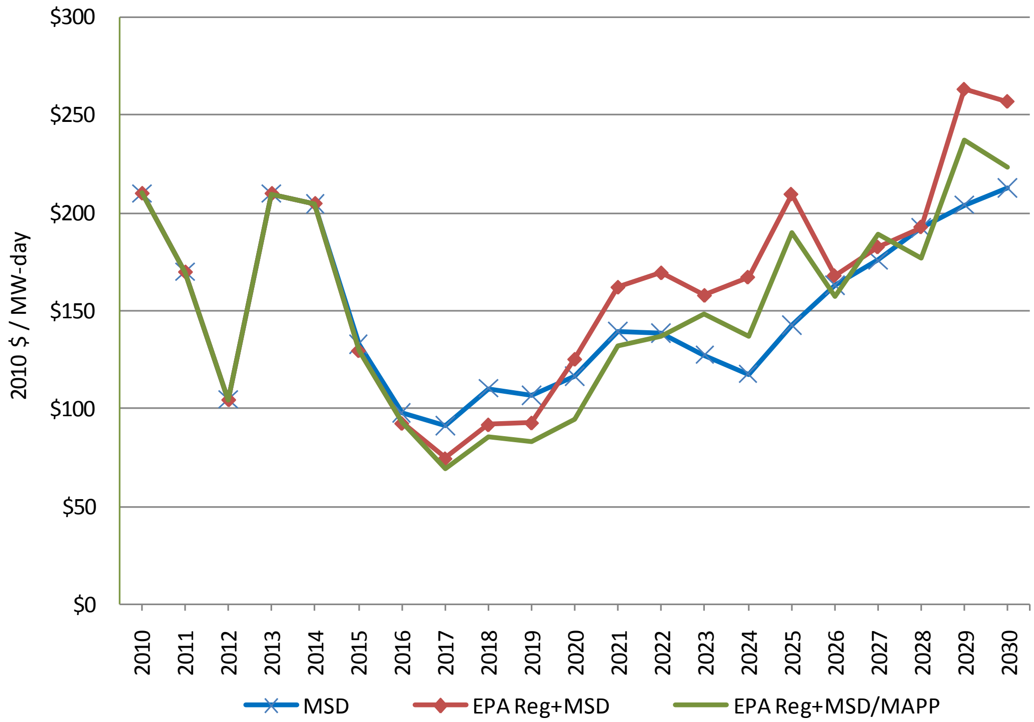


Note that wholesale energy prices in all three PJM zones are slightly lower under the EPA scenarios than under the MSD scenario after 2020. The reason for this is the added construction of new efficient natural gas plants under the EPA scenarios.

12.8 Capacity Prices

Capacity prices for the EPA scenarios show a tendency to be higher than the capacity prices under the MSD scenario in all three Maryland zones, but there is no consistent and sustained relationship over the study period. The generally higher capacity prices under the EPA scenarios relative the MSD scenario are, in part, attributable to the slightly lower wholesale energy prices associated with the EPA scenarios. In PJM-SW (Figure 12.11) the EPA scenarios show capacity prices slightly above the MSD scenario by 2030, but capacity prices under all three scenarios exhibit a similar pattern of gradual increase over the 20-year study period.

Figure 12.11 PJM-SW Capacity Prices – EPA Scenarios



Similarly, the EPA regulations do not result in consistent and sustained differences in capacity prices in PJM-MidE (Figure 12.12) relative to the capacity prices for the MSD scenario. Capacity prices are driven by the new natural gas capacity build schedules and the prices in all three scenarios converge by 2030. Capacity prices in PJM-APS under the EPA Reg+MSD and EPA Reg+MSD/MAPP scenarios are above the capacity prices obtained for the MSD scenario through the late 2020s, as existing capacity is de-rated and new generic capacity is built, but all three scenarios converge by 2030 (Figure 12.13). There are no substantial differences between the capacity prices in the APS zone for the two EPA scenarios.

Figure 12.12 PJM-MidE Capacity Prices – EPA Scenarios

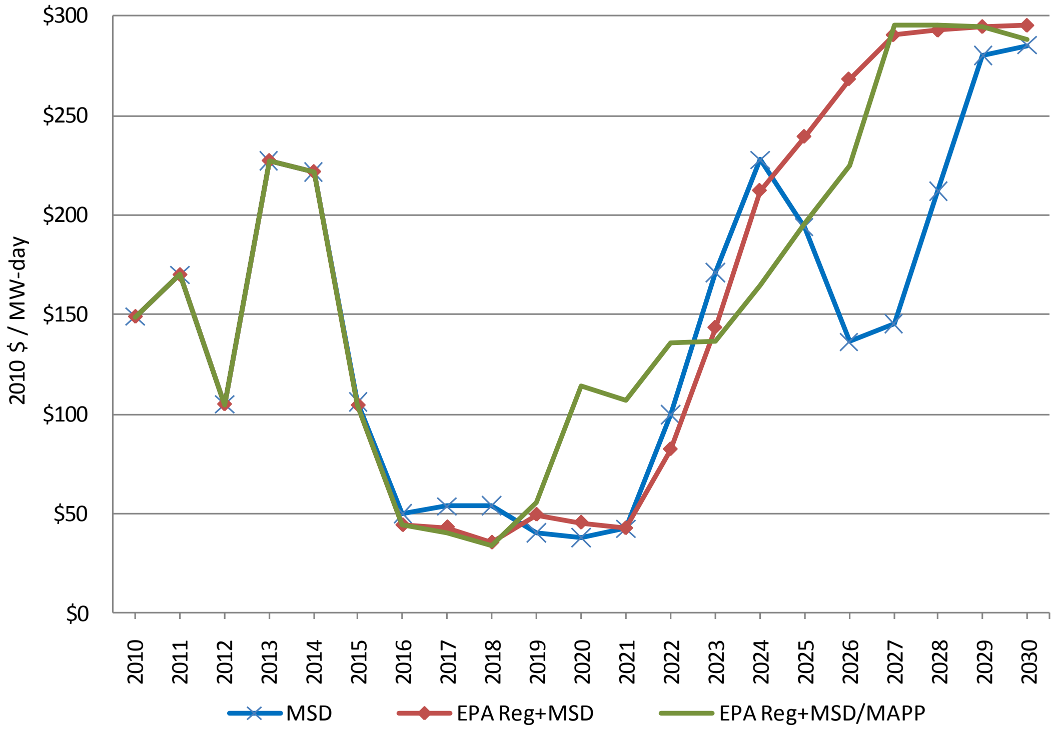
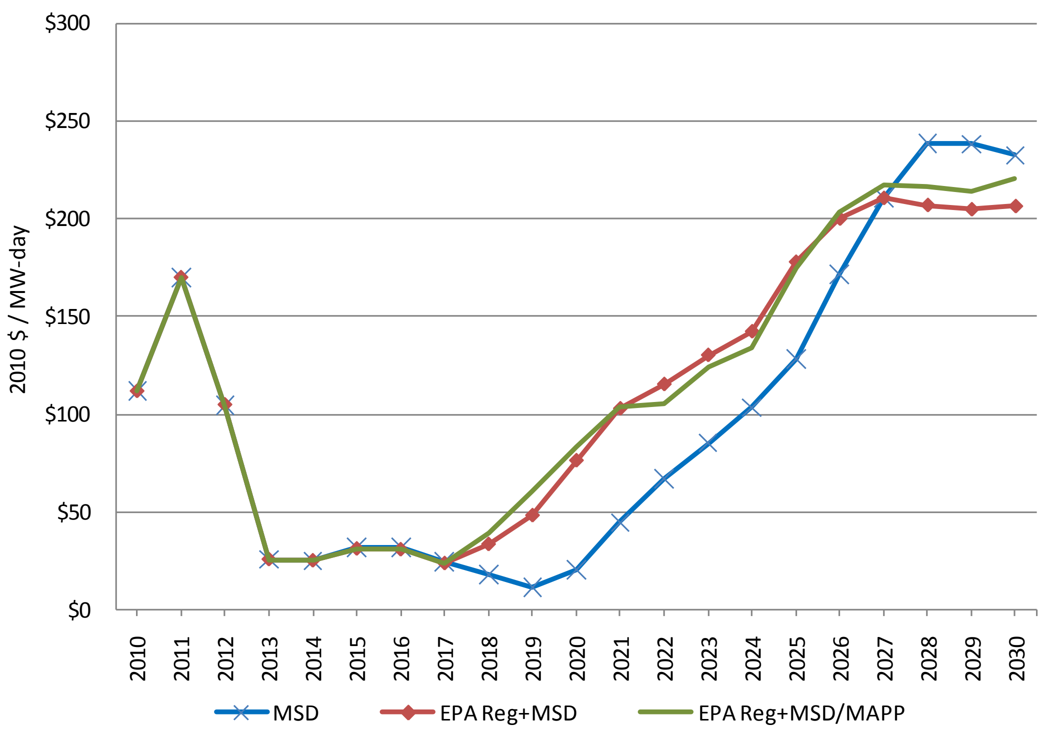


Figure 12.13 PJM-APS Capacity Prices – EPA Scenarios



12.9 Emissions

Most of the coal-fired capacity in Maryland already have NO_x and SO_2 controls pursuant to Maryland's Healthy Air Act. However, the 316(b) regulations result in the loss of 703 MW of coal-fired capacity in the State. Figure 12.14 shows that the total level of SO_2 emissions is reduced because of the retirements and de-rates in 2015. NO_x emissions (Figure 12.15) follow a similar pattern to the SO_2 emissions but NO_x emissions are higher in the EPA Reg+MSD/MAPP scenario than the EPA Reg+MSD scenario because the MAPP project results in more new natural gas capacity and generation in Maryland. However, the NO_x and SO_2 emissions are both below the MSD scenario beyond 2015.

Figure 12.14 Maryland HAA Plant SO_2 Emissions – EPA Scenarios

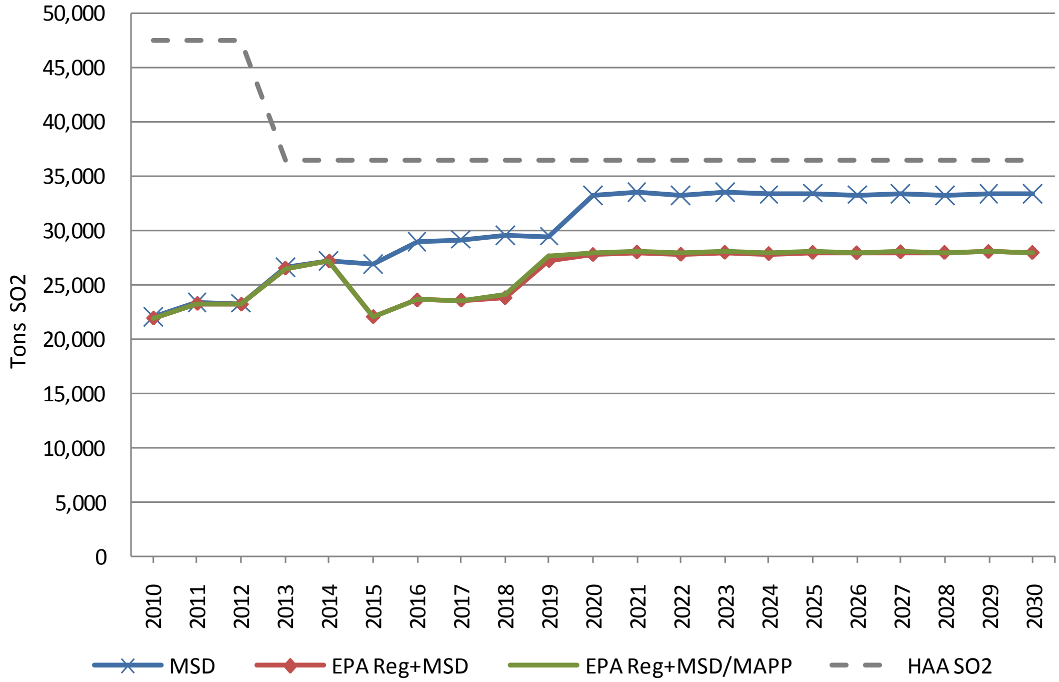
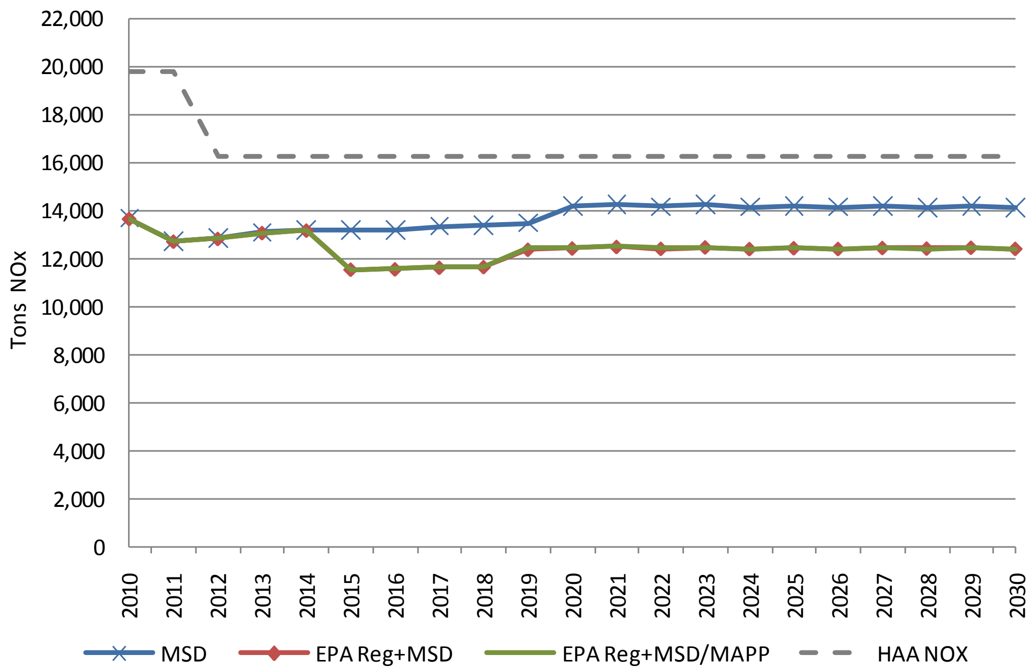


Figure 12.15 Maryland HAA Plant NO_x Emissions – EPA Scenarios



CO_2 emissions for both of the EPA scenarios are above those for the MSD scenario toward the end of the study period. Both of the EPA scenarios involve lower levels of coal generation than the MSD scenario, consequently, the higher CO_2 emissions after 2025 in the EPA Reg+MSD/MAPP scenario results from increased natural gas generation in Maryland. Emissions under the EPA Reg+MSD scenario are very close to the MSD scenario emissions by 2030.

The EPA emissions results for Maryland are not typical throughout PJM (see

Figure 12.17). CO_2 emissions in PJM under both of the EPA scenarios are lower than the MSD scenario. The effect of the 316(b) regulations and retrofits are less pronounced in Maryland than in PJM as a whole because most of the coal plants in Maryland are already controlled under the Healthy Air Act.

Figure 12.16 Maryland Electric Generation CO_2 Emissions – EPA Scenarios[49]

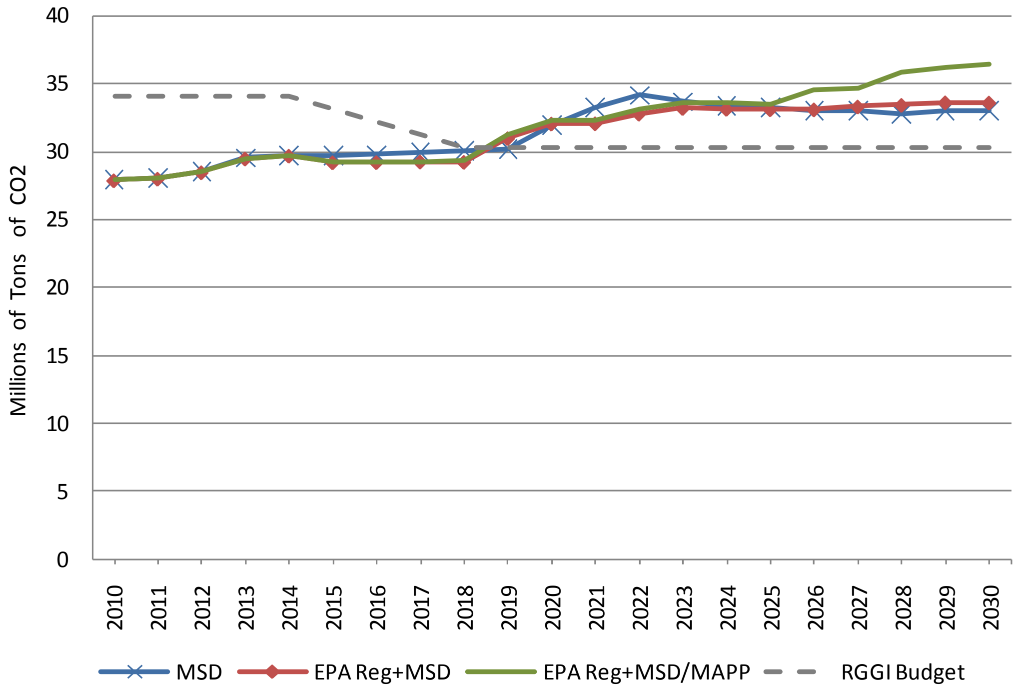
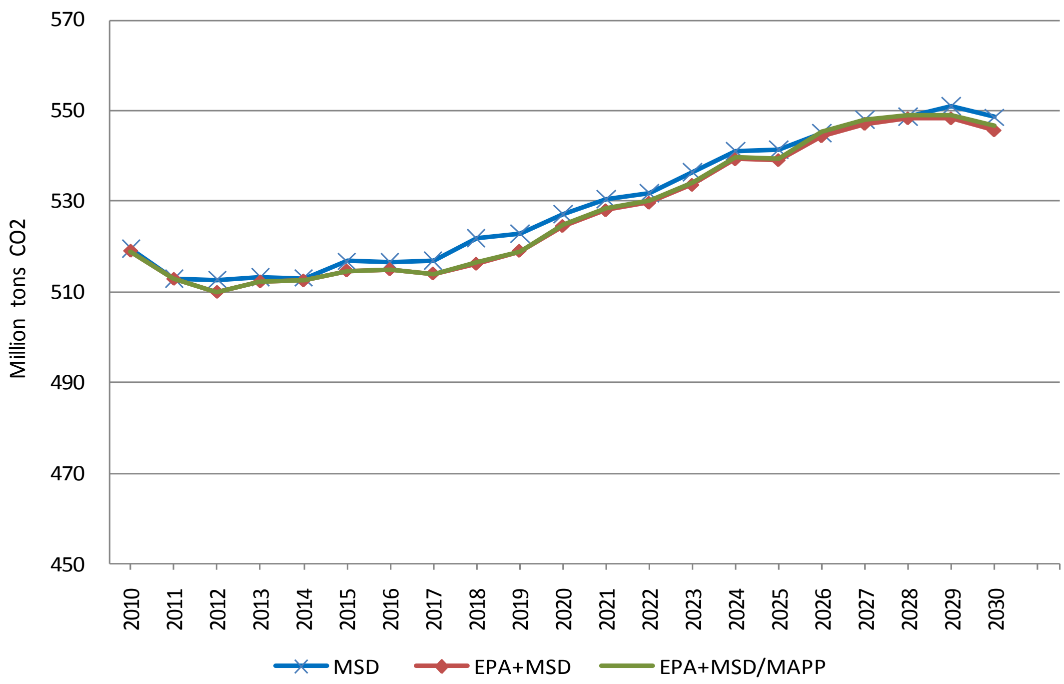


Figure 12.17 PJM Electric Generation CO_2 Emissions – EPA Scenarios



[49] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

12.10 Results

The key results from the EPA scenarios are as follows:

- The proposed EPA regulations result in 3 GW of coal-fired capacity retiring in PJM as a whole, with 587 MW of the total retiring in Maryland. Additionally, de-rates due to capacity losses resulting from retrofits leads to 1,200 MW of total capacity reductions in PJM as a whole, with 116 MW of the total in Maryland.
- As a result of the capacity reductions due to retirements and retrofit de-rates, approximately 4 GW of additional new natural gas capacity is constructed in PJM under the EPA scenarios relative to the MSD scenario. In PJM-SW, approximately 1,200 MW of additional new natural gas capacity is constructed under the EPA+MSD scenario and 1,400 MW under the EPA+MSD/MAPP scenario, relative to the MSD scenario.
- EPA regulations result in only a transitory wholesale energy price increase between 2015 and 2019 relative to the MSD, scenario. However, since the cost of the retrofits are fixed, they do not affect plant dispatch.
- Most of the coal-fired capacity in Maryland has already installed controls pursuant to Maryland's Healthy Air Act so the proposed EPA regulations will have less of an impact on emissions in Maryland than they would in PJM as a whole.
- None of the EPA regulations modeled herein are in final form and significant uncertainty exists as to what the final EPA regulations will ultimately contain. As such, the actual future impacts of the new rules will likely differ from the estimates presented in this chapter.

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13. PPRAC-IDENTIFIED ADDITIONAL ALTERNATIVE SCENARIOS

13.1 Introduction

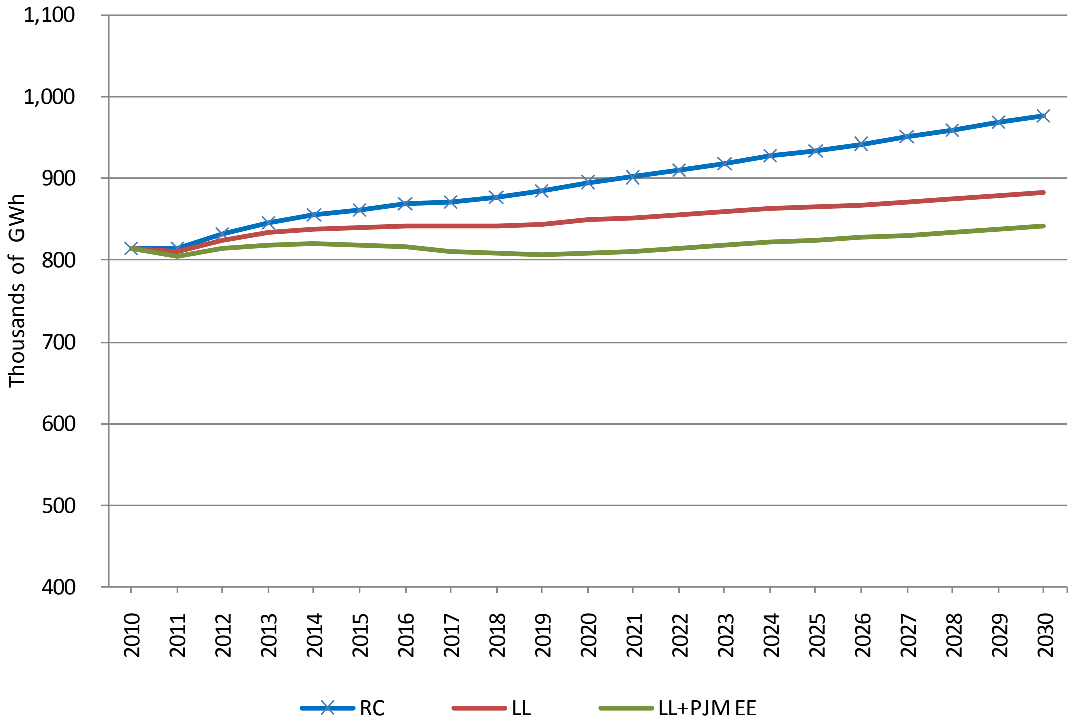
PPRAC members and interested parties requested several additional scenarios to further examine supply options in the State. Where possible, PPRP accommodated those requests. The PPRAC-identified additional alternative scenarios, the results for which are presented in this Chapter, are: Low Loads and PJM-wide Energy Efficiency; Medium Renewables and MSD; Energy Efficiency, High Renewables and MSD; and Coal Plant Life Extension. Note that Appendix L (Supplemental Responsive Scenarios) contains four more scenarios which were developed in response to comments received during public review of the document. The four Responsive Scenarios are: Early Natural Gas Plant, Combined Events, EPA Regulations with Additional Retirements 1 and EPA Regulations with Additional Retirements 2.

13.2 Low Loads plus PJM-Wide Energy Efficiency Alternative Scenario

13.2.1 Introduction

The Low Load plus PJM-wide Energy Efficiency scenario examines the possibility of both low load growth and aggressive energy efficiency and conservation programs throughout the PJM region. The energy efficiency ("EE") scenarios discussed earlier in this report (Chapter 10) only assumed aggressive energy efficiency and conservation programs in Maryland but the "PJM EE" scenario assumes aggressive energy efficiency and conservation in all of the states in PJM that presently have energy efficiency and conservation programs in place. PJM-wide energy efficiency was implemented using the same assumptions for the other PJM states having energy efficiency programs as were applied to Maryland in the EE scenarios. Therefore, all state energy efficiency/conservation program energy consumption reduction goals are fully achieved by 2020 and demand reductions equal to 150 percent of the demand reduction targets are achieved by 2030. The combination of low load growth with PJM-wide EE results in significant load reductions compared to the LTER Reference Case ("RC") loads. Annual energy consumption by 2030 in the Low Load plus PJM-wide EE ("LL+PJM EE") alternative scenario is 13.9 percent lower than the LTER Reference Case and 4.6 percent lower than the Low Load ("LL") alternative scenario (Chapter 8). A comparison of annual energy consumption among the three scenarios (RC, LL, and LL+PJM EE) is shown in Figure 13.1.

Figure 13.1 Comparison of PJM Annual Energy Consumption in the LTER Reference Case and Low Load Scenarios



13.2.2 Capacity Additions

The need for new natural gas capacity in PJM as a whole is drastically reduced relative to the LTER Reference Case in the LL+PJM EE scenario, and the amount of new capacity built falls by 92 percent, from 30,101 MW in the LTER Reference Case to 2,385 MW (see Table 13.1). New natural gas capacity additions in the PJM-SW and PJM-APS zones are also reduced, and no capacity is added in the PJM-MidE zone.[50]

Table 13.1 Cumulative Natural Gas Capacity Additions Through 2030 – Low Load and PJM EE Scenarios (MW)

Scenario	PJM-SW	PJM-MidE	PJM-APS	PJM Total
LTER Reference Case	2,385	1,908	3,816	30,101
Low Load	1,908	0	954	8,109
Low Load + PJM EE	477	0	477	2,385

[50] Note that no new natural gas capacity is added in PJM-MidE under either the Low Load or Low Load plus PJM-wide EE scenarios.

The reduced loads in the LL+PJM EE scenario also increased the level of economic retirements, which were 315 MW in the LTER Reference Case, 300 MW in the Low Load scenarios, and 747 MW in the LL+PJM EE scenario.

Figure 13.2 PJM-SW Natural Gas Capacity Additions – Low Load and PJM EE Scenarios

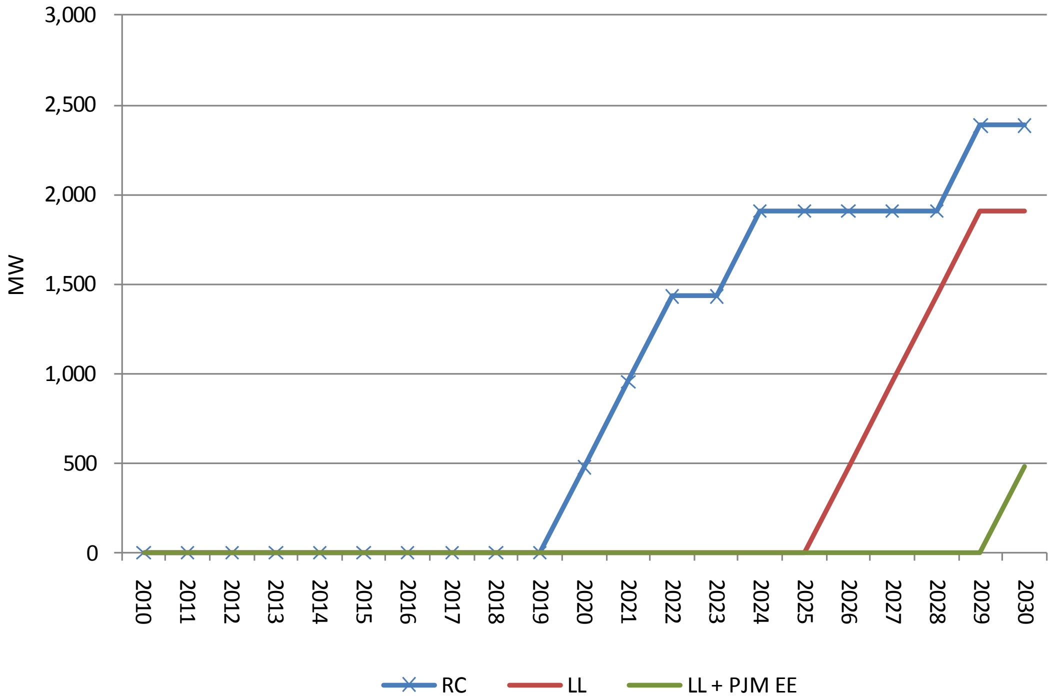
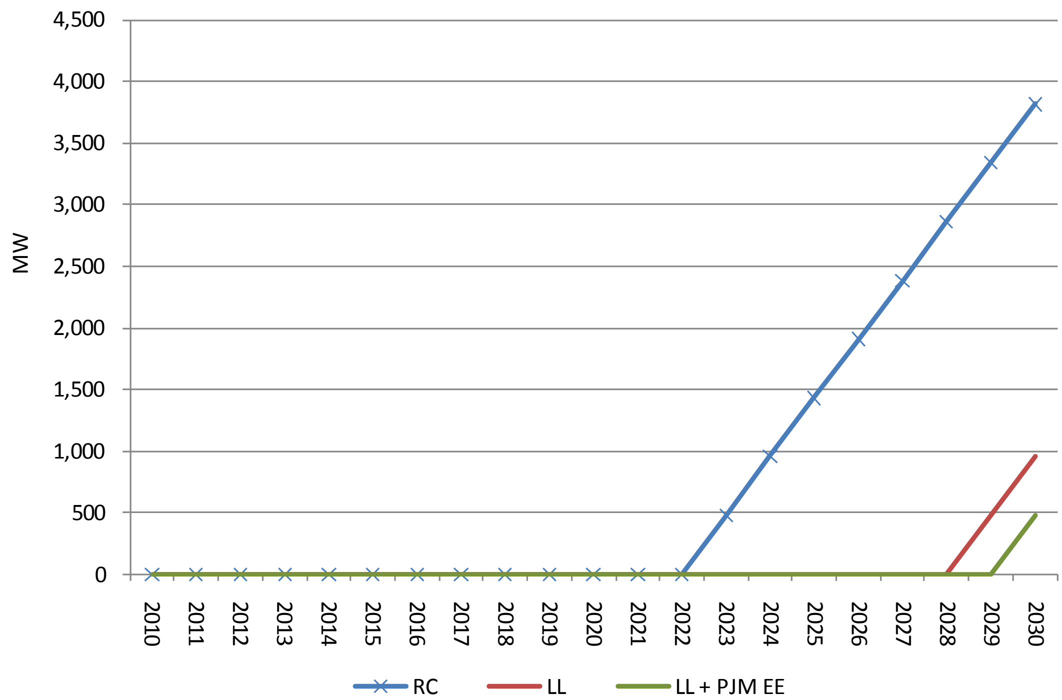


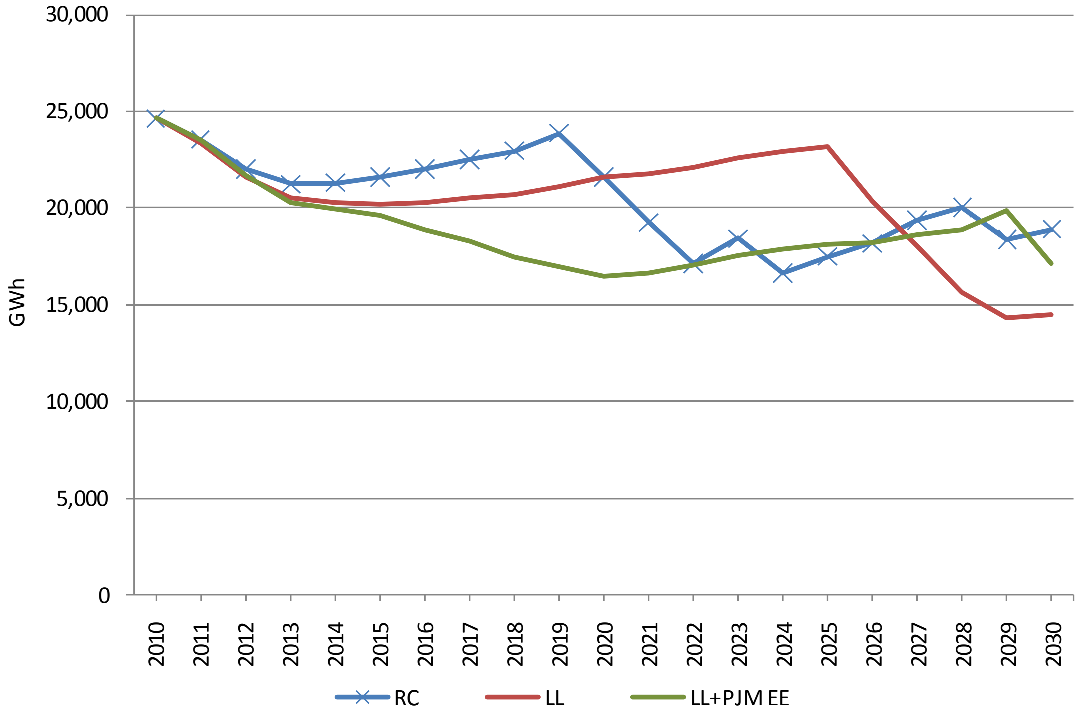
Figure 13.3 PJM-APS Natural Gas Capacity Additions – Low Load and PJM EE Scenarios



13.2.3 Net Imports

The PJM-SW zone's net imports under the LL+PJM EE scenario are initially lower than the LTER Reference Case imports given lower demands, but towards the end of the period, the imports increase because very little capacity is added in PJM-SW (see Figure 13.4). The growth in load under the LL+PJM EE scenario assumptions, while modest, remains positive. A portion of that additional load is served from new generation, and a portion is served through higher net imports relative to the LTER Reference Case.

Figure 13.4 PJM-SW Net Imports – Low Load and PJM EE Scenarios



PJM-MidE net imports under the LL+PJM EE scenario are below both the LTER Reference Case and the Low Load scenario (see Figure 13.5) throughout the study period since no new generating capacity is constructed in PJM-MidE. Any increase in load levels needs to be served through increases in imports to the zone.

Net imports in the PJM-APS zone decline through 2022 in the two low load scenarios (i.e., net exports increase). Additionally, since energy consumption is lower throughout PJM, the PJM-APS zone's exports are lower than shown for the LTER Reference Case in both the Low Load and LL+PJM EE scenarios (see Figure 13.5).

Figure 13.5 PJM-MidE Net Imports – Low Load and PJM EE Scenarios

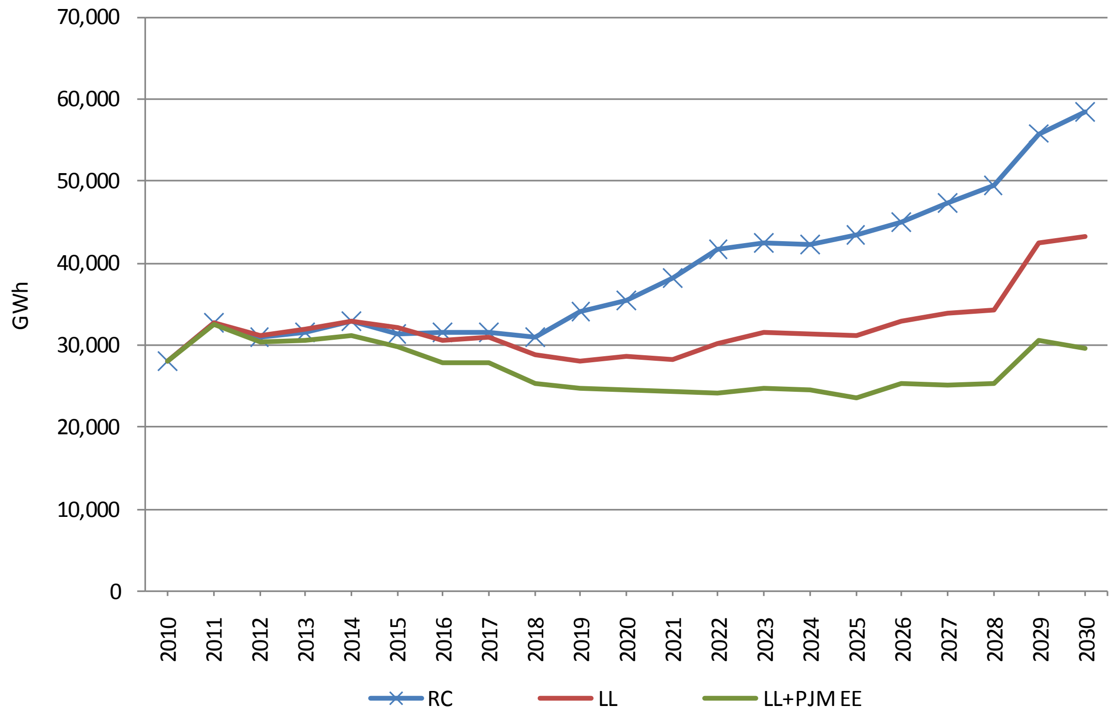
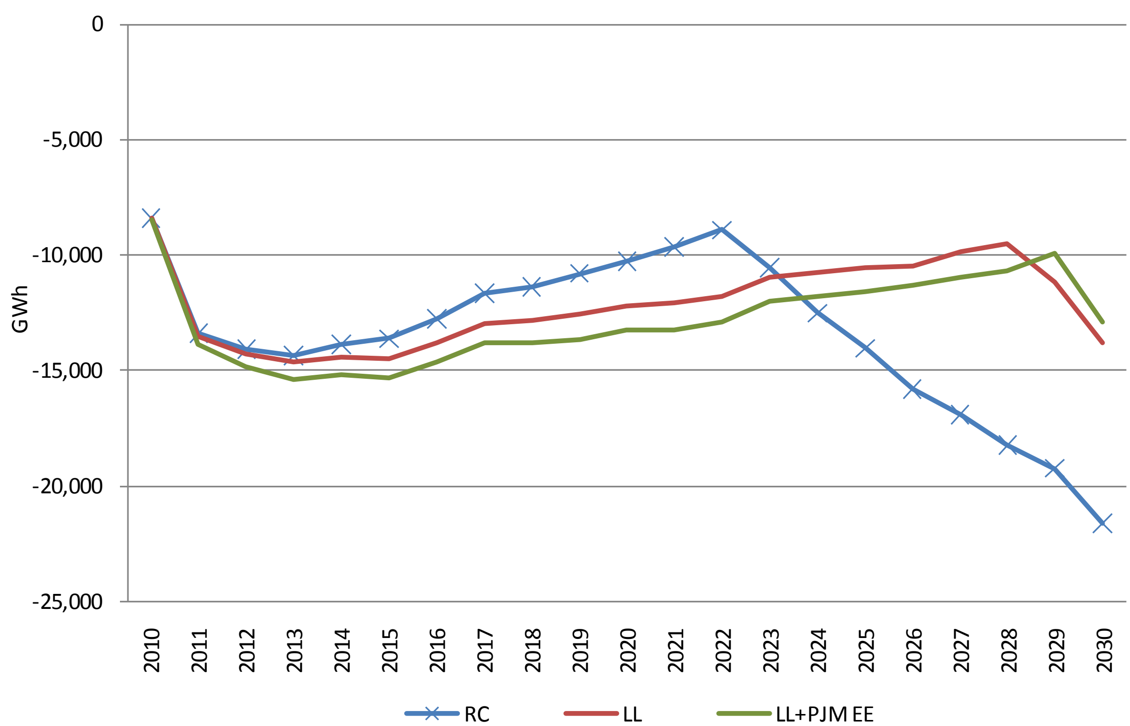


Figure 13.6 PJM-APS Net Imports – Low Load and PJM EE Scenarios



13.2.4 Fuel Use

Table 13.2 shows the coal and natural gas usage in Maryland for electricity generation. Coal consumption in the LL+PJM EE scenario is initially below the Low Load and LTER Reference Case but coal plants in Maryland increase their capacity factors in 2030, the last year of the forecast period. Natural gas use in the state is also significantly lower because the PJM-SW zone adds no new natural gas capacity until 2030. In the Ventyx model, the lower load levels associated with aggressive energy efficiency and conservation programs affect natural gas consumption much more than coal consumption.

Table 13.2 Fuel Use for Electricity Generation in Maryland in 2030 - Low Load and PJM EE Scenarios

Scenario	Coal (mmBtu)	Natural Gas (mmBtu)
LTER Reference Case	292,159,864	93,701,484
Low Load	291,856,002	70,345,273
Low Load + PJM EE	291,404,459	17,207,543

13.2.5 Energy Prices

The load sensitivity discussion presented in Chapter 8 explained that while low load growth initially resulted in reduced wholesale energy prices, by 2030 prices were slightly higher than under the LTER Reference Case load growth assumptions, other factors held constant. The same general dynamic occurs in the LL+PJM EE scenario but to a more extreme degree. For example, in the PJM-SW region, when lower loads reduce the need to operate more expensive generation units through 2026, which has the effect of reducing wholesale energy prices (see Figure 13.7). However, in both the Low Load and LL+PJM EE scenario, fewer efficient new natural gas units are built, making prices higher than in the LTER Reference Case in later years of the study period because the generation fleet is less efficient on average.

Note that the wholesale energy prices shown in Figure 13.7 do not include the costs of implementing energy efficiency and conservation programs in Maryland and throughout PJM. These program-related costs in the LL+PJM EE scenario are also significantly greater than those in the EE scenarios because under the LL+PJM EE scenario, we assume more aggressive energy efficiency and conservation in PJM as a whole rather than just in Maryland. Therefore, wholesale energy prices and capacity prices alone do not present a complete accounting of the costs of the Low Load plus PJM-wide EE scenario.

Prices in PJM-MidE (Figure 13.8) and PJM-APS (Figure 13.9) follow the same pattern as PJM-SW for the same reasons as explained in reference to the PJM-SW zone.

Figure 13.7 PJM-SW Real All-Hours Energy Price – Low Load and PJM EE Scenarios

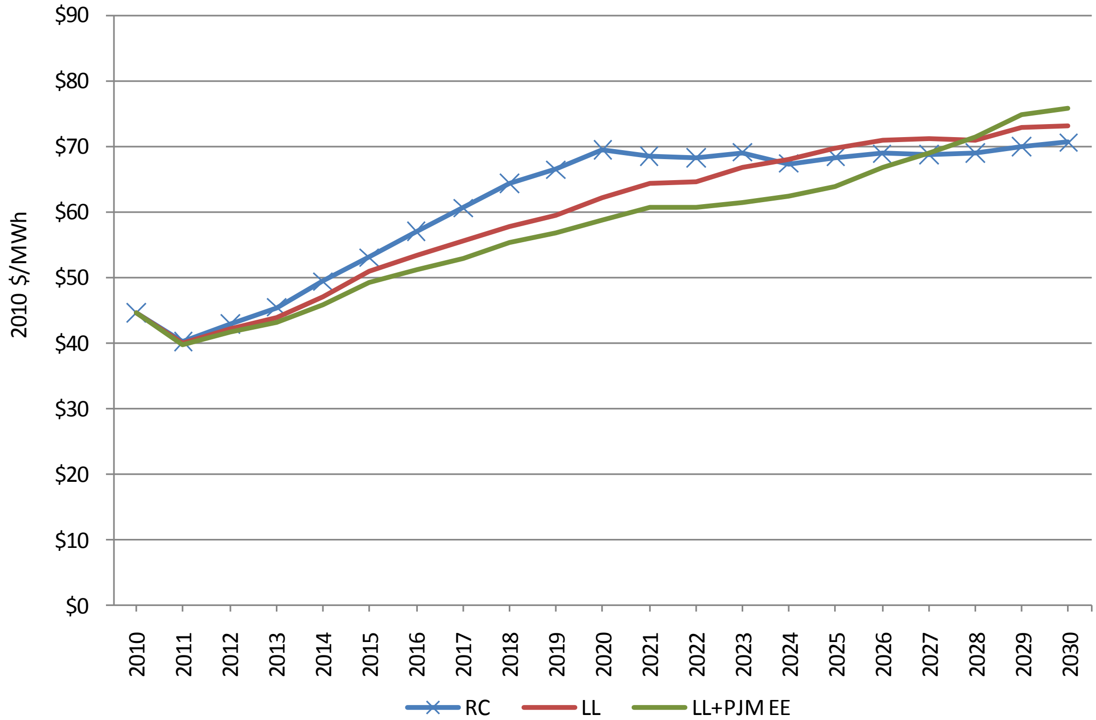


Figure 13.8 PJM-MidE Real All-Hours Energy Price – Low Load and PJM EE Scenarios

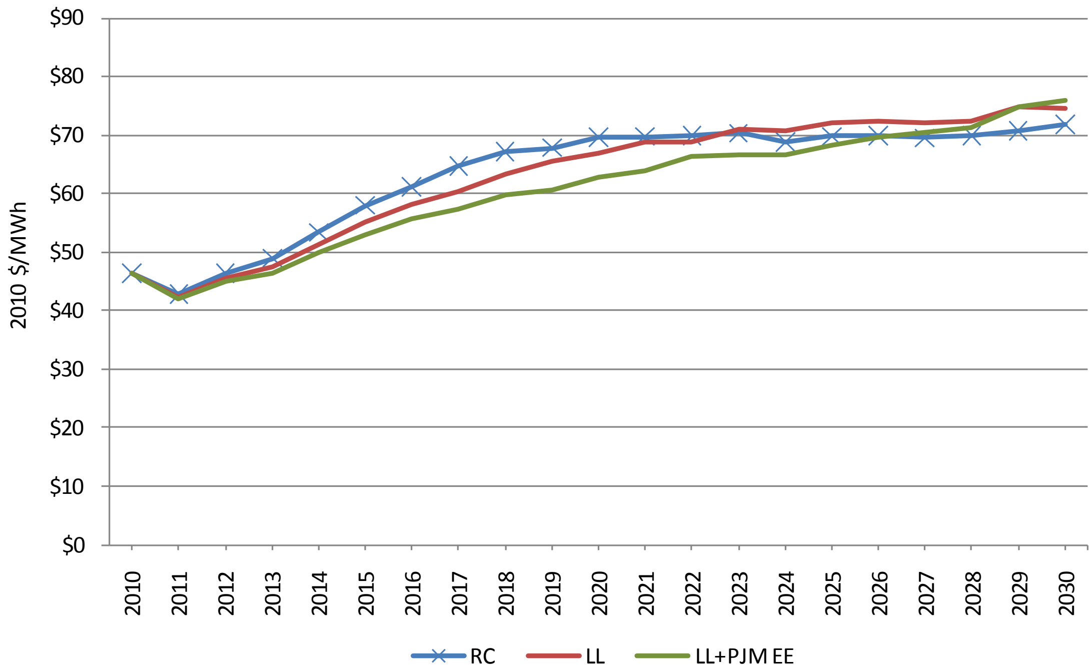
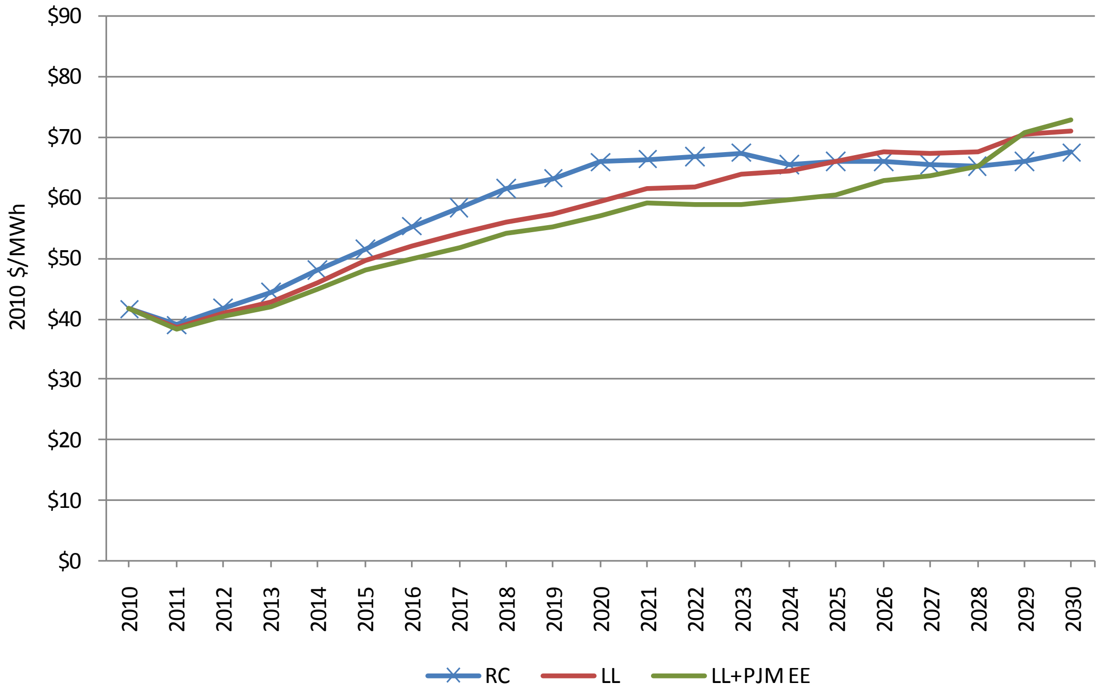


Figure 13.9 APS prices Real All-Hours Energy Price – Low Load and PJM EE Scenarios

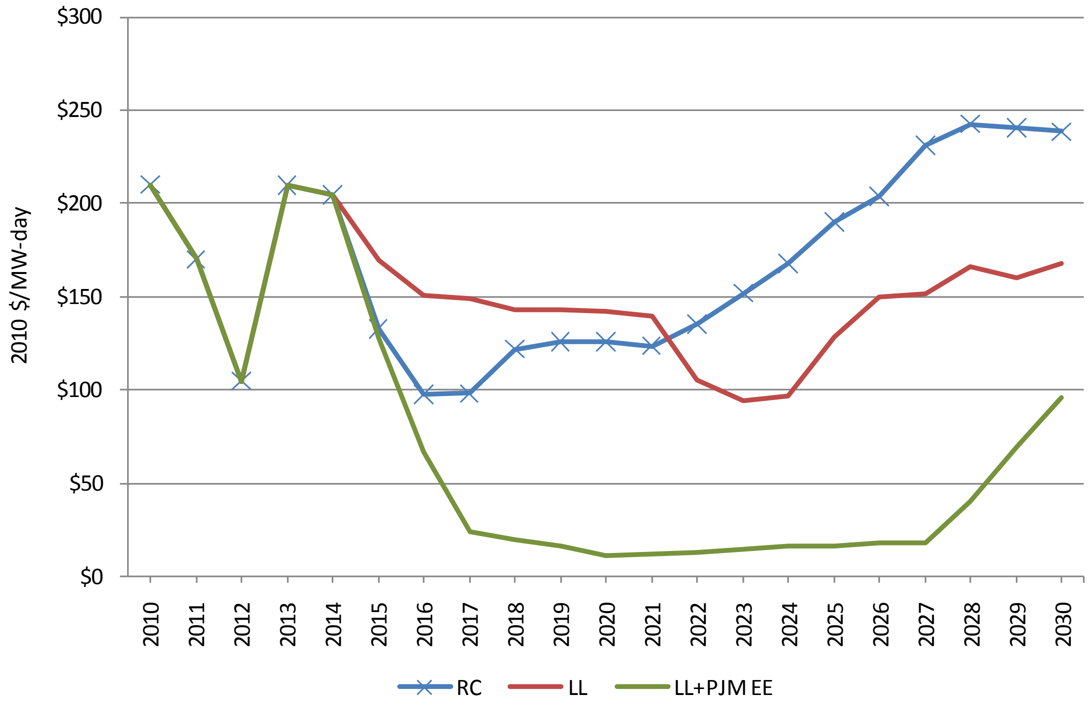


It should be noted that although the wholesale energy prices under the Low Load and LL+PJM EE scenarios are higher than under the LTER Reference Case, the total number of MWh being purchased is lower than the LTER Reference Case. Hence, total expenditures on electricity are reduced relative to the LTER Reference Case.

13.2.6 Capacity Prices

Given that loads are reduced in the LL+PJM EE scenario, so too is the demand for generation and generating reserves. As a result, the capacity prices in all three Maryland zones are lower in the LL+PJM EE scenario than either the LTER Reference Case or the Low Load scenario. PJM-SW prices are below $50/MW-day, indicating a capacity surplus, until 2027 and increase moderately towards the end of the period when load growth absorbs the zone's existing capacity.

Figure 13.10 PJM-SW Capacity Prices – Low Load and PJM EE Scenarios



Capacity prices in the PJM-MidE zone under the LL+PJM EE scenario are similar to the Low Load scenario, and are slightly higher between 2023 and 2026 because energy prices are lower. Lower energy prices put upward pressure on capacity prices as new plant construction requires sufficient revenue to cover the cost of entry (Figure 13.11).

Capacity prices in the PJM-APS region generally remain below $50/MW-day in the LL+PJM EE scenario throughout the forecast period because with the reduced loads, the region has ample generation and generating reserves through 2030, the terminal year of the analysis period (Figure 13.12).

Figure 13.11 PJM-MidE Capacity Prices – Low Load and PJM EE Scenarios

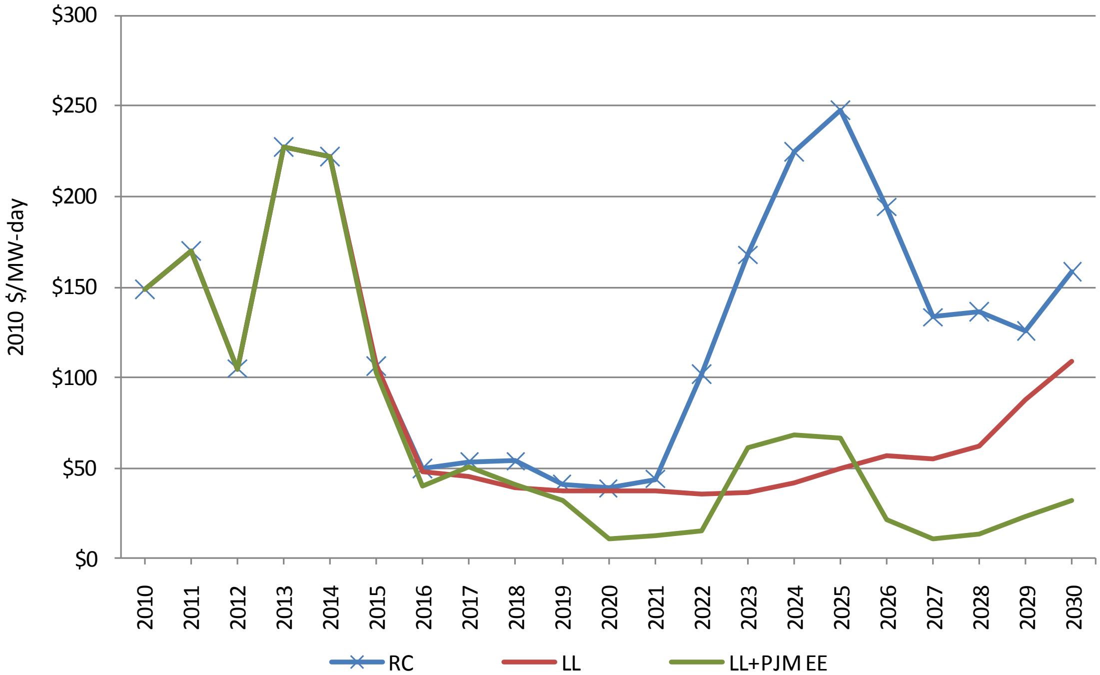
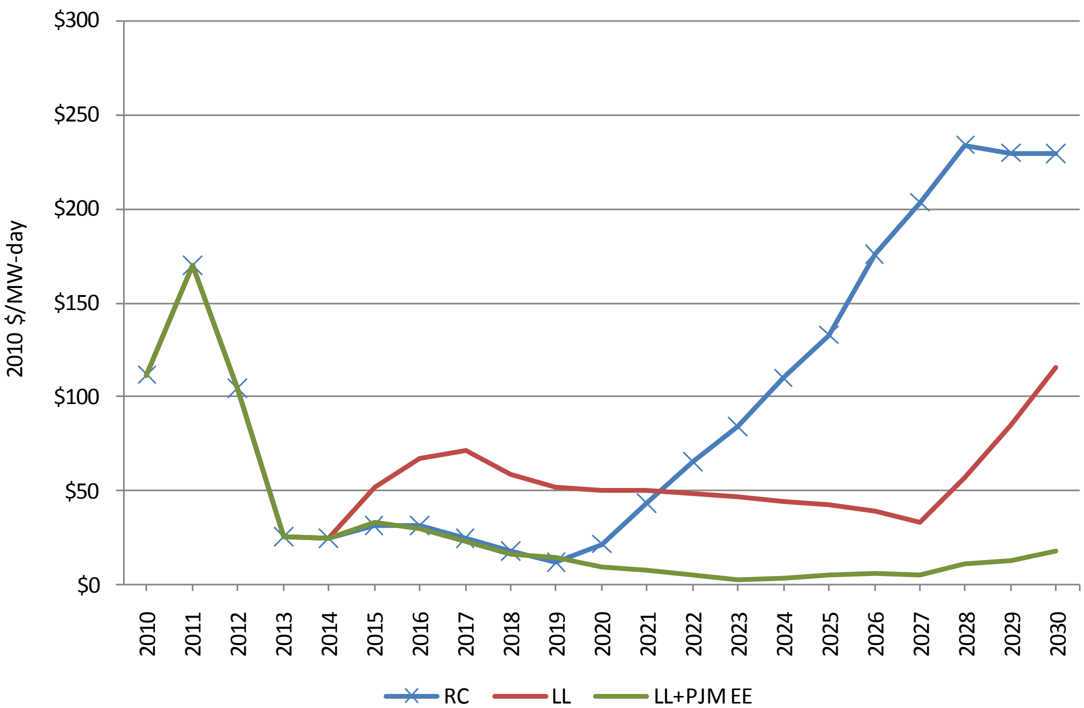


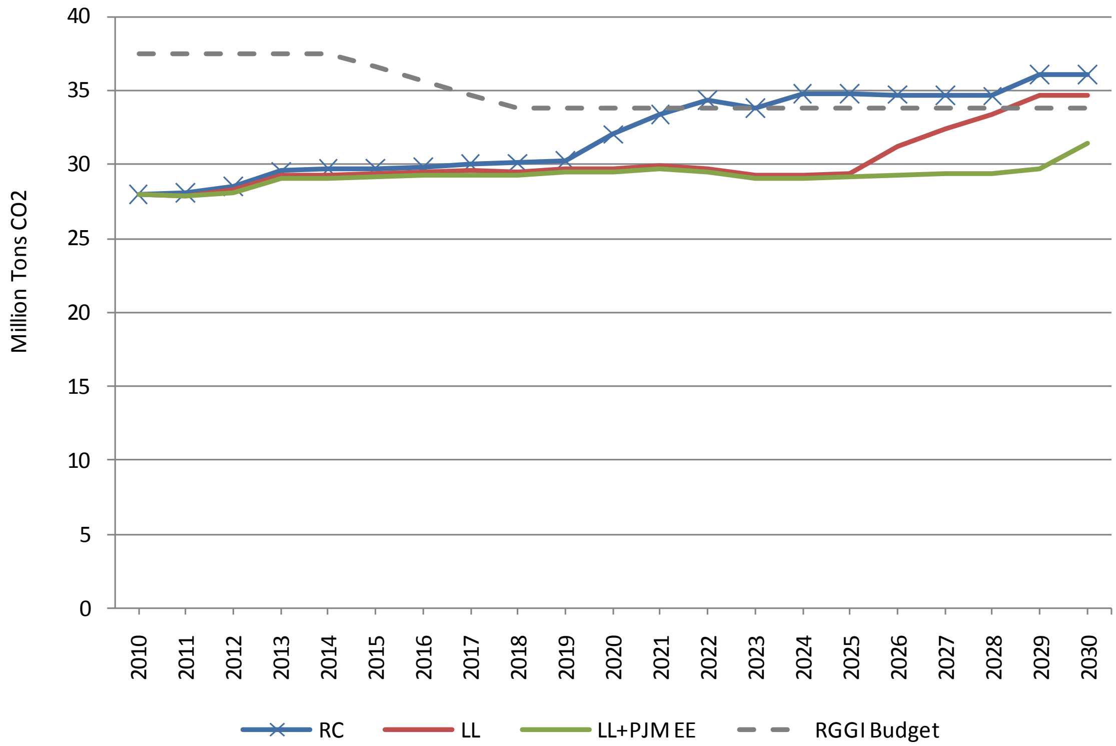
Figure 13.12 PJM-APS Capacity Prices – Low Load and PJM EE Scenarios



13.2.7 Emissions

Figure 13.13 presents the CO_2 emissions under the LTER Reference Case, Low Load, and LL+PJM EE scenarios, along with the RGGI budget. Introducing both low load growth and energy efficiency significantly reduces emissions from Maryland generation. Under the Low Load scenario, emissions increase after 2026 as new capacity is added but since new capacity is not added until 2030 in the LL+PJM EE scenario, CO_2 emissions remain low and constant and do not increase until the last year of the study period. Under the LL+PJM EE scenario assumptions, CO_2 emissions remain below Maryland's RGGI budget through at least 2030.

Figure 13.13 Maryland Electric Generation CO_2 Emissions – Low Load and PJM EE Scenarios[51]



[51] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

13.2.8 Results

The key results of the Low Load + PJM EE scenario are as follows:

- The combination of low load growth and PJM-wide energy efficiency reduces the need for new generation capacity in PJM by 92 percent – from 30,101 MW to 2,385 MW.
- Maryland emissions from generation under the LL+PJM EE scenario are below the LTER Reference Case scenario because coal plants in the State do not increase output until 2027 and only one combined cycle natural gas unit is built in 2030.
- Wholesale energy prices are generally lower in the LL+PJM EE scenario than in the LTER Reference Case until the last few years of the study period. The costs of achieving PJM-wide energy efficiency and conservation savings, however, are not incorporated in the wholesale energy prices (or capacity prices) shown.

13.3 Medium Renewables plus MSD Alternative Scenario

13.3.1 Introduction

The EO tasked PPRP with investigating, among other things, alternative supply options. To address this, PPRP first considered two different levels of renewable generation capacity; the level of renewable energy generation included in the LTER Reference Case, and as an alternative, the levels of renewable energy generation assumed under the High Renewables (“HREN”) scenarios. The Medium Renewables scenario presents a third level of new investment in renewable generating capacity that lies between the LTER Reference Case and High Renewables scenarios assumptions, and includes the Mt. Storm to Doubs transmission upgrade (“MREN+MSD”). This section compares the MREN+MSD scenario to the corresponding HREN and LTER Reference Case scenarios that also include the Mt. Storm to Doubs transmission upgrade as seen in previous chapters (HREN+MSD and MSD, respectively).

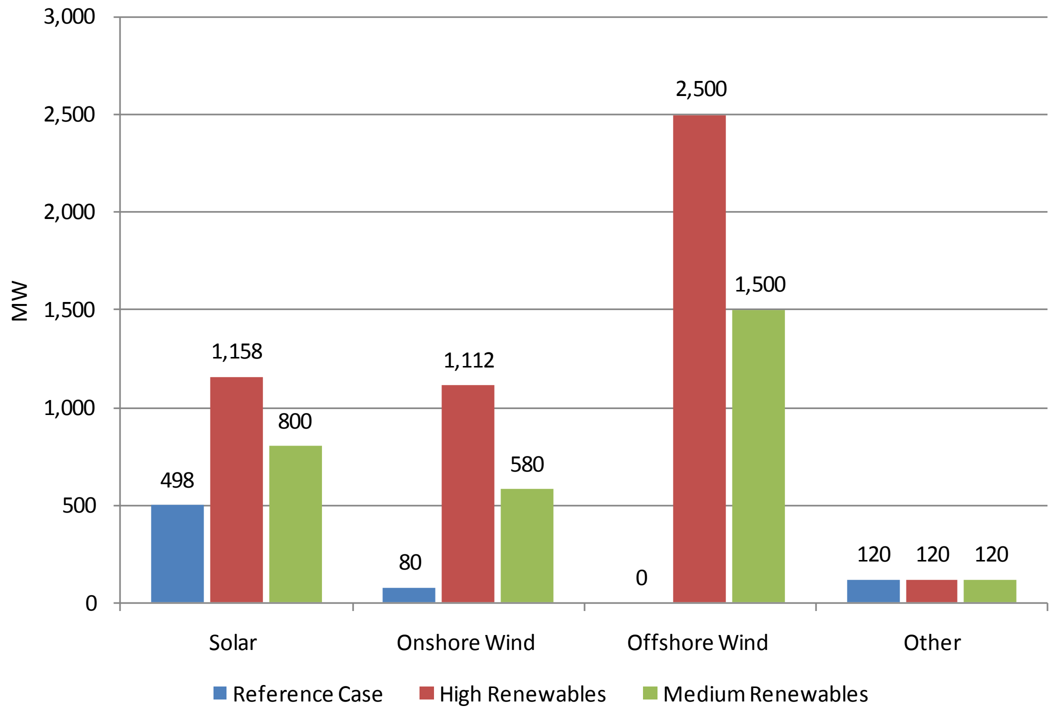
13.3.2 Renewable Capacity Additions

The LTER Reference Case assumes that 698 MW of renewable capacity is installed in Maryland while the High Renewables scenarios presented in Chapter 9 involved a total of 4,491 MW of renewable capacity in the State. Given that the HREN scenario can be viewed as aggressive, the MREN+MSD scenario presents a middle ground and assumes that 3,000 MW of new renewable generating capacity is developed in Maryland over the 20-year study period.

Figure 13.14 shows renewable generating capacity under the LTER Reference Case and the High and Medium renewable energy scenarios for the year 2030. Under MREN+MSD, 800 MW of solar, 580 MW of on-shore wind, and 1,500 MW of off-shore wind is constructed in

Maryland by 2030. The biomass and landfill gas (Other) assumptions are unchanged from the LTER Reference Case, with 40 MW and 80 MW installed by 2030, respectively.

Figure 13.14 2030 Renewable Energy Generation Capacity Levels



The MREN+MSD scenario accelerates the pace of renewable capacity construction relative to the LTER Reference Case. Table 6.1 shows that under the HREN assumptions, the State adds 985 MW by 2020 but under the MREN+MSD scenario, 1,414 MW is added. The MREN+MSD assumes that the first 500 MW off-shore wind capacity, which is located in the PJM-MidE zone, comes online in 2017, which is four years earlier than in the HREN scenarios. However, by 2030, off-shore wind capacity in the MREN+MSD is 1,500 MW, which is 1,000 below the assumed capacity by the same year in the HREN scenarios.

Table 13.3 Generic Renewable Capacity in Maryland Across Renewable Scenarios (MW)

Year	LTER Reference Case	Medium Renewables	High Renewables
2015	494	494	494
2020	645	1,414	985
2025	672	2,226	2,819
2030	698	3,000	4,891

Note: Figures do not include existing or planned renewable generating capacity in Maryland, which totals 244 MW.

Table 6.2 shows the cumulative renewable capacity by year in the MREN+MSD scenario. As in the HREN scenarios, the off-shore wind is constructed off of Maryland's Eastern Shore in the PJM-MidE zone.

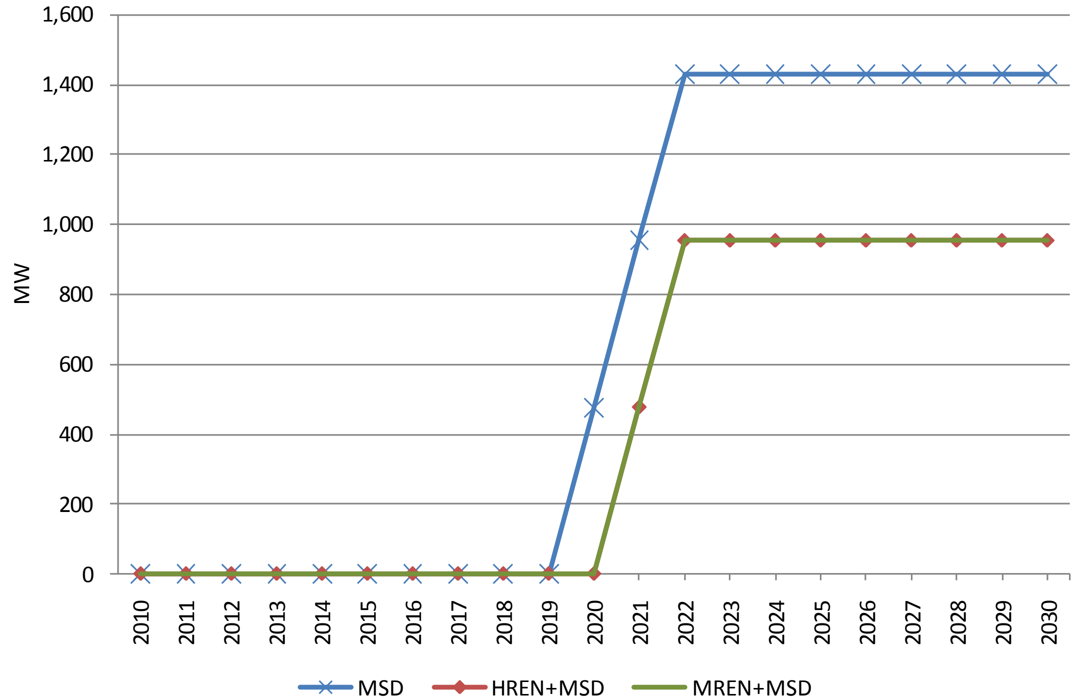
Table 13.4 Cumulative Natural Gas Capacity Additions – Medium Renewables Scenario (MW)

Year	Solar	On-shore Wind	Off-shore Wind	Other
2010	0	0	0	0
2011	30	80	0	0
2012	130	80	0	120
2013	201	80	0	120
2014	247	80	0	120
2015	294	80	0	120
2016	341	130	0	120
2017	387	130	500	120
2018	433	180	500	120
2019	444	180	500	120
2020	564	230	500	120
2021	701	230	500	120
2022	767	280	1,000	120
2023	767	280	1,000	120
2024	776	330	1,000	120
2025	776	330	1,000	120
2026	784	380	1,000	120
2027	784	430	1,500	120
2028	792	480	1,500	120
2029	792	530	1,500	120
2030	800	580	1,500	120

13.3.3 Natural Gas Capacity Additions

Figure 13.15 presents the cumulative natural gas capacity additions in the MSD, MREN+MSD, and HREN+MSD scenarios for PJM-SW. Three combined cycle plants are constructed in PJM-SW in the MSD scenario. Adding additional renewable capacity to the region reduces the requirement to only two combined cycle units, that is, in both the MREN+MSD and HREN+MSD scenarios, a single combined cycle plant is displaced in Maryland by renewable generating capacity.

Figure 13.15 PJM-SW Natural Gas Capacity Additions – Medium Renewables Scenario



The accelerated development of off-shore wind in PJM-MidE under the MREN+MSD scenario delays the need for a new combined cycle unit by approximately two years compared to the MREN+MSD scenario but by the end of the period, the two scenarios only differ by a single combined cycle unit (see Figure 13.16). Additionally, the MSD scenario (with the renewable builds assumed in the LTER Reference Case) involves no combustion turbine units in PJM-MidE while both the MREN+MSD and HREN+MSD scenarios require two combustion turbine units. While the LTER does not serve as a wind integration study, this result suggests that adding intermittent resources, such as off-shore wind, increases the need for fossil-fueled peaking capacity.

Figure 13.16 PJM-MidE Natural Gas Capacity Additions – Medium Renewables Scenario

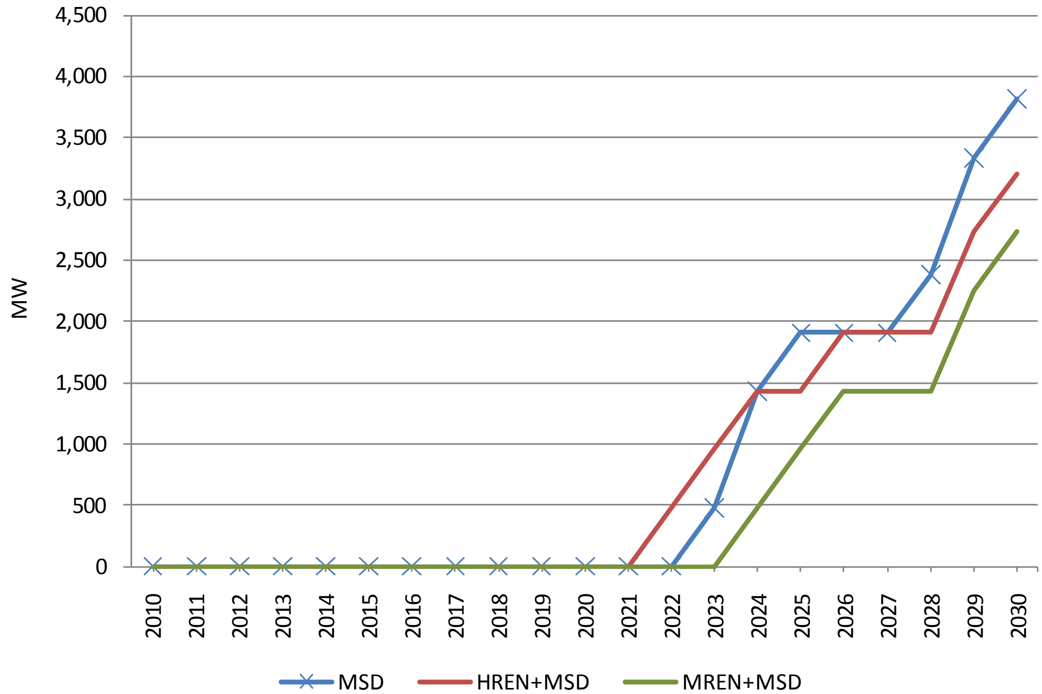
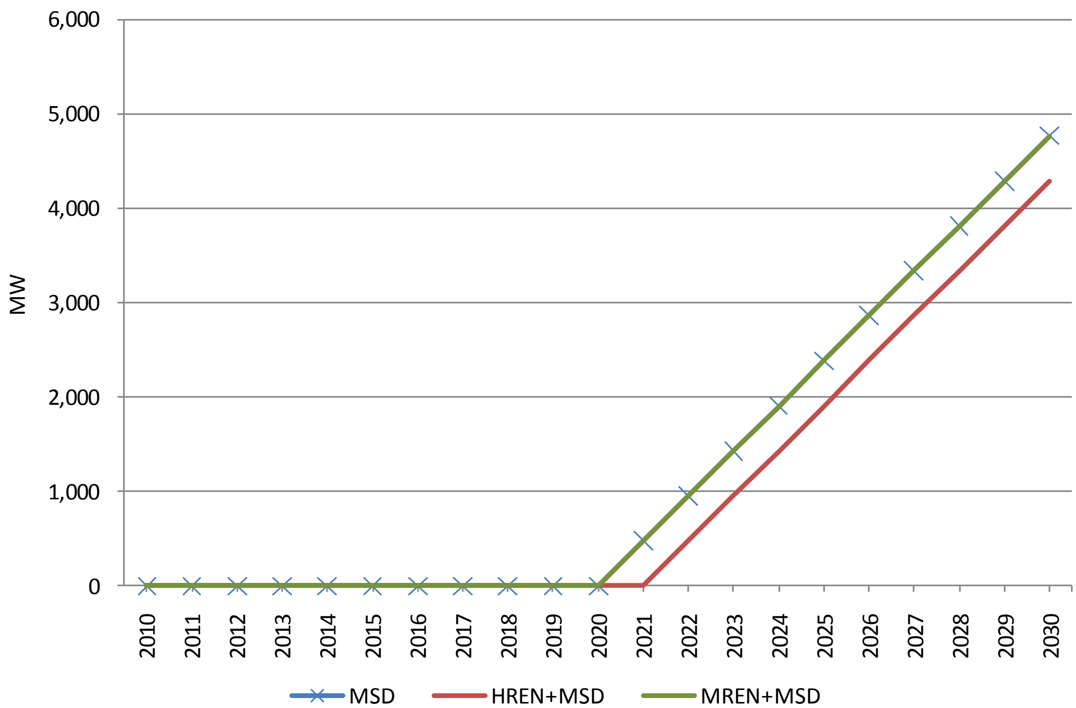


Figure 13.17 PJM-APS Natural Gas Capacity Additions – Medium Renewables Scenario

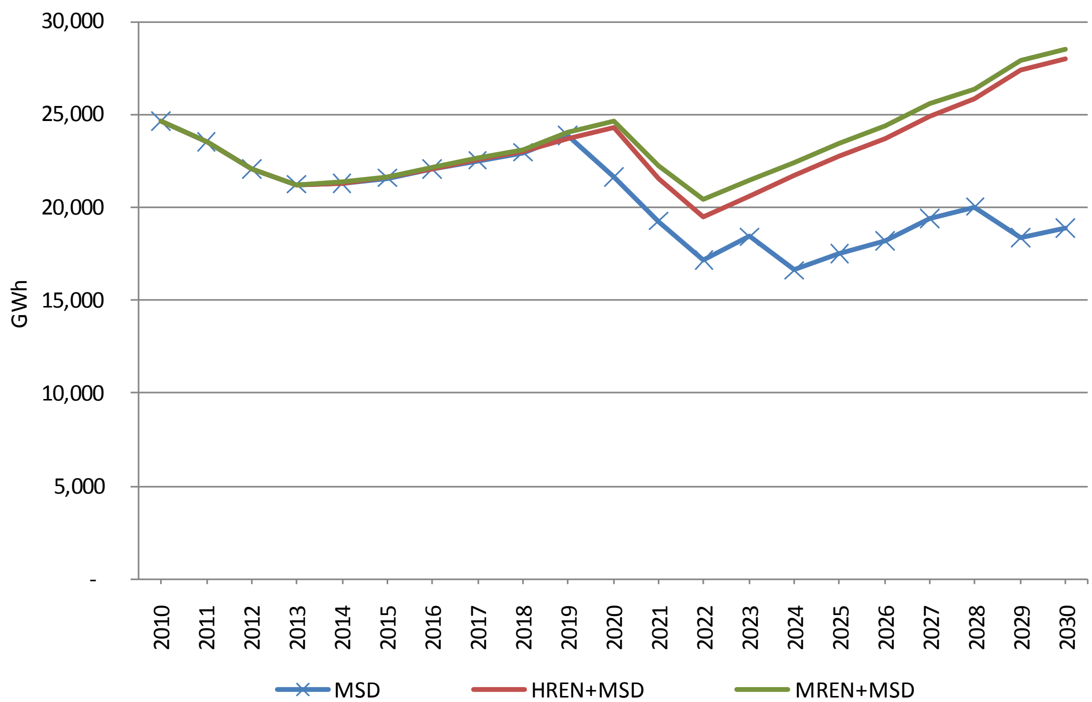


As is often the case with the lower-cost PJM-APS zone, neither the medium or high renewable capacity additions have a significant impact on the generic gas builds (Figure 13.17).

13.3.4 Net Energy Imports

Adding additional renewable generation capacity to the three Maryland zones affects the net imports in each zone. Figure 6.5 shows that net imports in PJM-SW under the HREN+MSD and MREN+MSD scenarios are very similar and approximately 50 percent higher than the MSD scenario in 2030. The increased PJM-SW net imports are a consequence of the additional off-shore wind capacity in PJM-MidE and lower natural gas capacity additions in PJM-SW.

Figure 13.18 PJM-SW Net Imports – Medium Renewables Scenario



In PJM-MidE (Figure 6.6), net imports are initially slightly lower in the MREN+MSD scenario as compared to the MSD and HREN+MSD scenarios because the first 500 MW of off-shore wind comes online in 2017, four years before the first off-shore installation in the HREN+MSD scenario. In the second half of the forecast period, PJM-MidE net imports in the MREN+MSD scenario lie between the MSD and HREN+MSD, which is expected because the renewable capacity in this scenario lies between the MSD and HREN+MSD scenarios. Greater levels of renewable energy generation in PJM-MidE result in lower levels of imported energy needed to serve load in that zone.

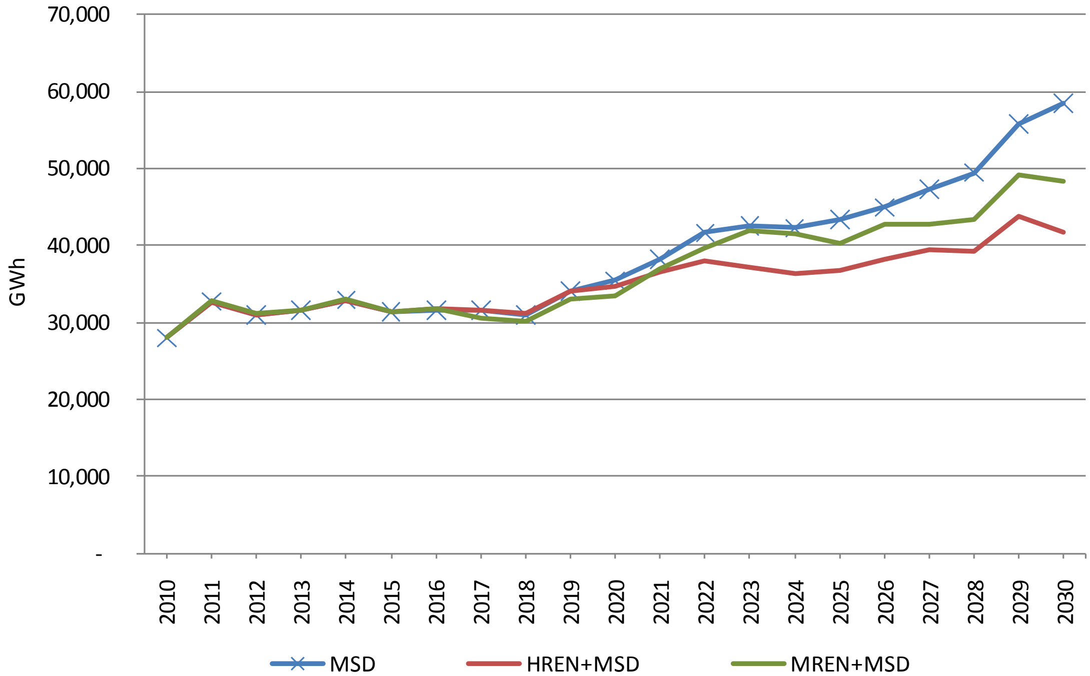
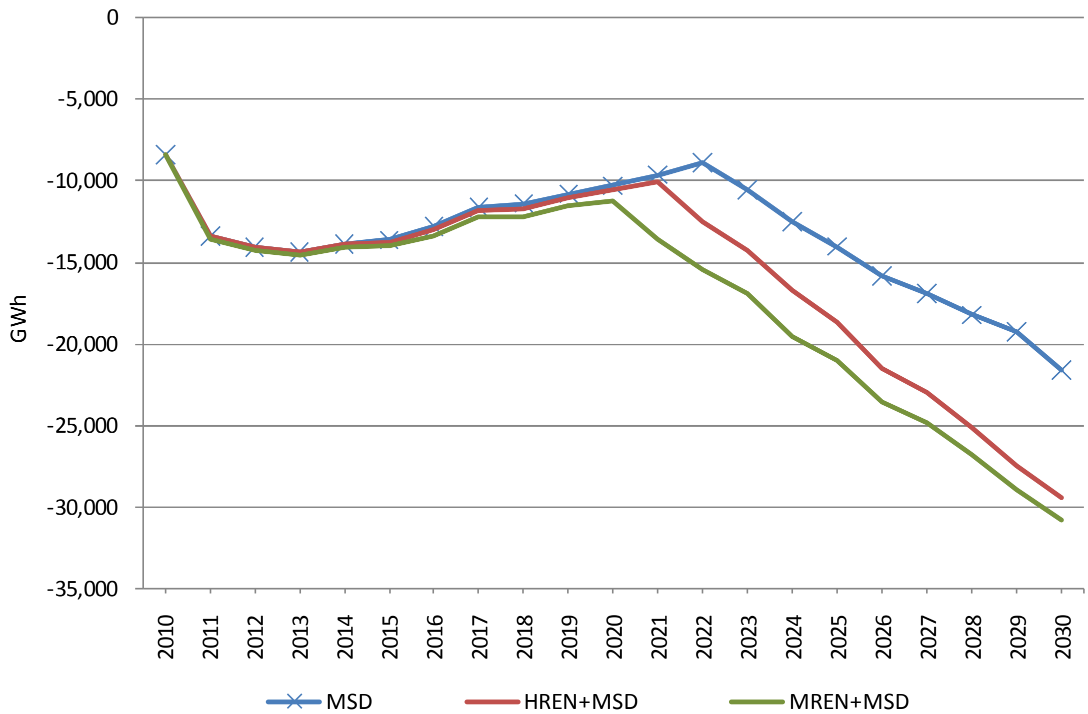


Figure 6.7 presents net imports in the PJM-APS zone, which are greatest in the MREN+MSD scenario. In the HREN+MSD scenario, one less combined cycle natural gas plant is constructed in PJM-APS relative to MSD and MREN+MSD scenarios. This inhibits the PJM-APS zone from exporting as much energy as is the case in the MREN+MSD scenario. The additional renewable energy capacity in the MREN+MSD scenario relative to the MSD scenario results in increased energy exports from PJM-APS in the MREN+MSD scenario.

Figure 13.20 PJM-APS Net Imports – Medium Renewables Scenario



13.3.5 Fuel Use

Adding renewable generation to the Maryland regions delays the need to increase the capacity factors of the coal plants by one year (see Figure 6.8). However, coal consumption in the MSD, MREN+MSD, and HREN+MSD scenarios are equal after 2020, which means that adding additional renewable capacity does not displace coal generation in Maryland. Instead, as seen in Figure 6.9, the generation from the additional renewable resources displaces natural gas generation.

Natural gas consumption in Maryland is largely a function of the natural gas builds and since the MREN+MSD and HREN+MSD scenarios involve the same natural gas capacity additions, which are lower than in the MSD scenario, natural gas usage in the MREN+MSD and HREN+MSD scenarios largely track each other (see Figure 6.9). These results suggest that the additional renewable capacity in the MREN+MSD and HREN+MSD scenarios displaces the need for incremental natural gas capacity.

Figure 13.21 Coal Use for Electricity Generation in Maryland – Medium Renewables Scenario

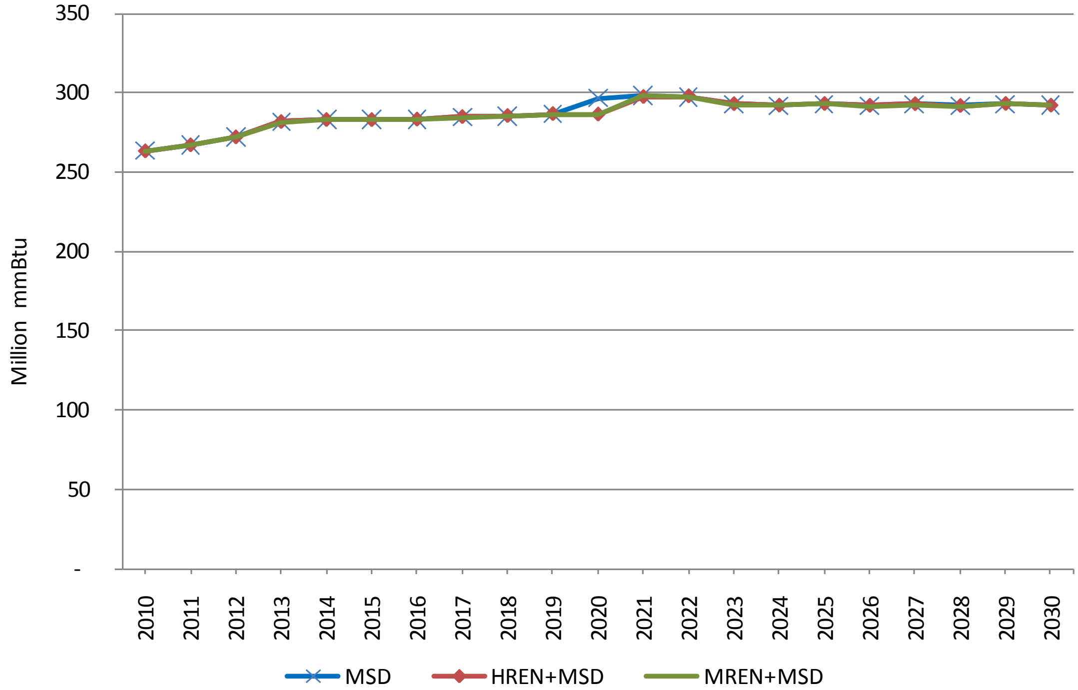
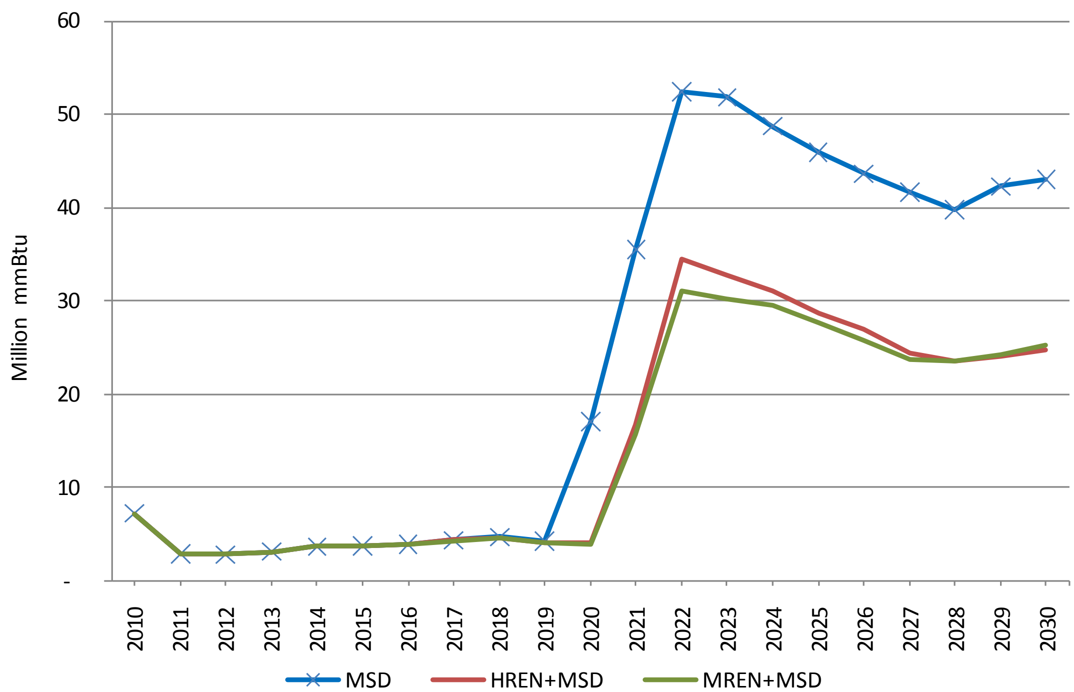


Figure 13.22 Natural Gas Use for Electricity Generation in Maryland – Medium Renewables Scenarios



13.3.6 Energy Prices

The Ventyx model dispatches intermittent renewable resources such as wind and solar first, and then dispatches conventional resources (e.g., coal, nuclear, and natural gas) to meet the remaining load (often referred to as "net load"). The incremental renewable resources added in the HREN+MSD and MREN+MSD scenarios are not the marginal units in the dispatch order and hence do not set wholesale energy market prices. The renewable capacity does reduce the net load that conventional resources must satisfy, but the level of displacement is not sufficient enough to materially change the average all-hours price in each year. As such, the energy price impacts associated with increased renewable energy development (in 2010 dollars) for the PJM-SW, PJM-MidE, and PJM-APS zones are minimal (see Figure 6.10, Figure 6.11, and Figure 6.12).

Figure 13.23 PJM-SW Real All-Hours Energy Price – Medium Renewables Scenarios

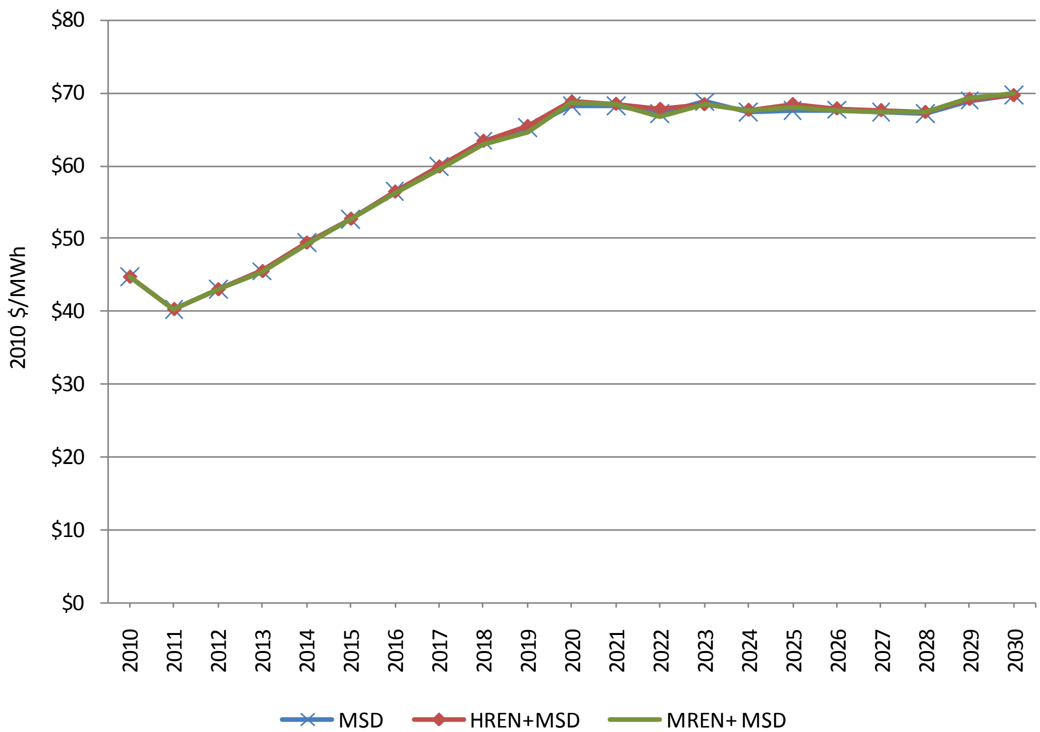


Figure 13.24 PJM-MidE Real All-Hours Energy Price – Medium Renewables Scenarios

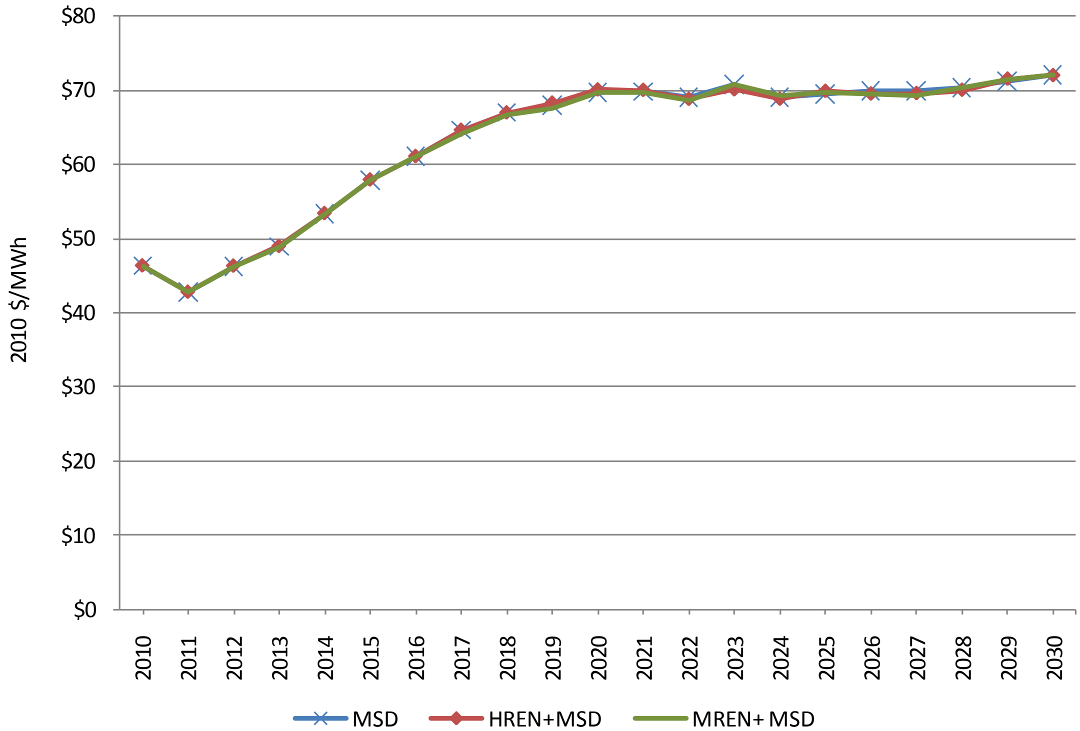
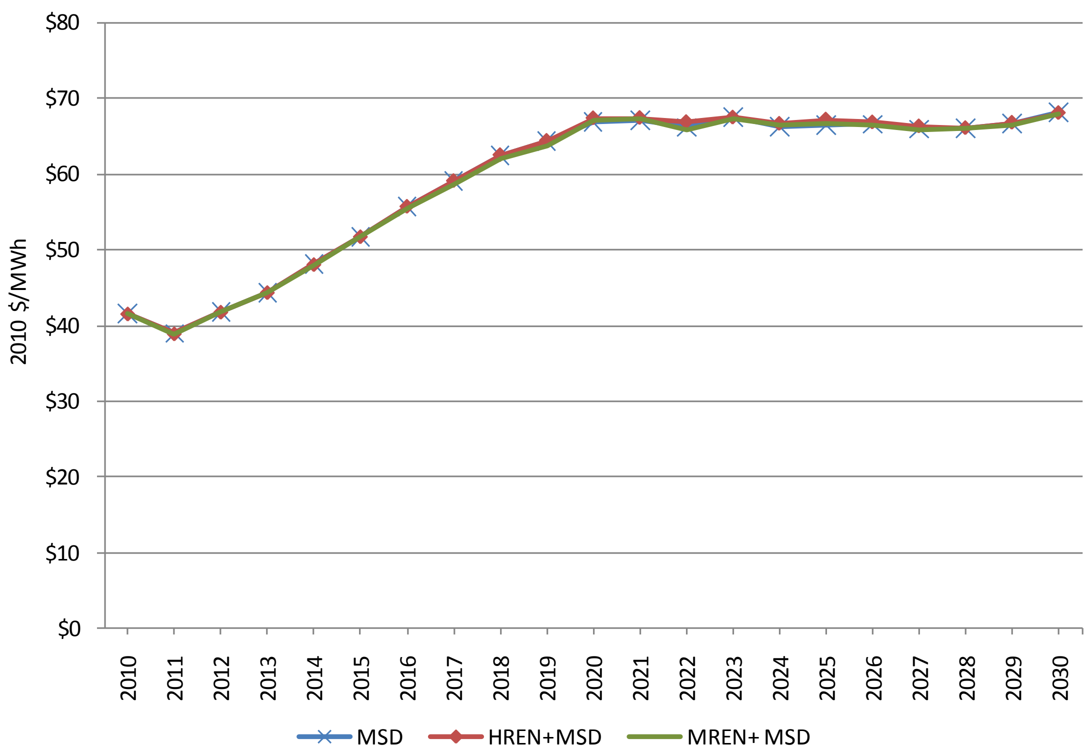


Figure 13.25 PJM-APS Real All-Hours Energy Price – Medium Renewables Scenarios



13.3.7 Capacity Prices

Capacity prices in PJM-SW (Figure 6.13) are not significantly affected by the incremental renewable capacity and the modest differences are mostly driven by the schedule of natural gas plant builds. Figure 6.14 shows the capacity prices in the PJM-MidE area, which are affected by the additional renewable capacity, as all of the off-shore wind capacity – 1,500 MW in MREN+MSD and 2,500 in the HREN+MSD – is built in the PJM-MidE zone. Additionally, a portion of the on-shore wind capacity is assumed to be located in the PJM-MidE zone. PJM-MidE capacity prices are initially lower in the MREN+MSD scenario but the prices in the three scenarios converge by 2030. Capacity prices in PJM-APS, shown in Figure 6.15, are largely unchanged by the renewable capacity.

Figure 13.26 PJM-SW Capacity Prices – Medium Renewables Scenario

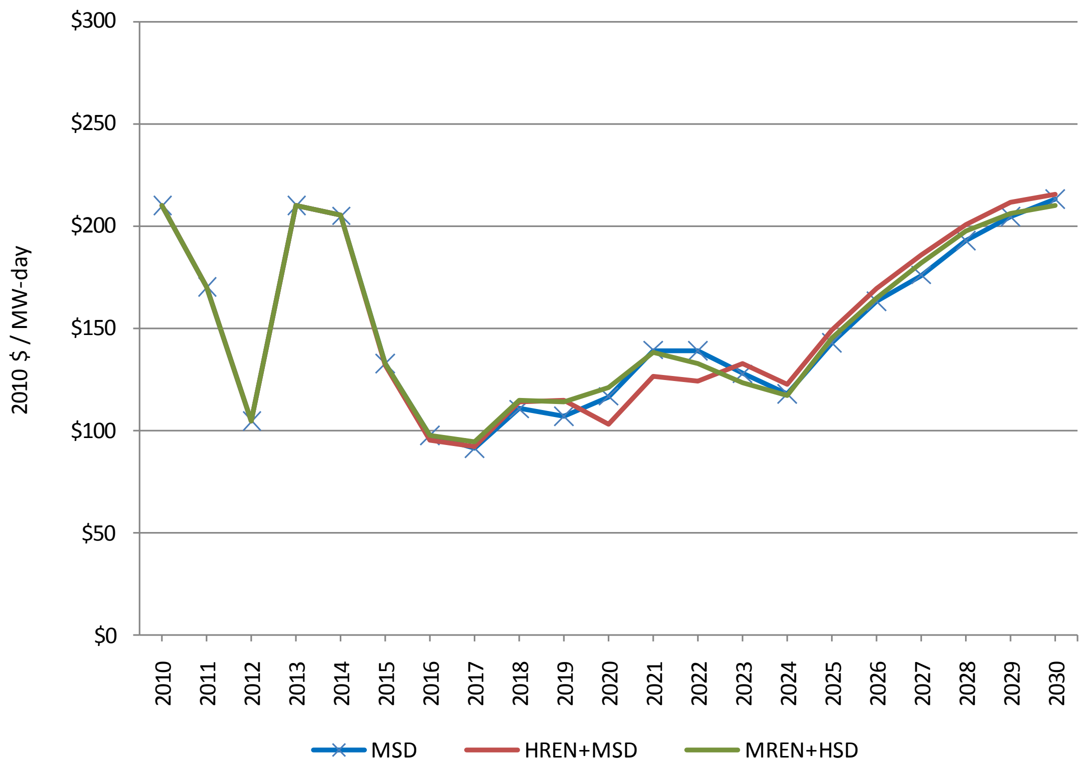


Figure 13.27 PJM-MidE Capacity Prices – Medium Renewables Scenario

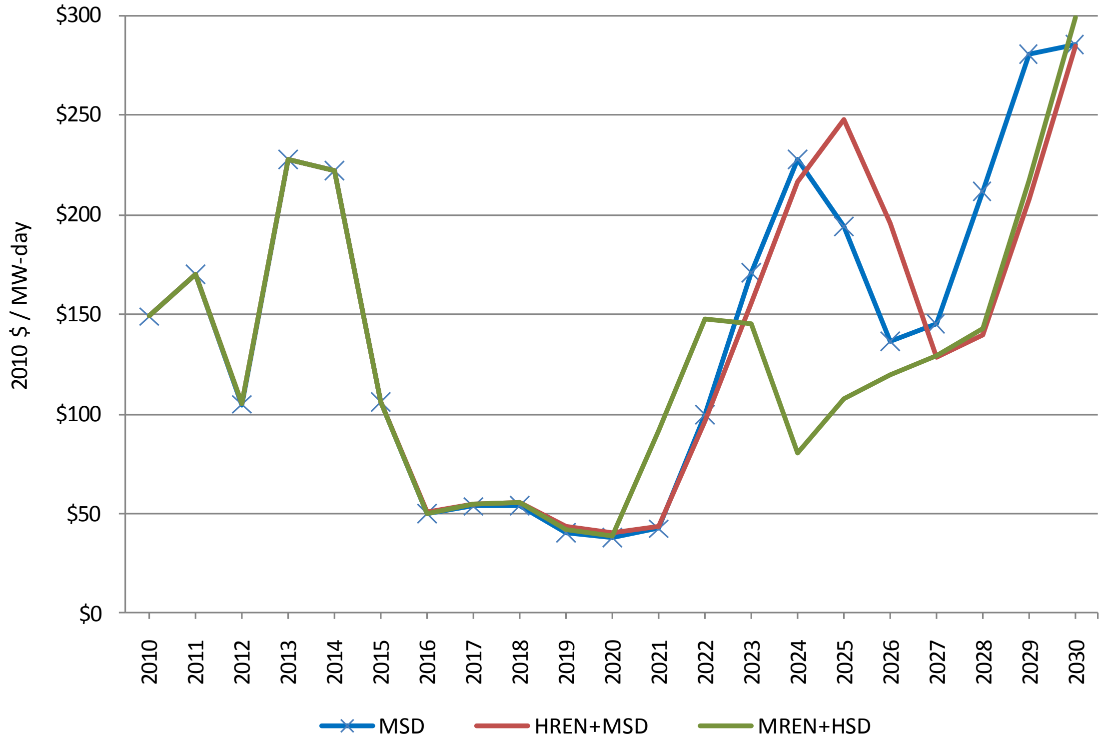
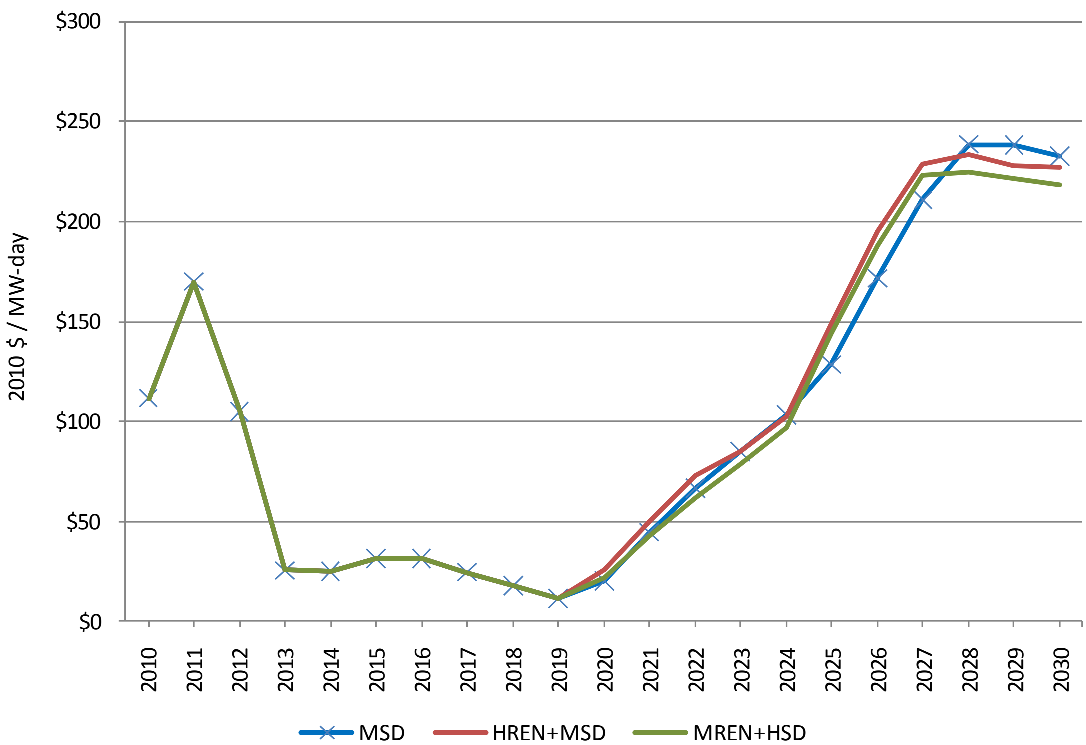


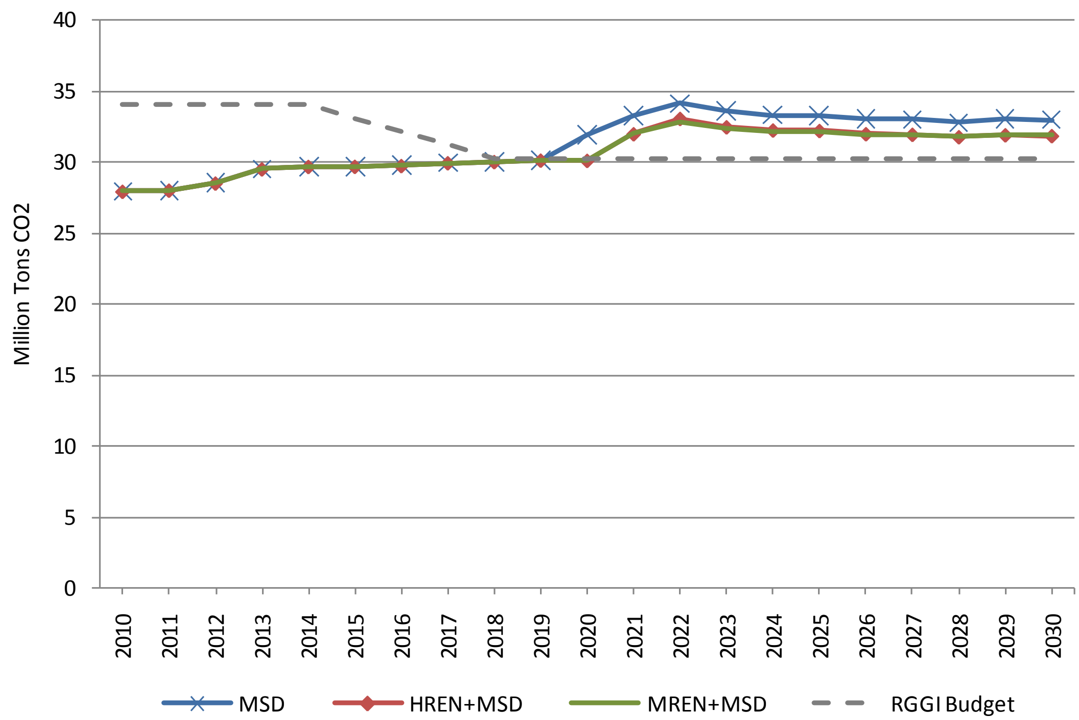
Figure 13.28 PJM-APS Capacity Prices – Medium Renewables Scenario



13.3.8 Emissions

Figure 13.29 shows the Maryland CO_2 emissions under the MSD, MREN+MSD, and HREN+MSD scenarios. Since coal consumption does not vary across the three scenarios after 2020 (see Figure 6.8), all differences in CO_2 emissions are driven by fewer natural gas units that are built in the MREN+MSD and HREN+MSD scenarios relative to the MSD scenario. The difference in the level of generation-based CO_2 emissions for the renewables scenarios is less than 10 percent compared to the MSD scenario.

Figure 13.29 Maryland Electric Generation CO_2 Emissions – Medium Renewables Scenario[52]



13.3.9 Results

The key results obtained from the Medium Renewables with MSD scenario are as follows:

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[52] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

- Adding additional renewable capacity does not have an appreciable impact on wholesale energy prices because renewable capacity is infra-marginal (i.e., an intermittent renewable energy resource is never the marginal unit dispatched) and, on average, higher levels of renewable generation do not displace a sufficient amount of conventional capacity at the margin to materially affect prices.
- The incremental renewable capacity displaces natural gas generation in Maryland rather than coal generation.
- Additional levels of renewable energy development do not materially affect capacity prices in either the PJM-SW or PJM-APS zones, though there are transitory impacts shown for PJM-MidE, with capacity prices generally lower than exhibited for the LTER Reference Case plus MSD scenario.

13.4 High Renewables, Aggressive Energy Efficiency, and Mt. Storm to Doubs Alternative Scenario

The High Renewables, Aggressive Energy Efficiency, and Mt. Storm to Doubs ("HREN+EE/MSD") alternative scenario combines the increased renewable capacity built in the HREN scenarios with the aggressive Maryland energy efficiency/conservation savings embodied in the EE scenarios described in chapter 10. In this section, the HREN+EE/MSD scenario is compared to the LTER Reference Case, HREN, and EE scenarios that also contained the Mt. Storm to Doubs transmission upgrade (MSD, HREN+MSD, and EE+MSD respectively).

13.4.1 Capacity Additions

The combination of aggressive energy efficiency/conservation and high renewables in Maryland along with the Mt. Storm to Doubs transmission upgrade reduces the need for new natural gas capacity in PJM as a whole by about 3.6 GW compared to the MSD scenario (see Table 13.5). In PJM-SW, the need for generic natural gas capacity is delayed by seven years, from 2020 in the MSD scenario, to 2027. Furthermore, only one combined cycle gas unit is built in PJM-SW in the HREN+EE/MSD scenario compared to three units built in the MSD scenario.

Table 13.5 Cumulative Natural Gas Capacity Additions Through 2030 – High Renewables and EE Scenarios (MW)

Scenario	PJM-SW	PJM-MidE	PJM-APS	PJM Total
MSD	1,431	3,816	4,770	30,145
HREN+MSD	9,54	3,210	4,293	28,933
EE+MSD	1,431	477	4,770	27,845
HREN+EE/MSD	477	954	4,770	26,588

The combination of aggressive energy efficiency and high renewables has a significant impact on new natural gas capacity additions in PJM-MidE. The first new combined cycle natural gas plant is built in 2027 under the EE+MSD scenario but under the HREN+EE/MSD scenario, the first unit comes online in 2022. Since PJM-SW delays new natural gas builds until 2027, PJM-MidE's ability to import energy from PJM-SW is reduced, which means that capacity is added five years earlier PJM-MidE region. In PJM-APS, generic gas builds in the HREN+EE/MSD are equal to the MSD and MSD+EE scenarios. Figure 13.30 through Figure 13.32 show the new natural gas capacity additions in each zone.

Figure 13.30 PJM-SW Natural Gas Capacity Additions – High Renewables and EE Scenario

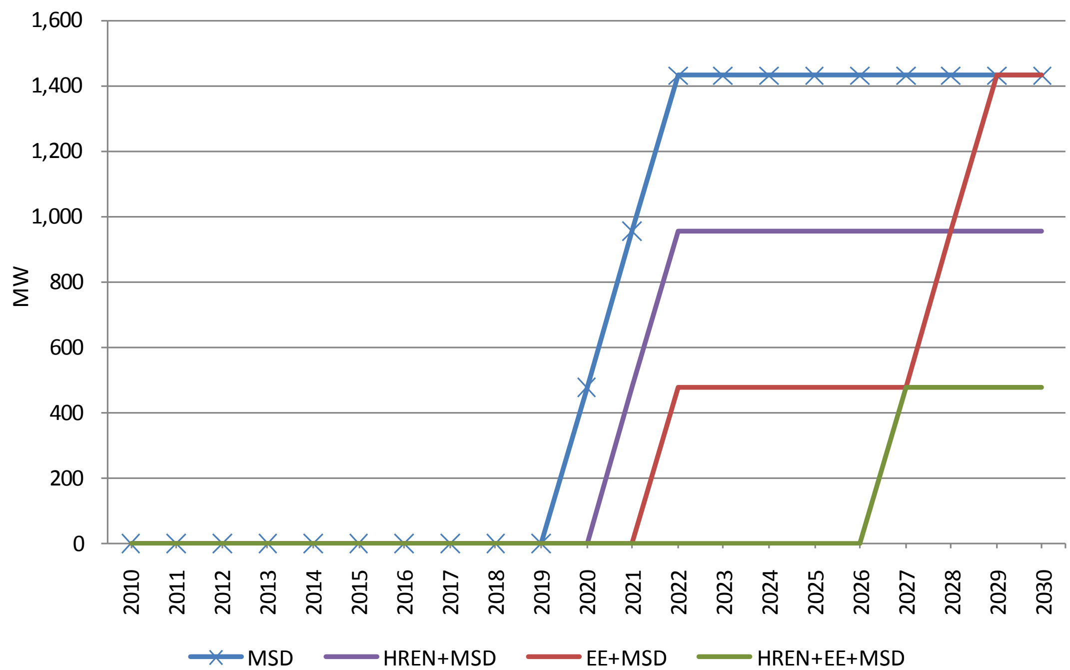


Figure 13.31 PJM-MidE Natural Gas Capacity Additions – High Renewables and EE Scenario

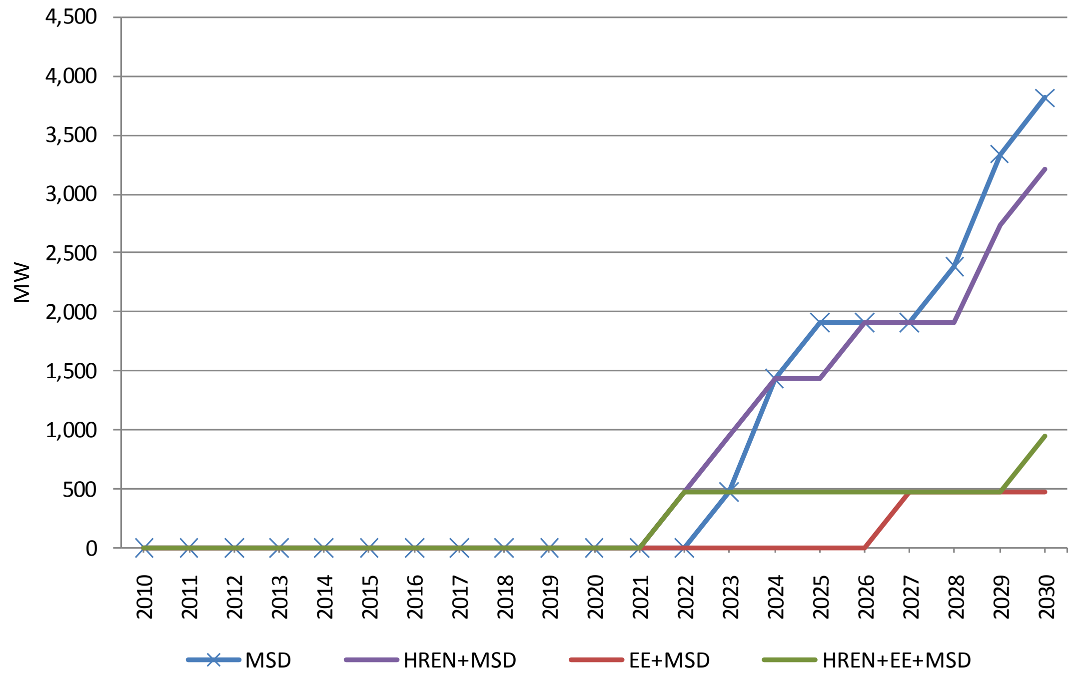
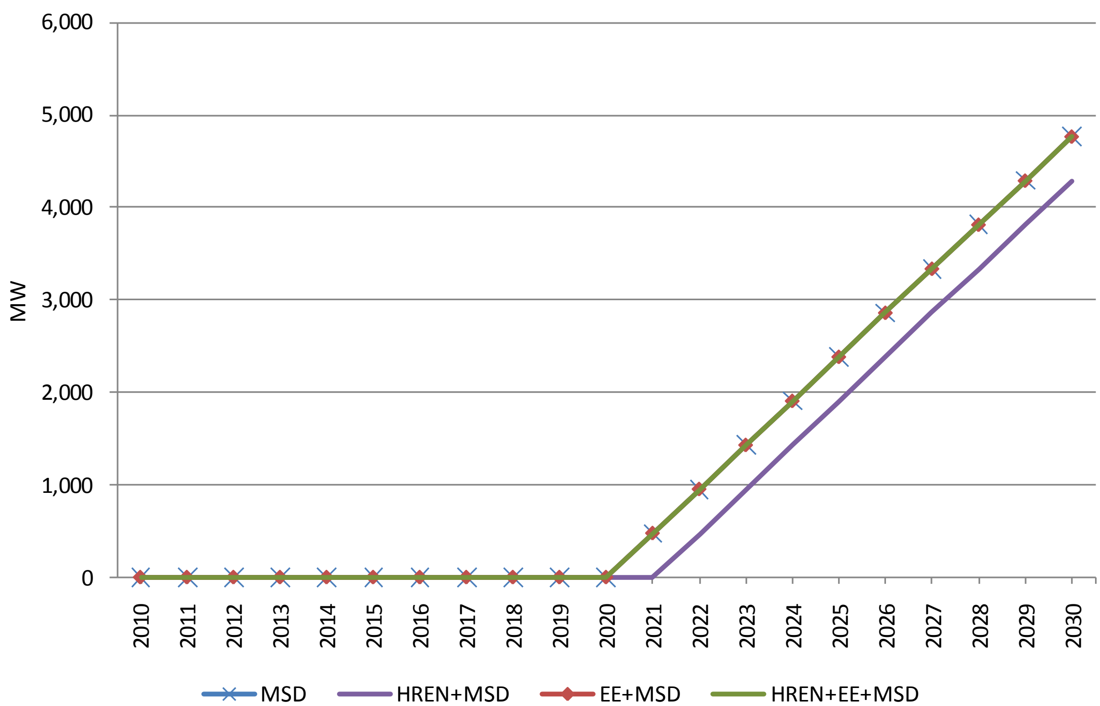


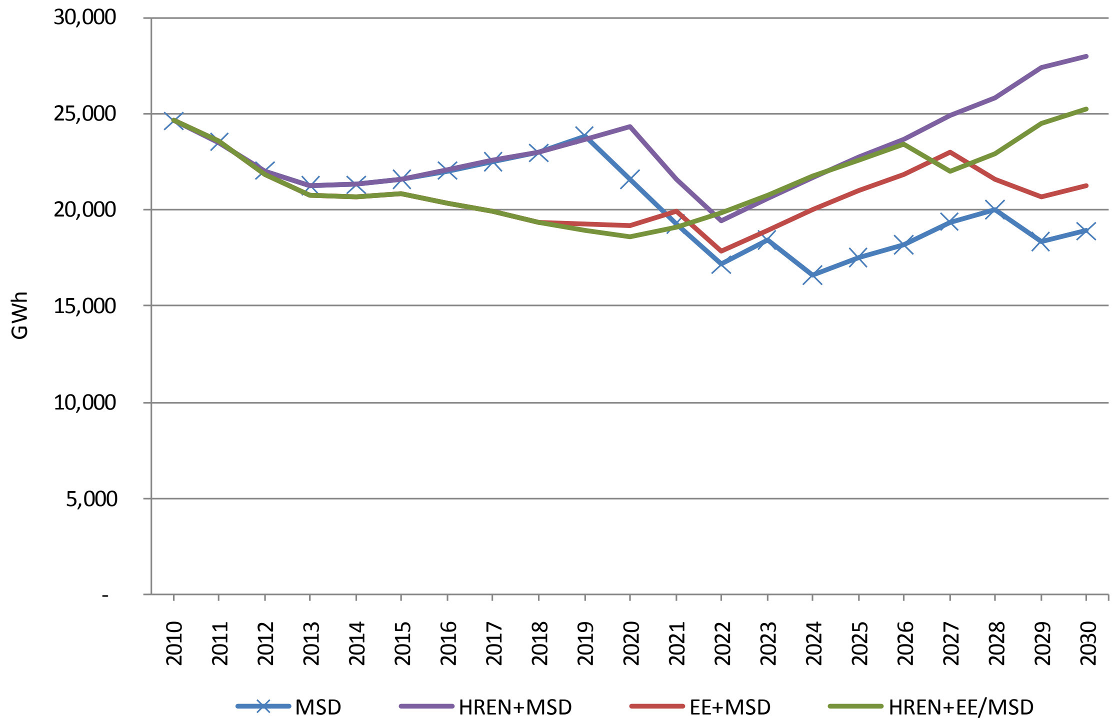
Figure 13.32 PJM-APS Natural Gas Capacity Additions – High Renewables and EE Scenario



13.4.2 Net Imports

PJM-SW's net imports under the HREN+EE/MSD largely lie between the HREN+MSD and EE+MSD cases (see Figure 13.33). PJM-SW's net imports are below the MSD scenario prior to 2021 but beyond that, net imports in the HREN+EE/MSD case are higher because less natural gas capacity is built in PJM-SW.

Figure 13.33 PJM-SW Net Imports – High Renewables and EE Scenario



PJM-MidE's net imports under the HREN+EE/MSD scenario also lie between the EE+MSD and HREN+MSD scenario, and net imports remain very close to the MSD case (see Figure 13.34). Under the EE assumptions, PJM-MidE does not build as much natural gas capacity as under the MSD and HREN+MSD scenarios and hence must import more energy, even though the MidE region has additional renewable capacity.

The PJM-APS region exports more energy under both the EE+MSD and HREN+MSD scenarios relative to the MSD scenario (see Figure 13.35) because fewer plants are built in the PJM-SW and PJM-MidE regions.

Figure 13.34 PJM-MidE Net Imports – High Renewables and EE Scenario

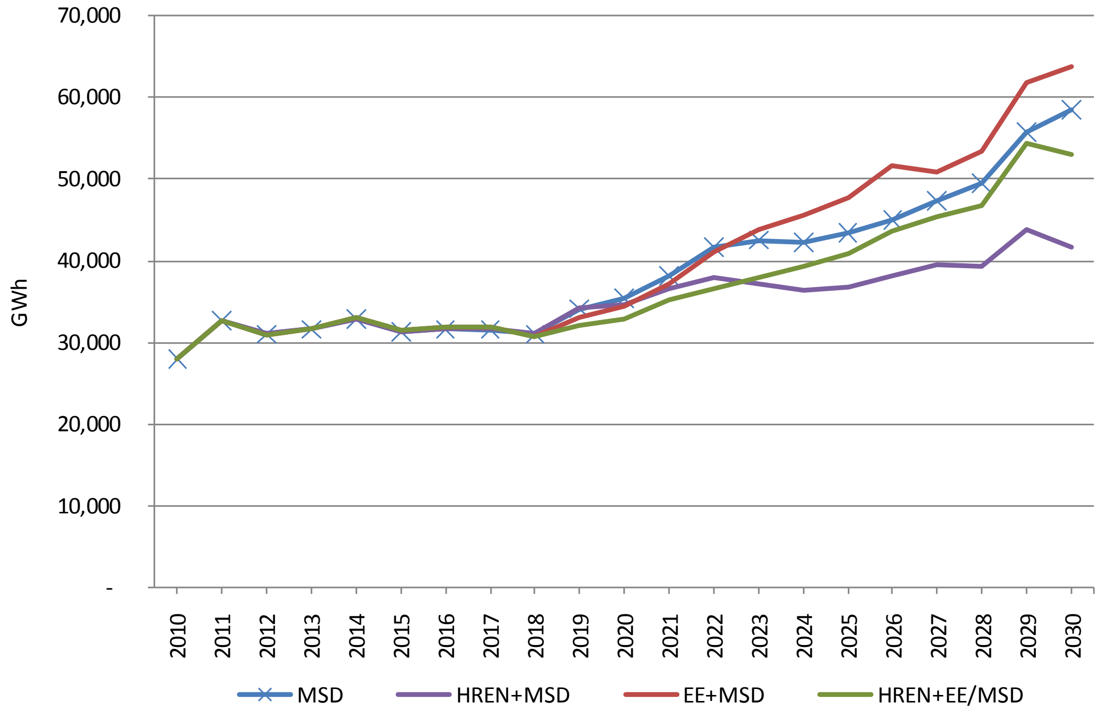
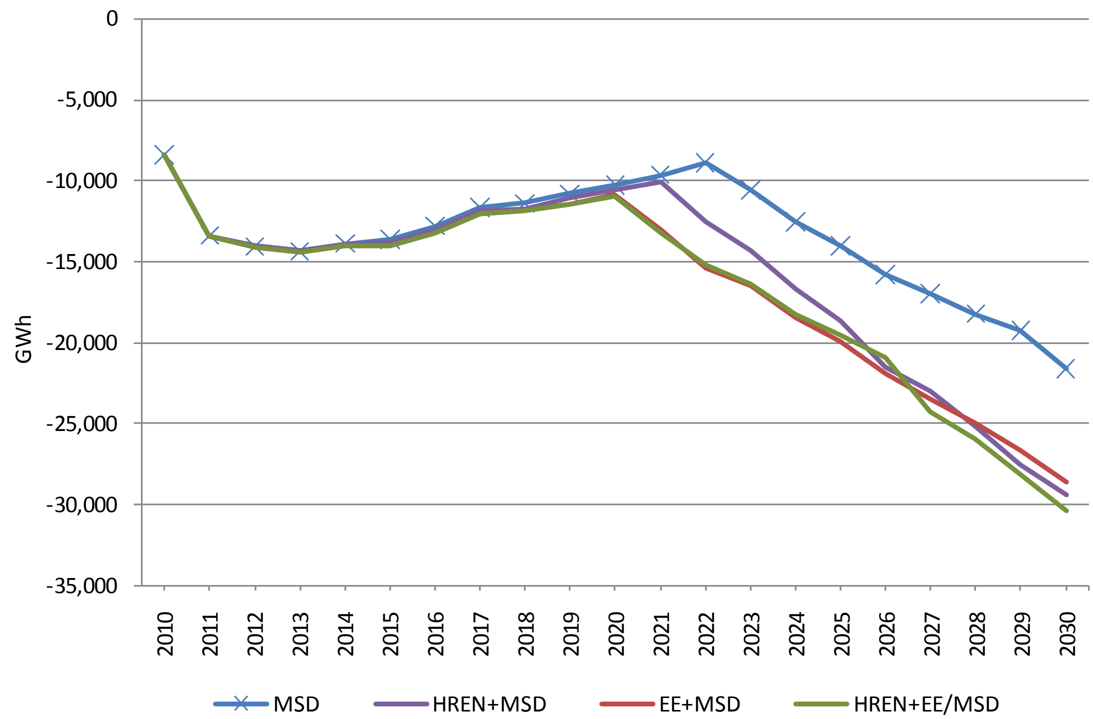


Figure 13.35 PJM-APS Net Imports – High Renewables and EE Scenario



13.4.3 Fuel Use

Coal consumption in Maryland is reduced with the introduction of both energy efficiency and renewable energy, which reduces the need for coal plants in Maryland to increase their capacity factors. Coal generation ramps up in 2020 in the MSD scenario and 2027 in the HREN+EE/MSD scenario (see Figure 13.36). Natural gas usage (Figure 13.37) in Maryland tracks the addition of natural gas capacity additions, which are lowest in the HREN+EE/MSD scenario.

Figure 13.36 Coal Use for Electricity Generation in Maryland – High Renewables and EE Scenario

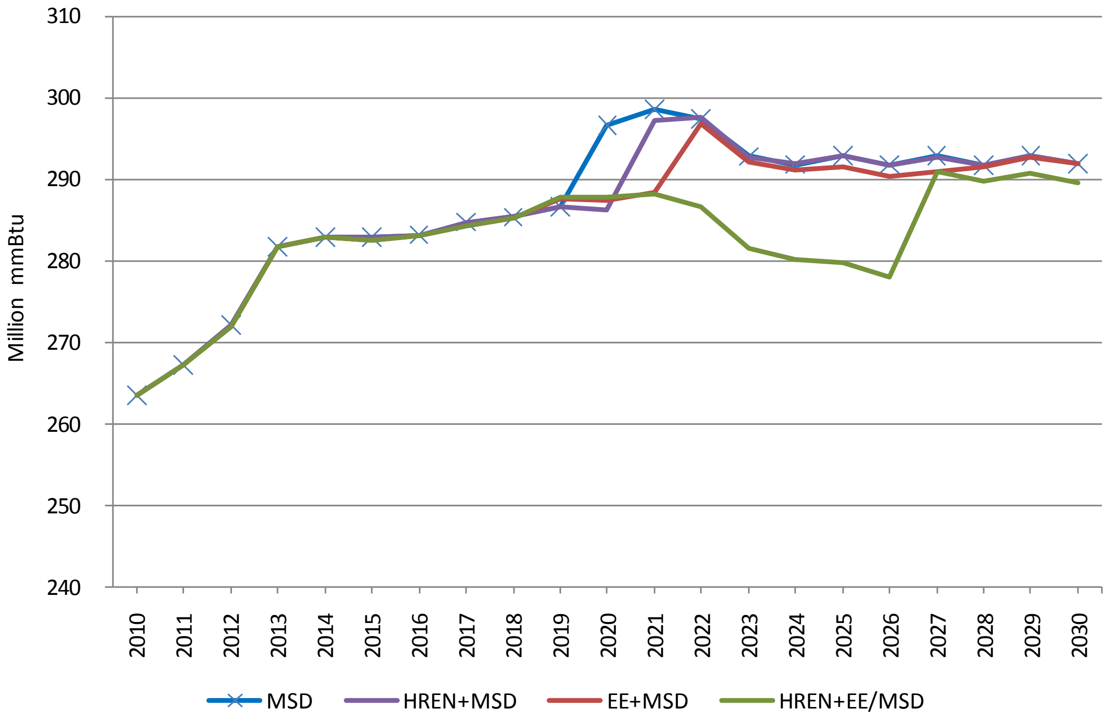
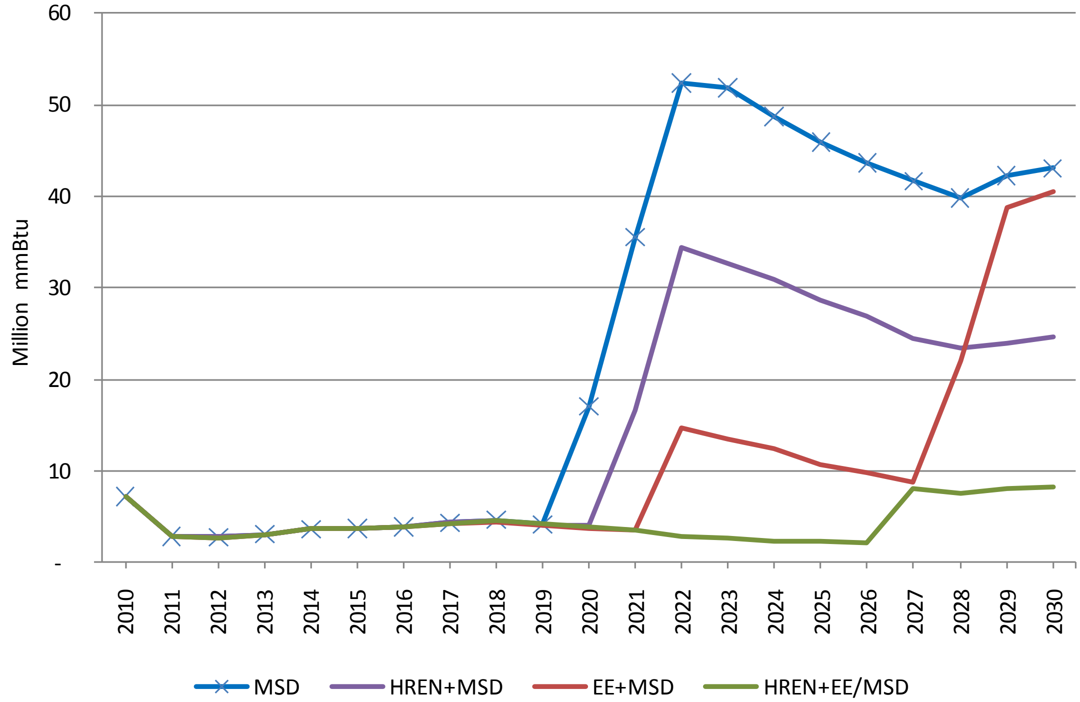


Figure 13.37 Natural Gas Use for Electricity Generation in Maryland – High Renewables and EE Scenario



The data presented in Figure 13.36 and Figure 13.37 indicate that the combination of increased renewable energy generation and aggressive energy efficiency/conservation programs results in both coal and natural gas generation being reduced. Where higher renewable generation was pursued in the absence of more aggressive energy efficiency and conservation programs, very little coal generation was displaced and most of the reduced conventional generation was from natural gas.

13.4.4 Energy Prices

Examining wholesale energy prices in isolation will give an incomplete picture of the HREN+EE/MSD scenario because these prices do not include the cost of achieving additional energy efficiency savings and constructing more renewable generating capacity. Furthermore, the energy efficiency cost curve is increasing, which means that the first 1,000 MWh of savings (e.g., more efficient lighting) will cost less than the last 1,000 MWh (e.g., geothermal heat pumps). The increased renewable capacity in the HREN scenarios also increases costs, and in the Ventyx model, these costs will be born through higher REC costs.[53] Figure 13.38 through Figure 13.40 show that neither higher renewable energy requirements nor more aggressive

[53] While REC prices would remain relatively stable, consumers would need to pay for more RECs to satisfy a higher RPS requirement.

energy efficiency and conservation by themselves, affect wholesale energy prices. The same holds true for the HREN+EE/MSD scenario, which is also similar to the MSD scenario.

Figure 13.38 PJM-SW Real All-Hours Energy Price – High Renewables and EE Scenario

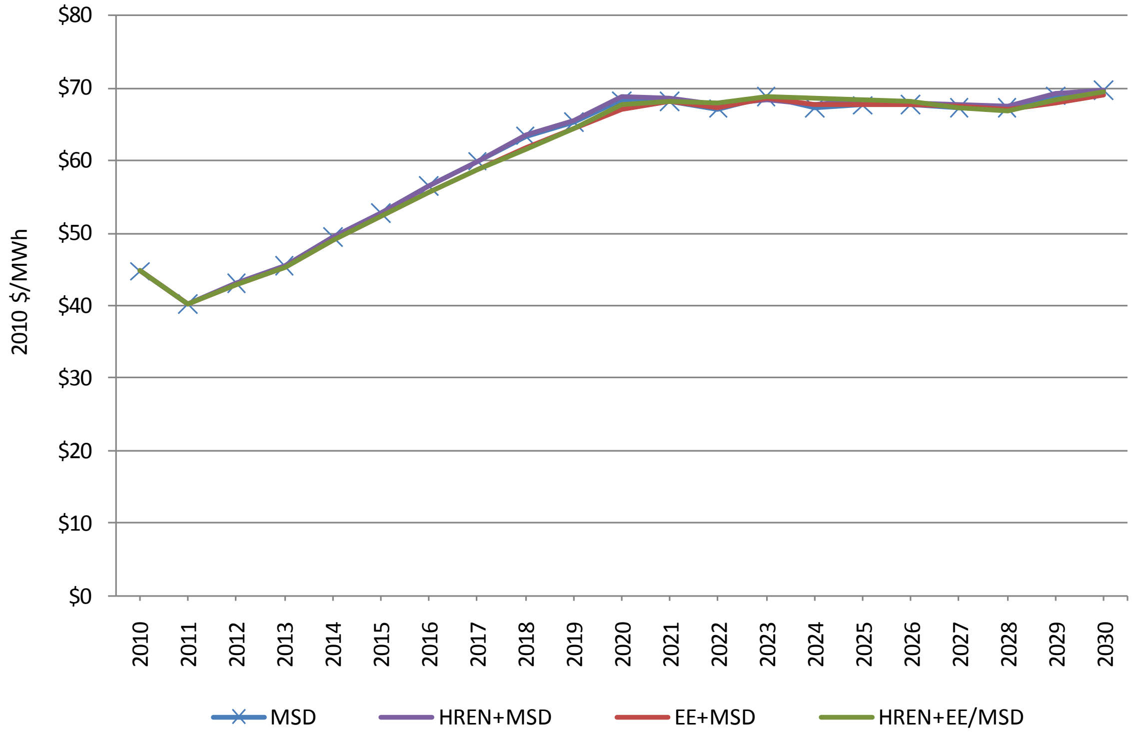


Figure 13.39 PJM-MidE Real All-Hours Energy Price – High Renewables and EE Scenario

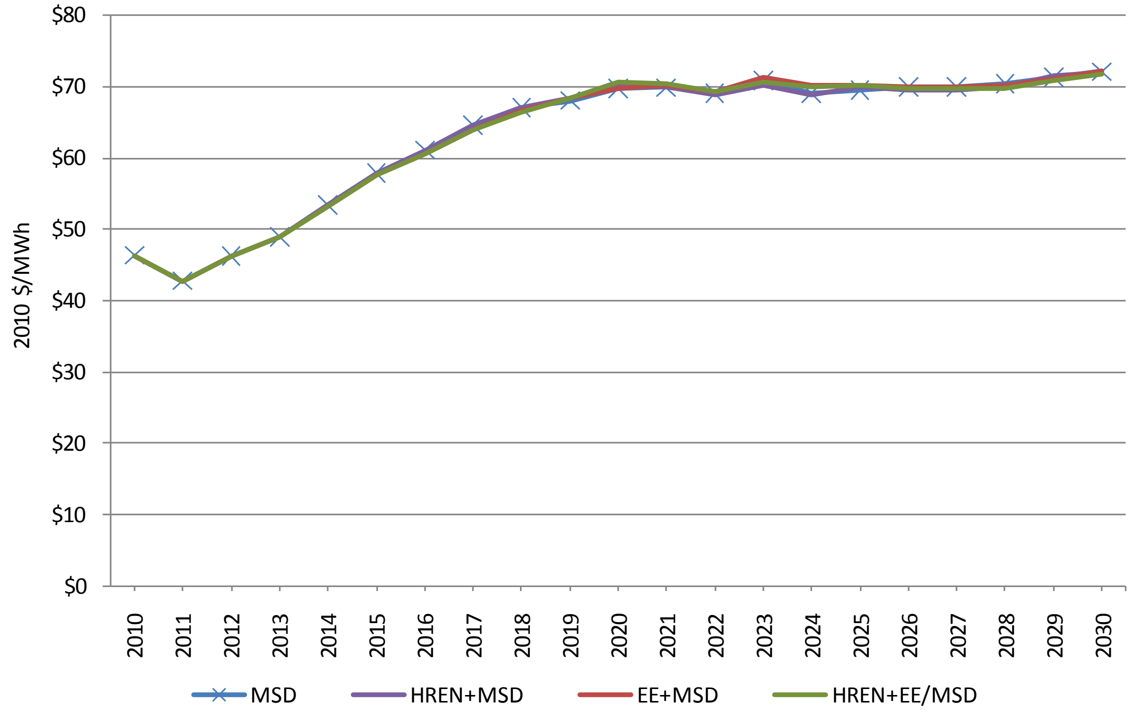
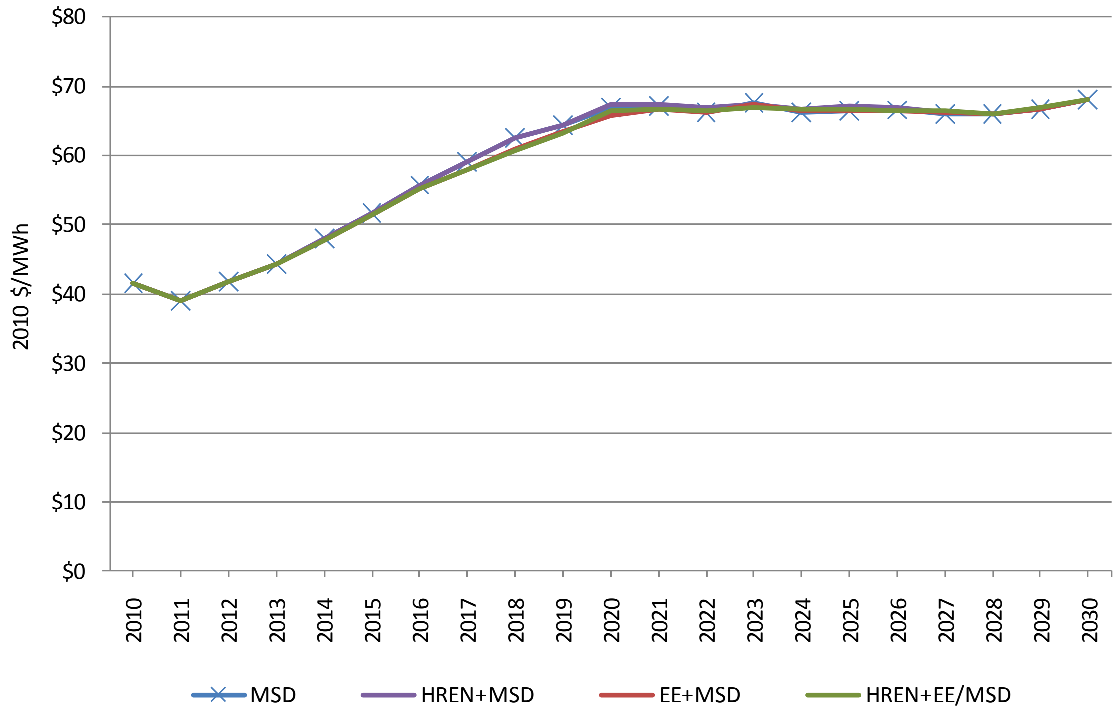


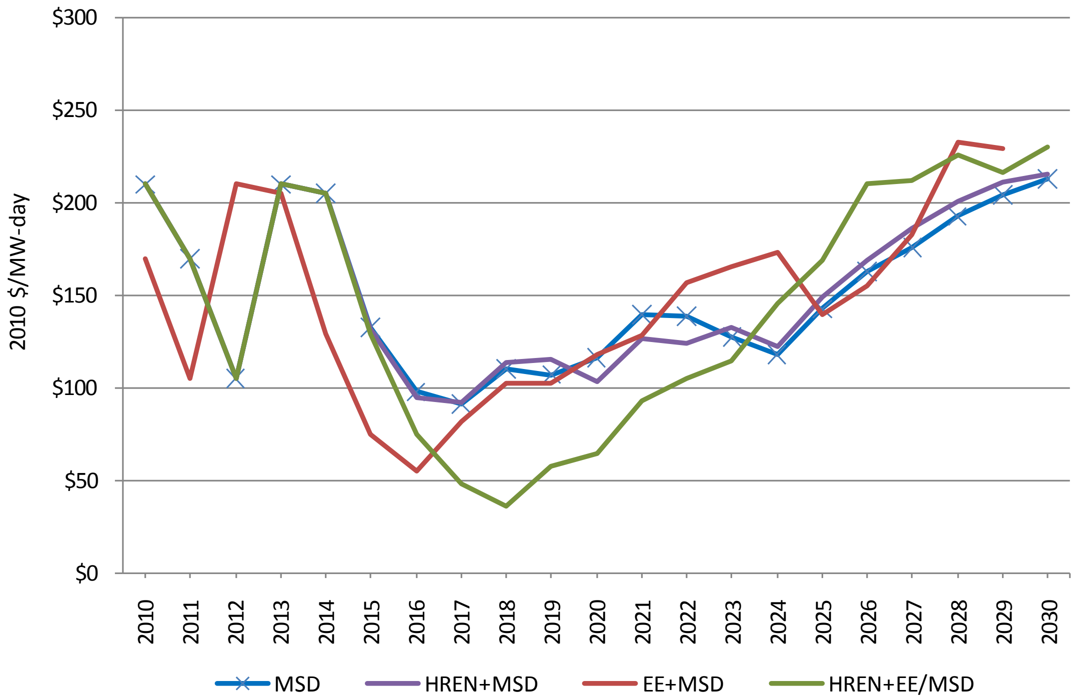
Figure 13.40 PJM-APS Real All-Hours Energy Price – High Renewables and EE Scenario



13.4.5 Capacity Prices

Figure 13.41 shows that the combination of high renewables and energy efficiency in Maryland decreases capacity prices in the early years but that capacity prices rise towards the end of the forecast period as growth consumes the existing excess capacity in PJM-SW. By 2030, the PJM-SW capacity prices across all scenarios are roughly equal.

Figure 13.41 PJM-SW Capacity Prices – High Renewables and EE Scenario



In PJM-MidE (see Figure 13.42), capacity prices for the HREN+EE/MSD scenario tend to be lower than the MSD and HREN+MSD scenarios. No consistent relationship exists between capacity prices in the HREN+EE/MSD and EE+MSD scenarios. These results suggest that capacity prices in the PJM-MidE zone are more responsive to reductions in load (e.g., resulting from aggressive energy efficiency/conservation programs) than to increased energy generation from renewable resources.

Capacity prices in PJM-APS (see Figure 13.43), are slightly lower for the HREN+EE/MSD scenario than for the other three scenarios but the differences are small and transitory.

Figure 13.42 PJM-MidE Capacity Prices – High Renewables and EE Scenario

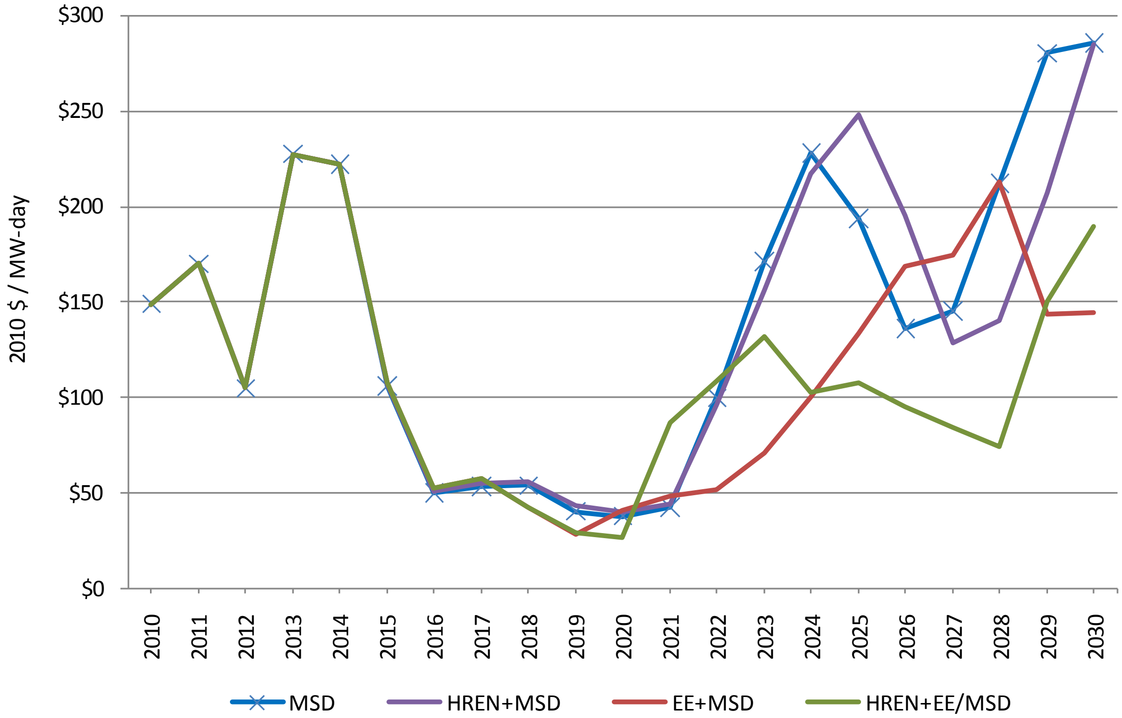
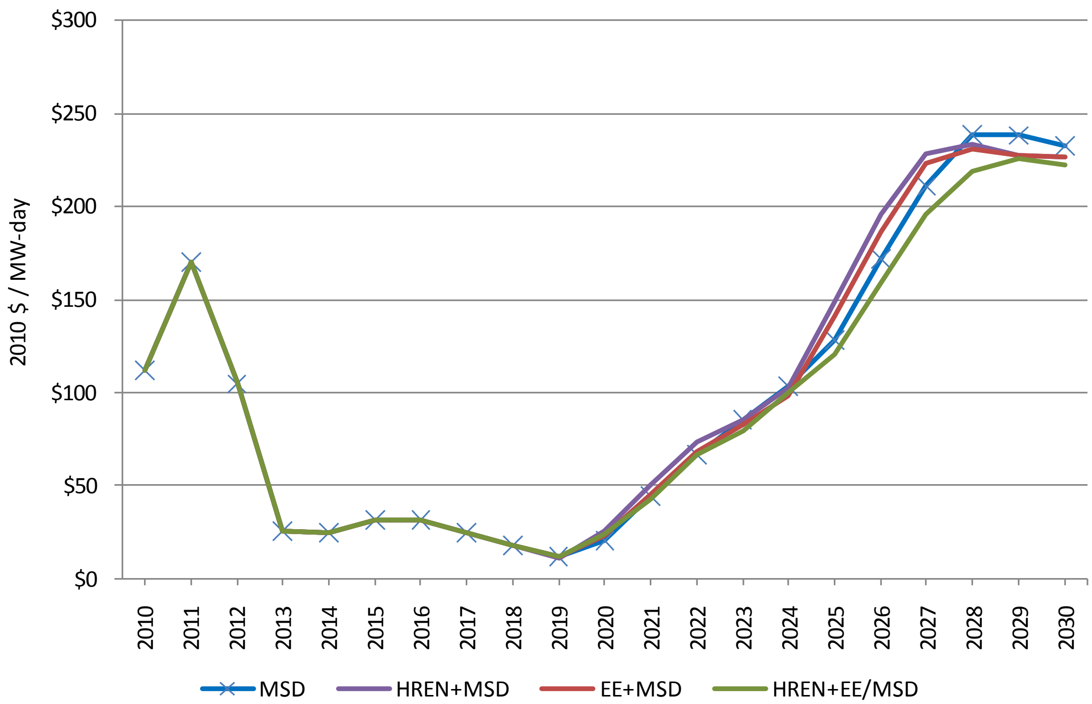


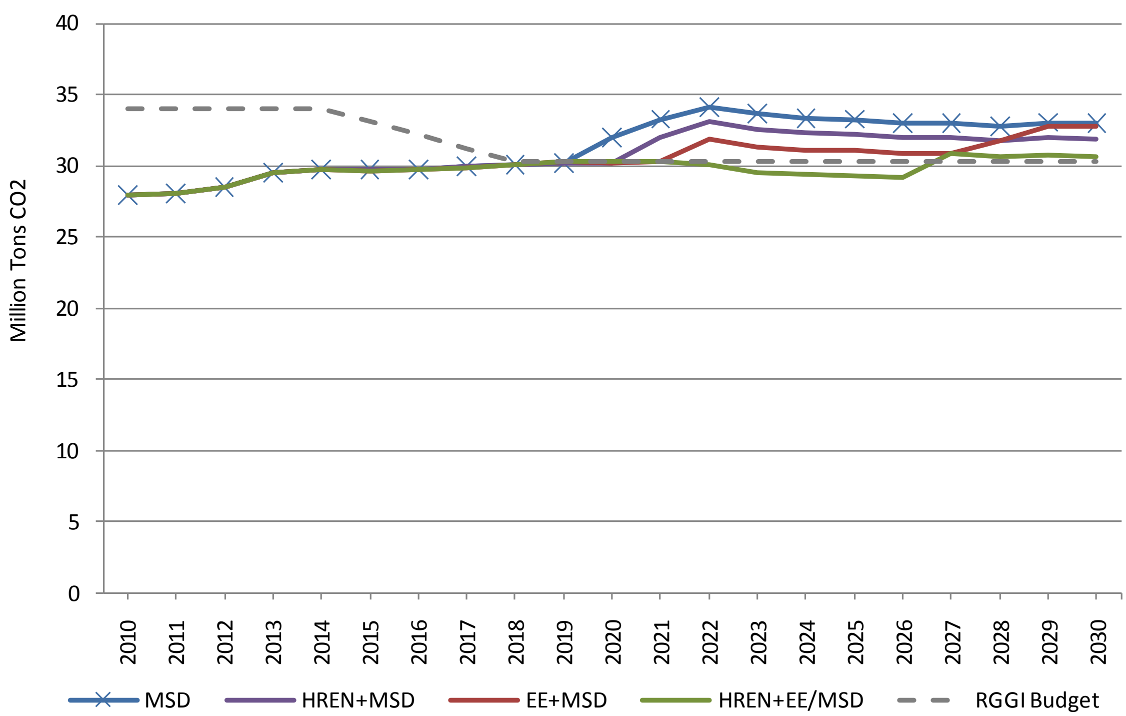
Figure 13.43 PJM-APS Capacity Prices – High Renewables and EE Scenario



13.4.6 Emissions

Carbon dioxide emissions from generation in Maryland are significantly reduced for the high renewables and energy efficiency scenarios relative the other scenarios considered (see Figure 13.44). As was shown in Figure 13.36, coal usage in the State is lower in the HREN+EE/MSD scenario compared to the MSD scenario, which results in lower CO_2 emissions in the HREN+EE/MSD scenario. Emissions under the HREN+EE/MSD scenario increase after 2027 when Maryland's coal plants begin to operate at higher capacity factors but CO_2 emissions remain below the MSD scenario emissions throughout the study period.

Figure 13.44 Maryland Electric Generation CO_2 Emissions – High Renewables and EE Scenario[54]



13.4.7 Results

The following key results based on the HREN+EE/MSD scenario are as follows:

- Emissions of CO_2 from generation in Maryland are lower under the HREN+EE/MSD scenario relative to the LTER Reference Case plus MSD scenario because coal plants in

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[54] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

Maryland do not operate at higher capacity factors until 2027 compared to 2020 in the LTER Reference Case plus MSD scenario.

- Approximately 3,500 MW of new natural gas generating capacity in PJM is avoided under the HREN+EE/MSD scenario relative to the LTER Reference Case plus MSD scenario. Approximately 1,000 MW are avoided in Maryland (PJM-SW) and 2,900 MW in the PJM-APS zone.
- The combination of more aggressive energy efficiency/conservation programs in Maryland and increased reliance on renewable generation sources results in reductions in both coal and natural gas generation in the State.

13.5 Coal Plant Life Extension Alternative Scenario

13.5.1 Introduction

The LTER Reference Case and all other scenarios assume that coal plants will retire after 65 to 75 years in service. Age-based retirements account for a substantial portion of the assumed retirements in PJM, but coal plants can delay retirement if continued operation is found to be profitable. The Coal Plant Life Extension with the Mt. Storm to Doubs transmission upgrade ("Life Xtsn+MSD") scenario extends the life of coal plants in PJM that met the following three conditions: (a) the capacity of the coal plant is at least 400 MW; (b) the plant has not announced plans to retire; and (c) the plant was scheduled to retire due to age in the Ventyx model. In aggregate, 4,223 MW of PJM coal generation capacity from six coal power plants had their lives extended in this scenario. Only 404 MW, or 9.6 percent, of the extended-life coal capacity is located in PJM-SW; the rest is located elsewhere in PJM (Table 13.6).[55]

Table 13.6 Coal Plant Life Extensions in Life Xtsn+MSD Scenario

Zone	MW
PJM-SW	404
PJM-MidE	0
PJM-APS	0
Rest of PJM	3,819
Total PJM	4,223

[55] The Coal Plant Life Extension + MSD scenario extended the operational lives of coal plants in the following zones: PJM-FE/ATSI - 577 MW; PJM-AEP - 2,804 MW; PJM-EPA - 438 MW; and PJM-SW - 404 MW (which can consist of multiple generation units).

Seventy percent of the coal capacity extended in the Life Xtsn+MSD scenario is assumed to retire in 2027 or later in the LTER Reference Case so the divergence between the two scenarios occurs primarily in the last four years of the study period. NO_x and SO_2 controls were also added to the 4,223 MW of coal capacity as part of the life-extension. In this section, the Life Xtsn+MSD scenario is compared to the LTER Reference Case scenario that contained the Mt. Storm to Doubs transmission upgrade (MSD).

13.5.2 Capacity Additions

Extending the operational lives of coal plants reduces the need for additional natural gas capacity by approximately ten percent and the new natural gas build schedules in the MSD and Life Xtsn+MSD scenarios do not diverge until 2024 when coal plant life extensions are first undertaken.

Table 13.7 Cumulative Natural Gas Capacity Additions Through 2030 – Life Extension Scenario (MW)

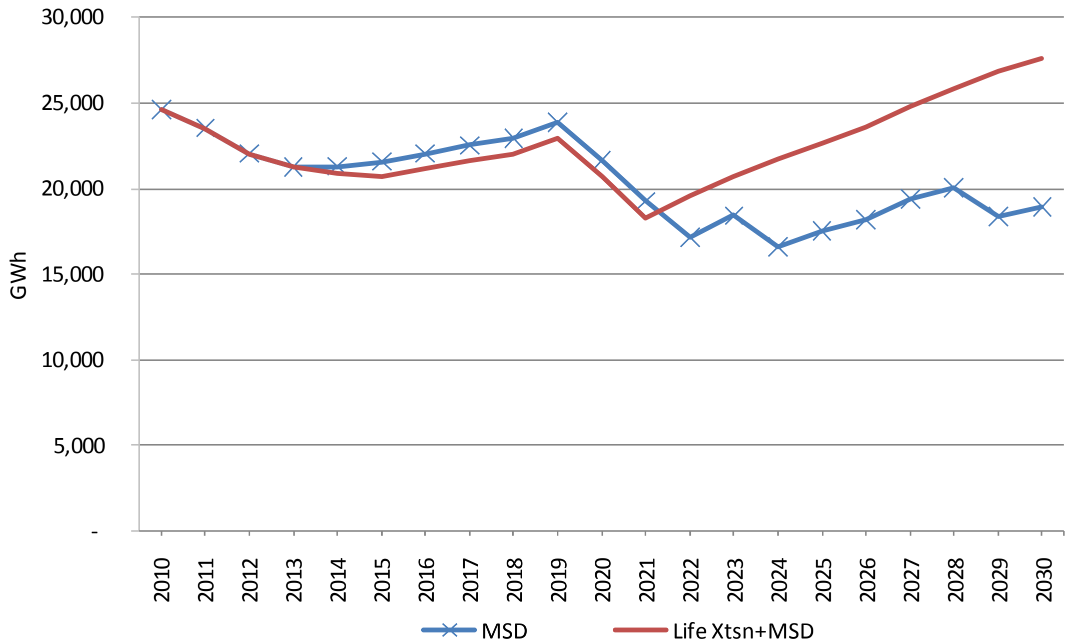
Scenario	PJM-SW	PJM-MidE	PJM-APS	PJM Total
MSD	1,431	3,816	4,770	30,145
Life Xtsn + MSD	954	954	4,293	27,239

PJM-SW requires only one additional combined cycle natural gas unit in the Life Xtsn+MSD scenario as opposed to two in the MSD scenario because of the 404 MW of coal capacity that stays online through 2030 in the Life Xtsn+MSD scenario. The coal plant life extensions eliminate the need for a significant amount of new natural gas capacity PJM-MidE, which instead imports energy from other regions. Finally, PJM-APS builds one fewer combined cycle unit given that the demand for imports is reduced in the Life Xtsn+MSD scenario.

13.5.3 Net Imports

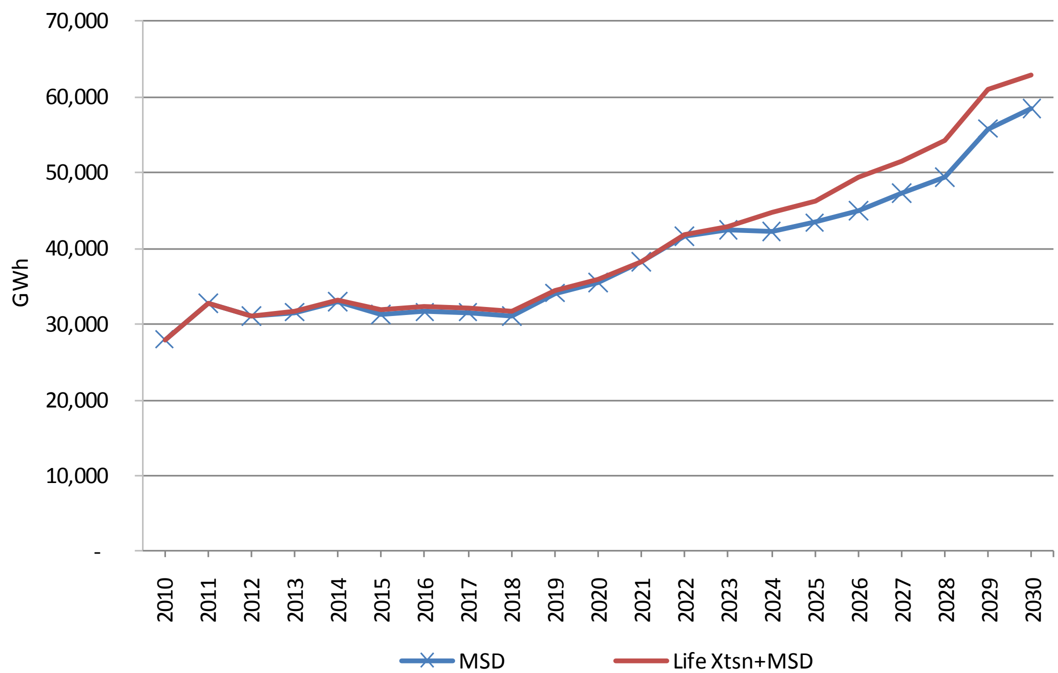
PJM-SW's net imports in the Life Xtsn+MSD scenario are initially slightly below the MSD scenario but in 2021 and beyond, the relationship changes. In the MSD scenario, the PJM-SW region builds a second combined cycle natural gas unit in 2021 but this unit does not get built in the Life Xtsn+MSD scenario. PJM-SW, therefore, must import more energy from neighboring regions.

Figure 13.45 PJM-SW Net Imports – Life Extension Scenario



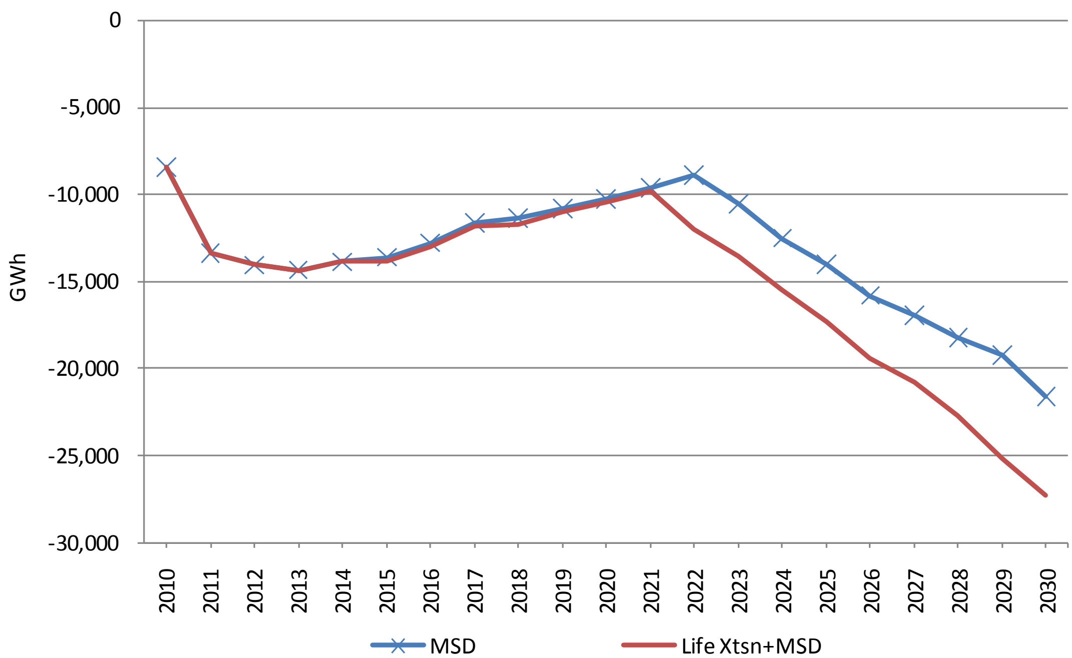
No plants have their operational lives extended in PJM-MidE but the zone builds fewer combined cycle natural gas units and therefore must import slightly more energy in the Life Xtsn+MSD scenario as compared to the MSD scenario (see Figure 13.46).

Figure 13.46 PJM-MidE Net Imports – Life Extension Scenario



The PJM-APS zone (Figure 13.47) exports less energy under the Life Xtsn+MSD scenario since extending the lives of coal plants reduces the demand for PJM-APS exports.

Figure 13.47 PJM-APS Net Imports – Life Extension Scenario



13.5.4 Fuel Use

Extending the operational life of 404 MW of coal capacity in PJM-SW does not affect coal usage in Maryland because the coal plant that was extended is not located in the State. However, the natural gas usage under the Life Xtsn+MSD scenario is approximately half the natural gas usage of the MSD scenario because the PJM-SW region only builds one combined cycle natural gas unit instead of two (see Table 13.8).

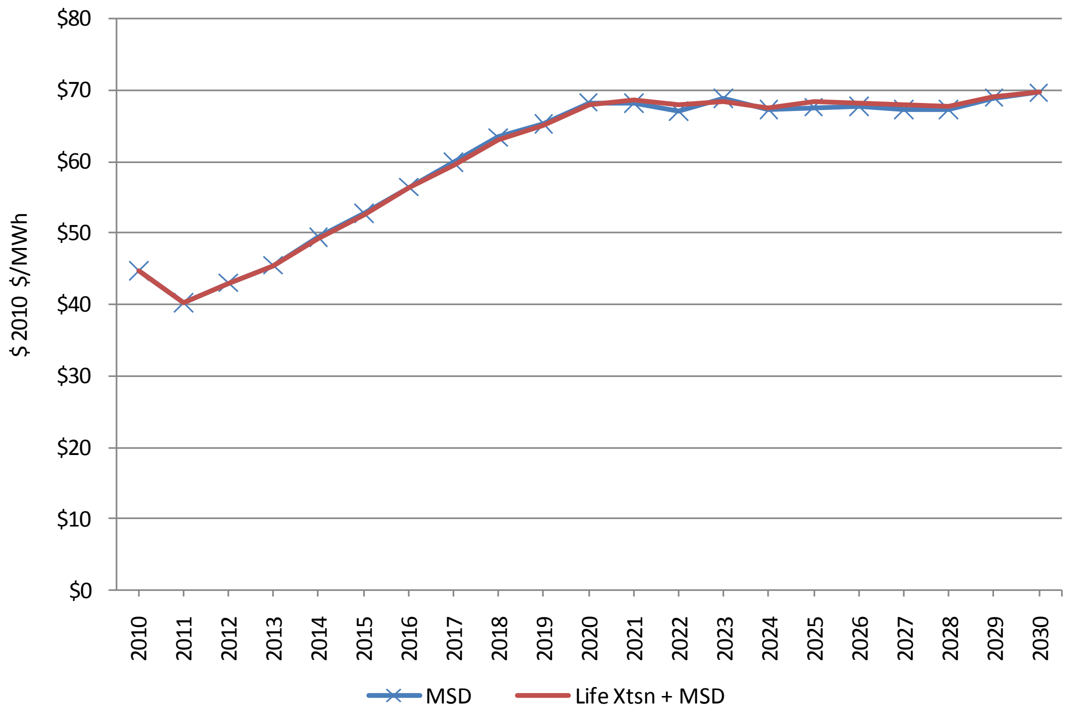
Table 13.8 Fuel Use for Electricity Generation in Maryland in 2030 - Life Extension Scenario

Scenario	Coal (mmBtu)	Natural Gas (mmBtu)
MSD	291,989,236	43,068,200
Life Xtsn+MSD	292,247,342	23,297,953

13.5.5 Energy Prices

The life extension scenario does not have a significant impact on wholesale energy prices in any of the three Maryland zones. Figure 13.48 shows energy prices for PJM-SW are virtually identical throughout the study period for both the MSD and the coal plant life extension scenario.

Figure 13.48 PJM-SW Real All-Hours Energy Price – Life Extension Scenario



Energy prices in PJM-MidE and PJM-APS under the Life Xtsn+MSD scenario are also unchanged when compared to the MSD scenario energy prices. The principal reason why energy prices do not deviate in the Life Xtsn+MSD scenario compared to the MSD scenario is that coal is an infra-marginal resource and hence does not set the wholesale price.

13.5.6 Capacity Prices

Capacity prices in PJM-SW under the Life Xtsn+MSD scenario closely track the capacity prices in MSD scenario throughout the period but are slightly lower in the 2015 to 2018 timeframe given the excess generating capacity that stays online. However, towards the end of the period, capacity prices under the Life Xtsn+MSD scenario are slightly higher than under the MSD scenario which results from the reduced investment in new natural gas capacity in the region.

Figure 13.49 PJM-SW Capacity Prices – Life Extension Scenario

In the PJM-MidE, capacity prices under the Life Xtsn+MSD scenario closely track the MSD scenario until 2023 and then diverge, with capacity prices for the Life Xtsn+MSD scenario being below those of the MSD scenario. The reason for the lower capacity prices in the Life Xtsn+MSD scenario is that coal plant life extension enables PJM-MidE to import less expensive energy from neighboring regions rather than build new capacity within the zone (see Figure 13.50). PJM-APS capacity prices are not affected by the plant life extensions because the region has ample internal reserves and no coal plants have their lives extended in PJM-APS.

Figure 13.50 PJM-MidE Capacity Prices – Life Extension Scenario

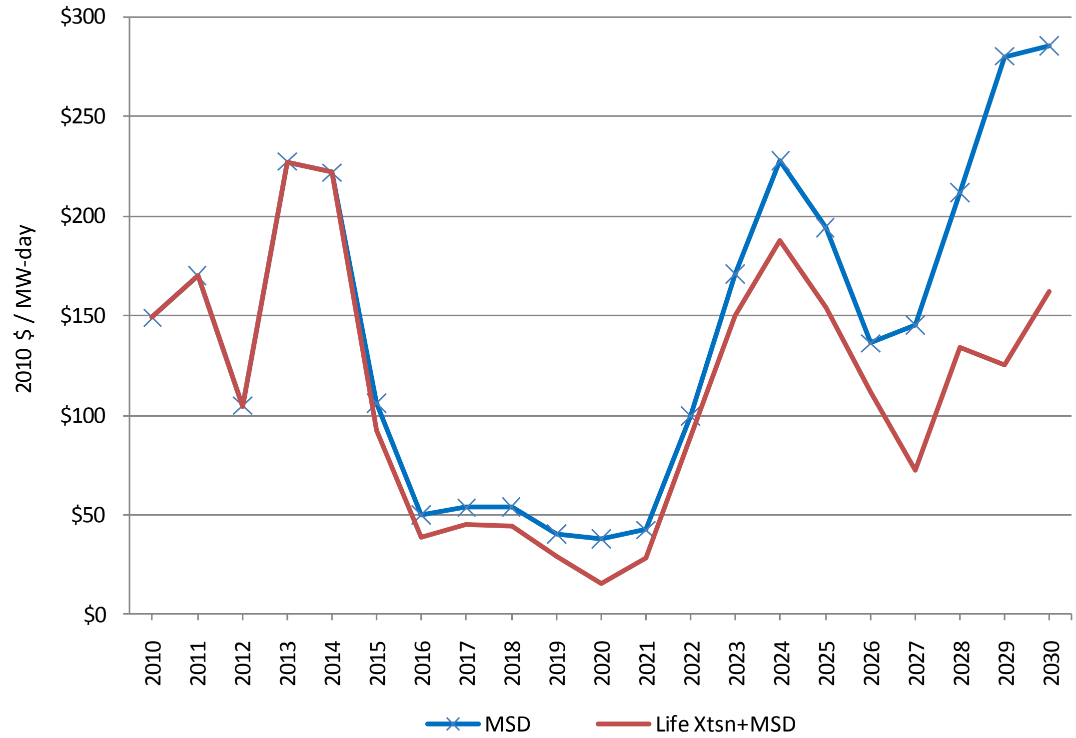
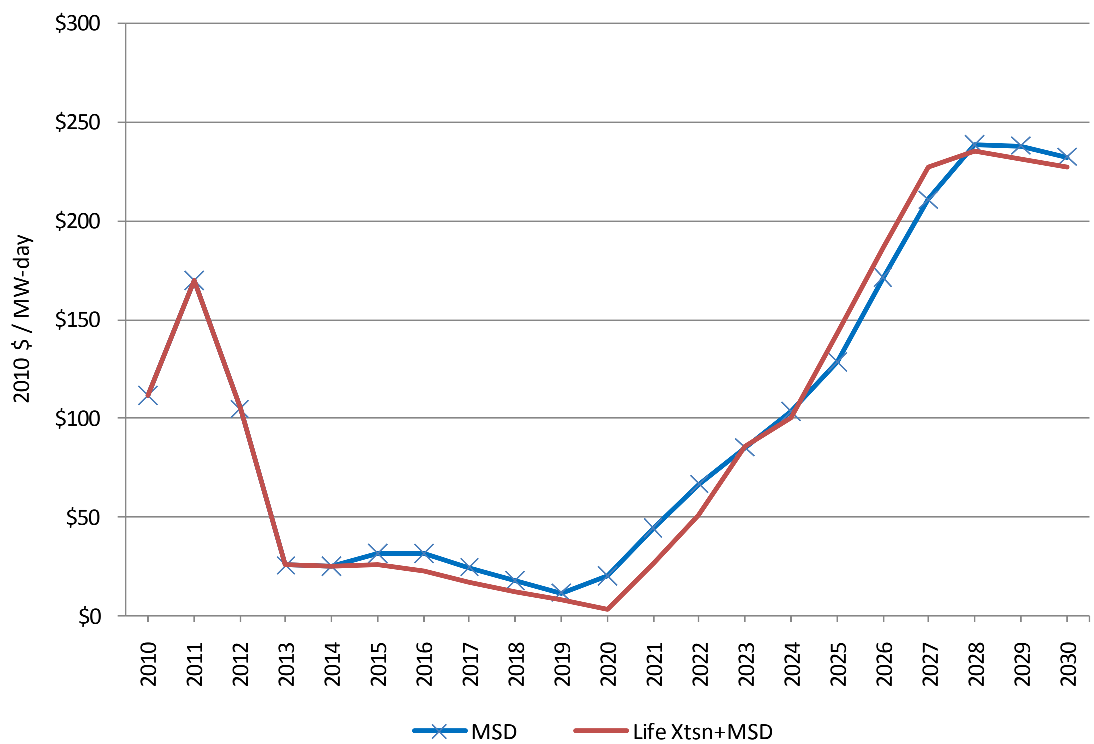


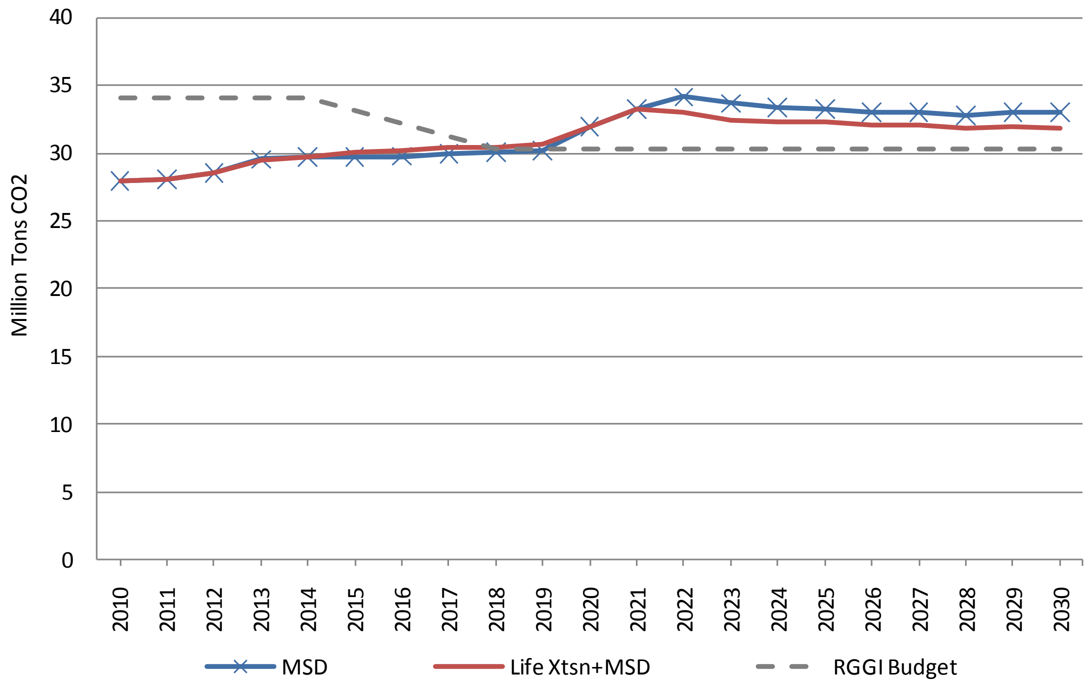
Figure 13.51 PJM-APS Capacity Prices – Life Extension Scenario



13.5.7 Emissions

Carbon dioxide emissions resulting from generation in Maryland are reduced slightly under the Life Xtsn+MSD scenario relative to the MSD scenario because the region only builds one combined cycle natural gas unit instead of two. Recall that coal plants in Maryland are not affected by the Life Xtsn+MSD scenario, that is, no plants n Maryland are subject to life extension under the Life Xtsn+MSD scenario. Maryland emissions decline slightly as a greater level of imports of low-cost coal generation are used to serve Maryland load.

Figure 13.52 Maryland Electric Generation CO_2 Emissions – Life Extension Scenario[56]



In PJM as a whole, CO_2 emissions are 2.55 percent higher under the Life Xtsn+MSD scenario as compared to the MSD scenario by the end of the period. Figure 13.53 shows that the MSD and Life Xtsn+MSD scenarios only diverge at the end of the study period because 70 percent of the extended coal plants were assumed to retire in the last four years of the study period. The SO_2 emissions in the Life Xtsn+MSD scenario are very close to the MSD scenario while NO_x emissions are 5.3 percent higher by 2030, with the divergence occurring after 2027.

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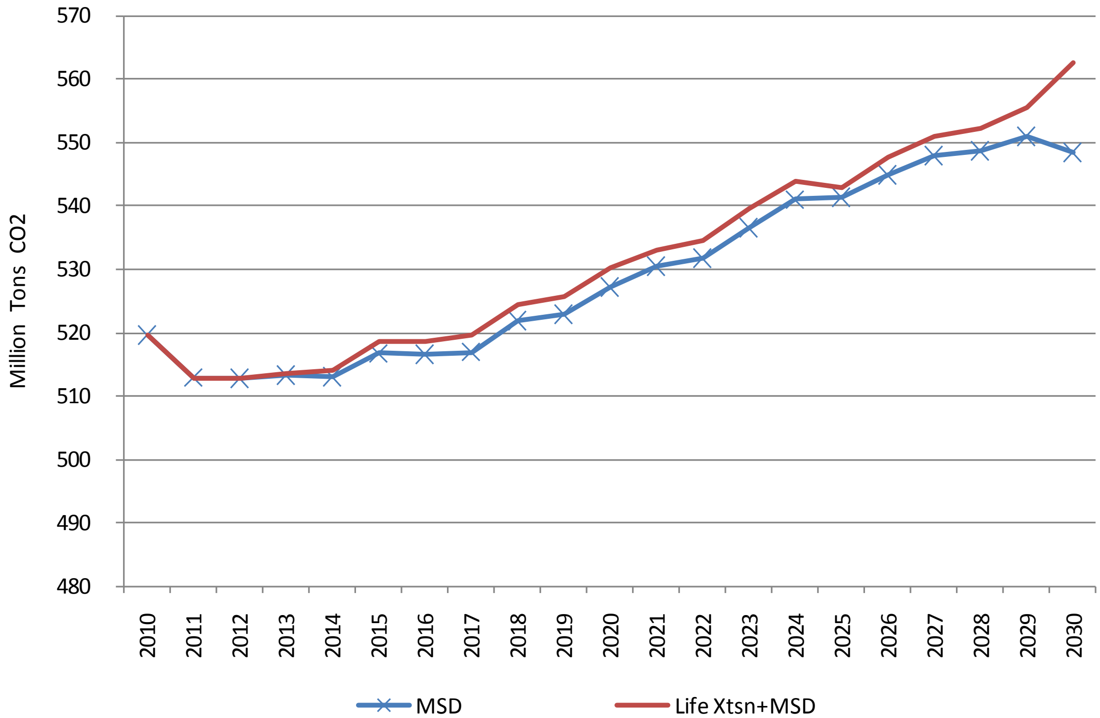
[56] PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this first LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

Figure 13.53 PJM Electric Generation CO_2 Emissions – Life Extension Scenario



13.5.8 Results

The key results of the Life Xtsn+MSD scenario are as follows:

- PJM CO_2 emissions are approximately 2.5 percent higher by the end of the study period relative to the LTER Reference Case plus MSD scenario if coal plants have their lives extended. The LTER Reference Case plus MSD and Life Xtsn+MSD scenario CO_2 emissions begin to diverge after 2026 when the majority of the life extensions occur.
- Maryland builds less new natural gas capacity if coal power plants have their lives extended.
- Energy and capacity prices in PJM-SW, PJM-MidE, and PJM-APS are not significantly affected by the coal plant life extensions.

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14. DISCUSSION TOPICS

14.1 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 include fuel diversity, reliability, emissions, price stability, total production costs and revenues, Renewable Energy Certificate ("REC") prices, net imports, and land use requirements.

14.2 Fuel Diversity

14.2.1 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.[57]

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-thirds (i.e., 1.333) so the

[57] 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.

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:

$$FDF = (1-(0.25^2 + 0.25^2 + 0.25^2 + 0.25^2)) \text{ x } 1.333 = 1.0$$

The minimum value of FDF (i.e., minimum diversity) is zero 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:

$$FDF = (1-(0^2 + 1^2 + 0^2 + 0^2)) \text{ x } 1.333 = 0.0$$

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:

$$FDF = (1-(0.15^2 + 0.60^2 + 0.20^2 + 0.05^2)) \text{ x } 1.333 = 0.77$$

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.

14.2.2 Diversity in Maryland Generation

Table 14.1, Table 14.2, and Table 14.3 show the calculated FDFs for Maryland generation for each of the scenarios considered, including the LTER Reference Case.[58] 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 two scenarios that include EPA's proposed new regulations also exhibit relatively high diversity factors due to the retirement of more coal-fired capacity. 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. The High Renewables plus Energy Efficiency scenario also exhibits a relatively low diversity factor due to natural gas generation being inhibited by renewables development and comparatively low rates of growth due to aggressive energy efficiency and conservation programs being pursued in Maryland.

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; 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, and the scenarios depicting low load growth in combination with aggressive energy efficiency and conservation programs throughout PJM.

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[58] The analogous information for the Supplemental Responsive Scenarios is presented in Appendix L, Table L-9.

Table 14.1 Fuel Diversity – Maryland 2010*

Scenario	Nuclear (%)	Coal (%)	Gas (%)	Renewable (%)	Diversity Factor**
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
EPA Reg + MSD	31.8	59.9	1.6	6.7	0.71
EPA Reg + MSD/MAPP	31.8	59.9	1.6	6.7	0.71
Low Load + PJM EE	31.8	59.9	1.6	6.7	0.71
Med Renew + MSD	31.8	59.9	1.6	6.7	0.71
High Renew + EE/MSD	31.8	59.9	1.6	6.7	0.71
Life Xtsn + MSD	31.8	59.9	1.6	6.7	0.71

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.
**Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)
$(1-((\text{nuclear share})^2+(\text{coal share})^2+(\text{gas share})^2+(\text{renewables share})^2))\text{x}(4/3)$

Table 14.2 Fuel Diversity – Maryland 2020*

Scenario	Nuclear (%)	Coal (%)	Gas (%)	Renewable (%)	Diversity Factor**
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
EPA Reg + MSD	27.0	56.0	7.7	8.3	0.80
EPA Reg + MSD/MAPP	26.7	55.5	8.6	9.2	0.81
Low Load + PJM EE	29.7	60.0	0.4	9.9	0.72
Med Renew + MSD	27.7	57.0	0.7	14.6	0.77
High Renew + EE/MSD	28.7	59.4	0.8	11.1	0.74
Life Xtsn + MSD	27.6	58.6	4.3	9.5	0.76

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.
**Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

Table 14.3 Fuel Diversity – Maryland 2030*

Scenario	Nuclear (%)	Coal (%)	Gas (%)	Renewable (%)	Diversity Factor**
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
EPA Reg + MSD	24.8	50.7	15.9	8.6	0.87
EPA Reg + MSD/MAPP	22.2	45.3	24.7	7.8	0.90
Low Load + PJM EE	27.9	58.1	4.6	9.4	0.76
Med Renew + MSD	23.8	49.7	5.9	20.6	0.87
High Renew + EE/MSD	22.8	47.3	1.8	28.1	0.86
Life Xtsn + MSD	26.0	54.3	10.6	9.1	0.82

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.
**Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

14.2.3 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 14.4, Table 14.5, and Table 14.6 in the same manner as the analogous data were presented in the previous tables.[59]

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 0.91. The scenario with the highest FDF is the Combined Events scenario (a Supplemental Responsive Scenario described in Appendix L) that includes higher load growth, low natural gas prices, and higher levels of coal plant retirements.

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, include national carbon legislation, or include high levels of coal plant retirements.

[59] The analogous projections for the Supplemental Responsive Scenarios are provided in Appendix L, Table L-10.

Table 14.4 Fuel Diversity – PJM 2010*

Scenario	Nuclear (%)	Coal (%)	Gas (%)	Renewable (%)	Diversity Factor**
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
EPA Reg + MSD	31.1	57.8	8.0	3.1	0.75
EPA Reg + MSD/MAPP	31.1	57.8	8.0	3.1	0.75
Low Load + PJM EE	31.1	57.8	8.0	3.1	0.75
Med Renew + MSD	31.1	57.8	8.0	3.1	0.75
High Renew + EE/MSD	31.1	57.8	8.0	3.1	0.75
Life Xtsn + MSD	31.1	57.8	8.0	3.1	0.75

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.
**Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

Table 14.5 Fuel Diversity – PJM 2020*

Scenario	Nuclear (%)	Coal (%)	Gas (%)	Renewable (%)	Diversity Factor**
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
EPA Reg + MSD	29.0	53.5	10.0	7.5	0.82
EPA Reg + MSD/MAPP	28.9	53.4	10.2	7.5	0.82
Low Load + PJM EE	31.2	54.1	7.1	7.6	0.80
Med Renew + MSD	29.3	53.6	9.3	7.8	0.82
High Renew + EE/MSD	29.5	53.8	9.1	7.6	0.81
Life Xtsn + MSD	29.2	54.0	9.3	7.5	0.81

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.
**Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

Table 14.6 Fuel Diversity – PJM 2030*

Scenario	Nuclear (%)	Coal (%)	Gas (%)	Renewable (%)	Diversity Factor**
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
EPA Reg + MSD	25.2	46.4	19.5	8.9	0.90
EPA Reg + MSD/MAPP	25.2	46.2	19.7	8.9	0.90
Low Load + PJM EE	29.2	51.3	10.1	9.4	0.84
Med Renew + MSD	25.2	46.8	18.4	9.6	0.90
High Renew + EE/MSD	25.4	47.2	17.2	10.2	0.90
Life Xtsn + MSD	25.1	48.6	17.5	8.8	0.88

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.
**Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

14.3 Reliability

Adequate electric infrastructure is required to provide reliable power supplies at reasonable prices. 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 the 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. This 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 those 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 potential long-term 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 area's) 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.

14.4 Emissions from Electricity Consumption in Maryland

14.4.1 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 13 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 (including transmission and distribution system losses) in Maryland under each scenario to estimate Maryland's pro-rata share of PJM emissions.[60]

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.[61] 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

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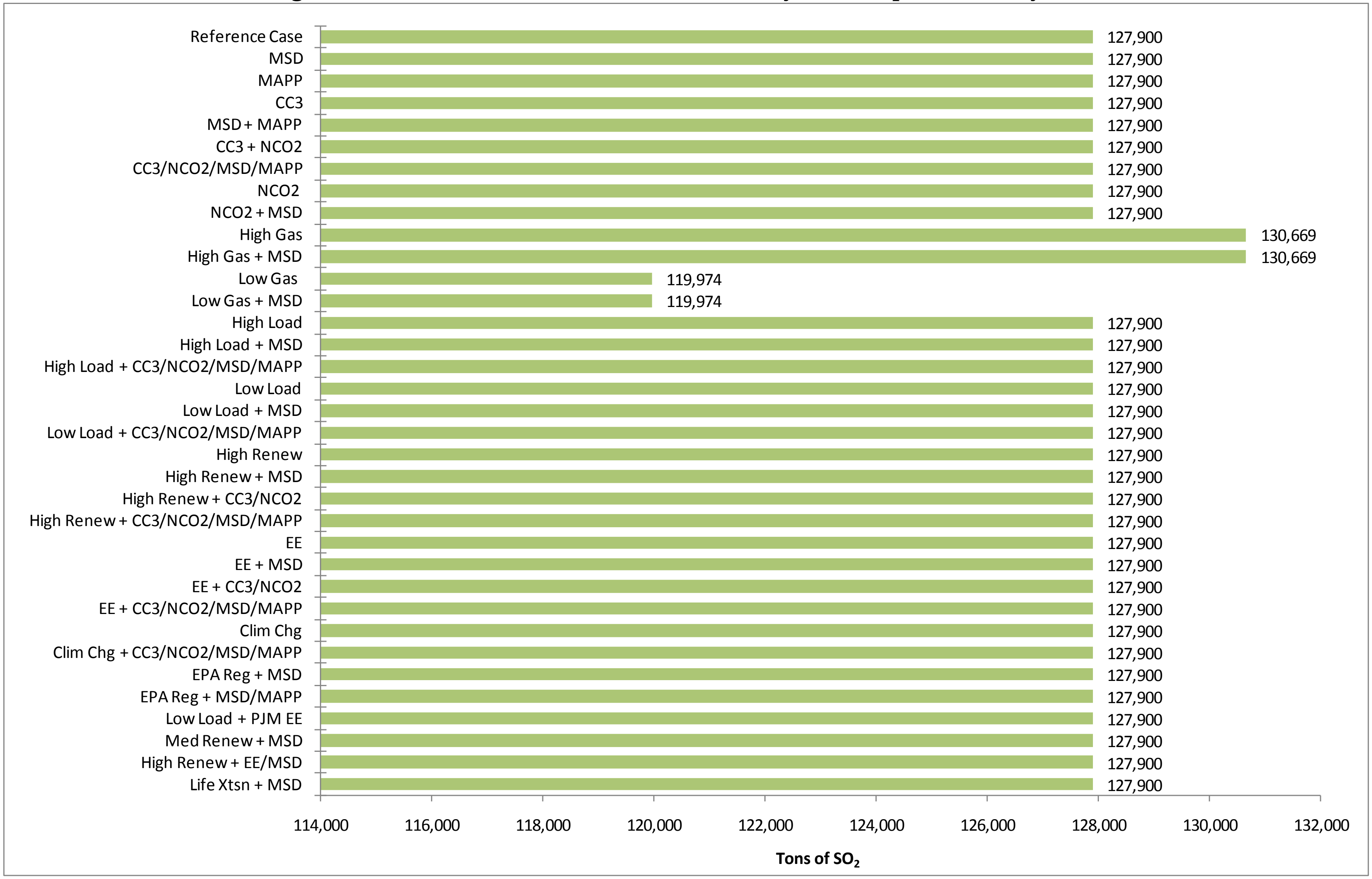
[60] The LTER adopted a value of 7 percent for T&D losses per the Energy Information Administration's national average estimate.
[61] Maryland's required level of renewable energy consumption was increased for the High and Medium Renewables scenarios.

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.

14.4.2 Emissions Graphs

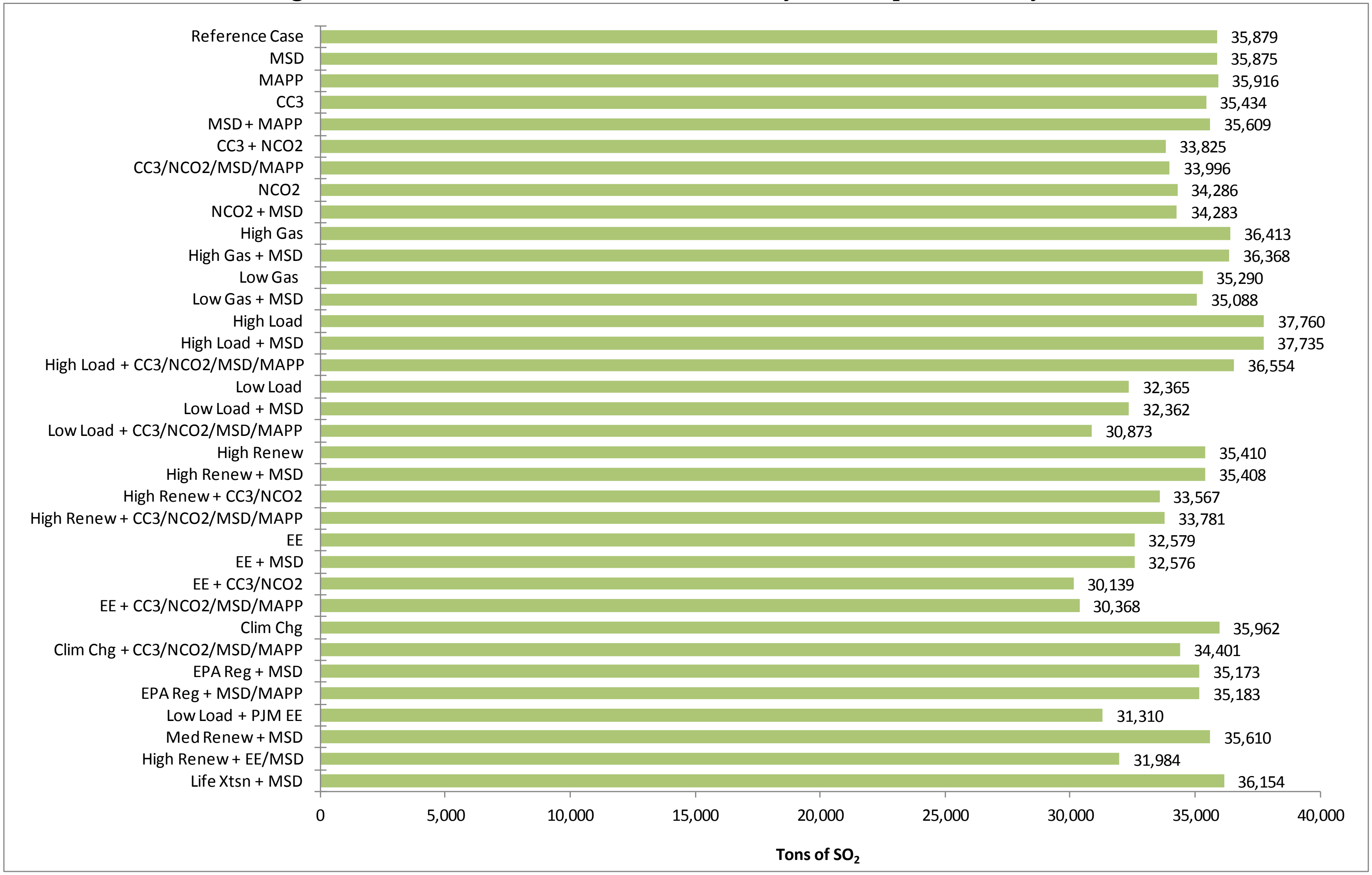
Based on these calculations, Figure 14.1 through Figure 14.24 illustrate the level of emissions associated with energy consumption in Maryland for each scenario considered in the main body of the LTER. There are three graphs for each pollutant which display the level of emissions in 2010, 2020, and 2030. Additionally, there are three more graphs for each pollutant that show annual averages for the periods 2010 through 2030, 2010 through 2020, and 2021 through 2030.

Figure 14.1 2010 SO_2 Emissions from Electricity Consumption in Maryland*



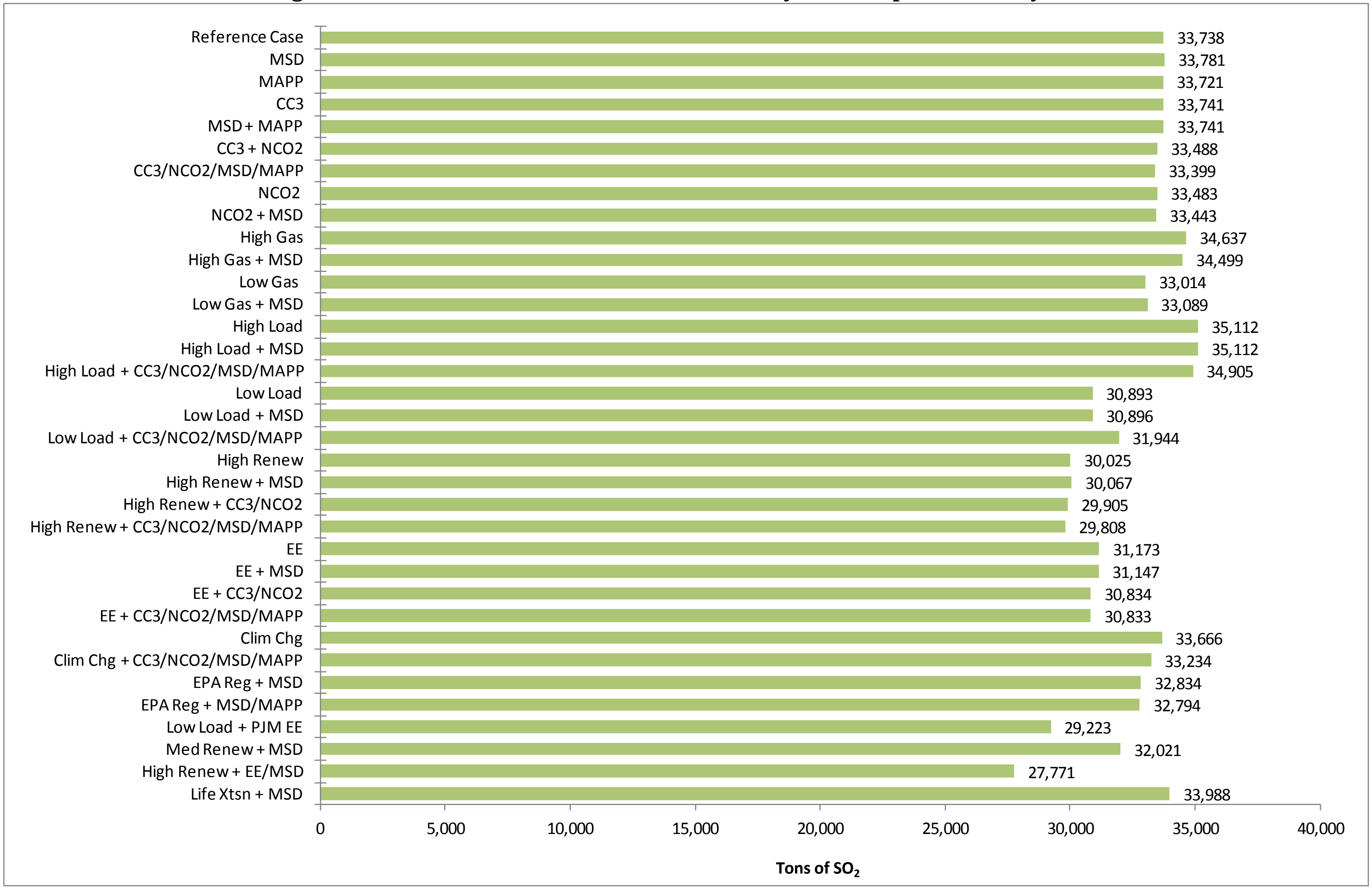
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.2 2020 SO_2 Emissions from Electricity Consumption in Maryland*



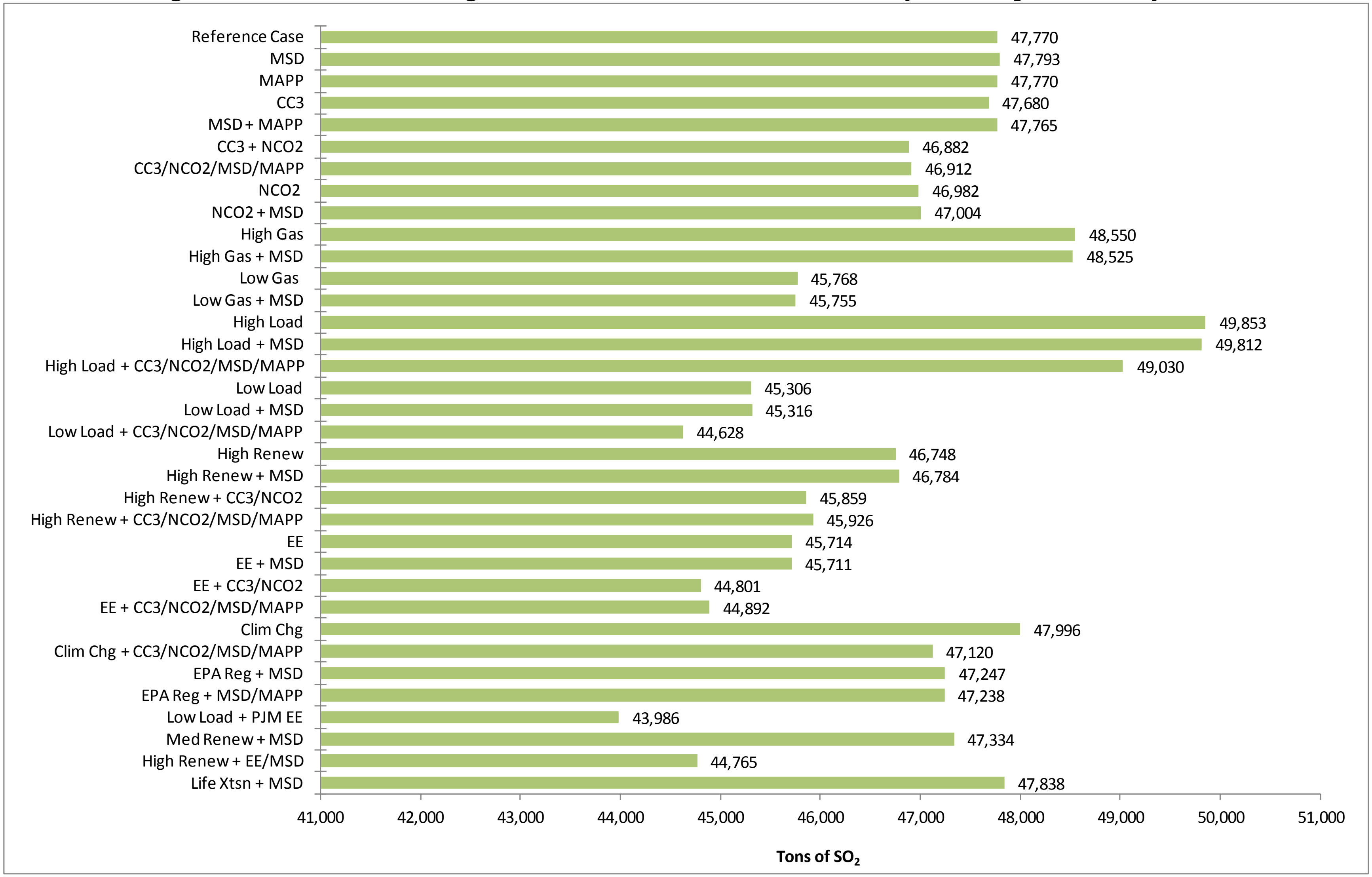
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.3 2030 SO_2 Emissions from Electricity Consumption in Maryland*



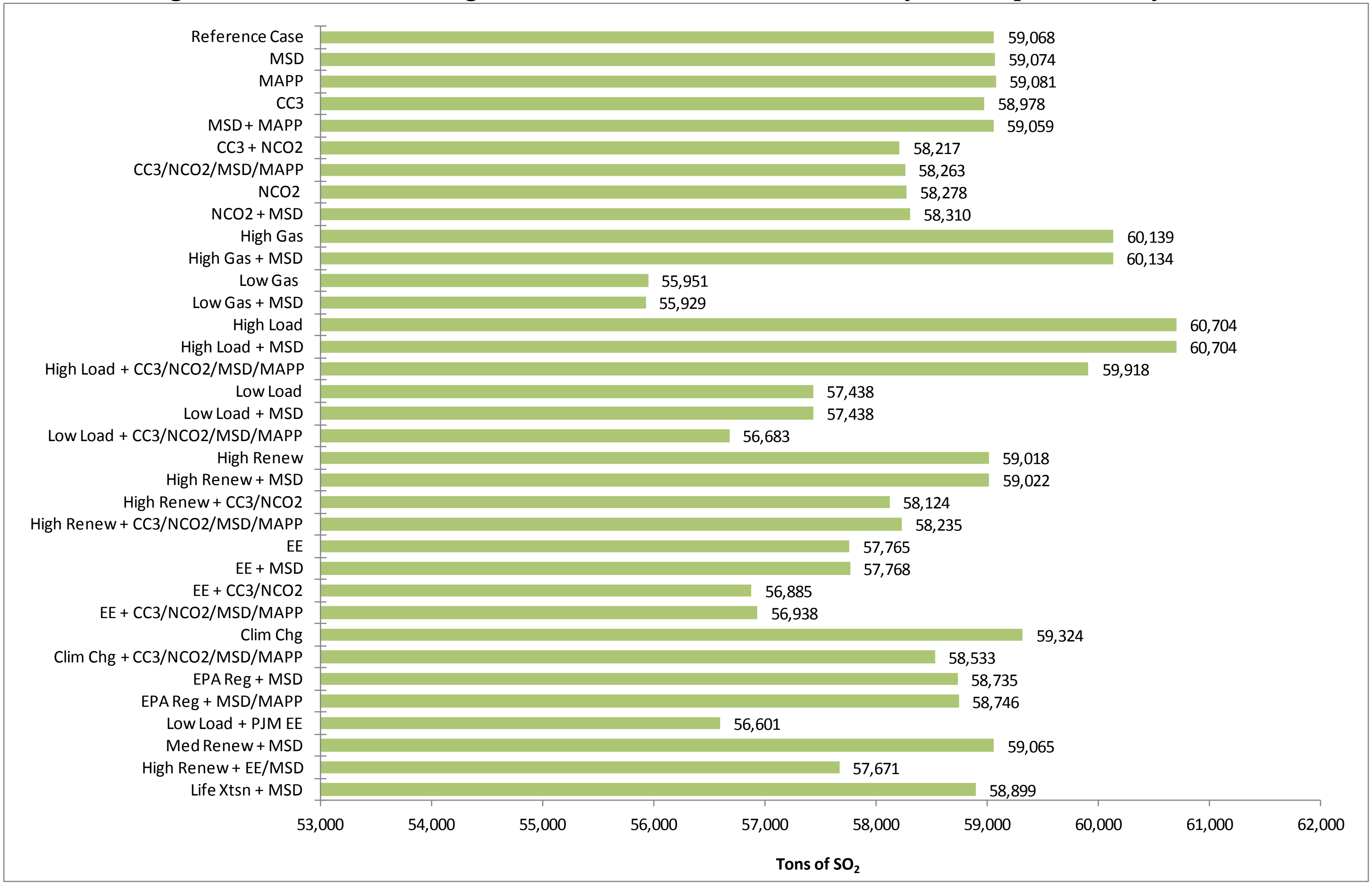
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.4 2010-2030 Average Annual SO_2 Emissions from Electricity Consumption in Maryland*



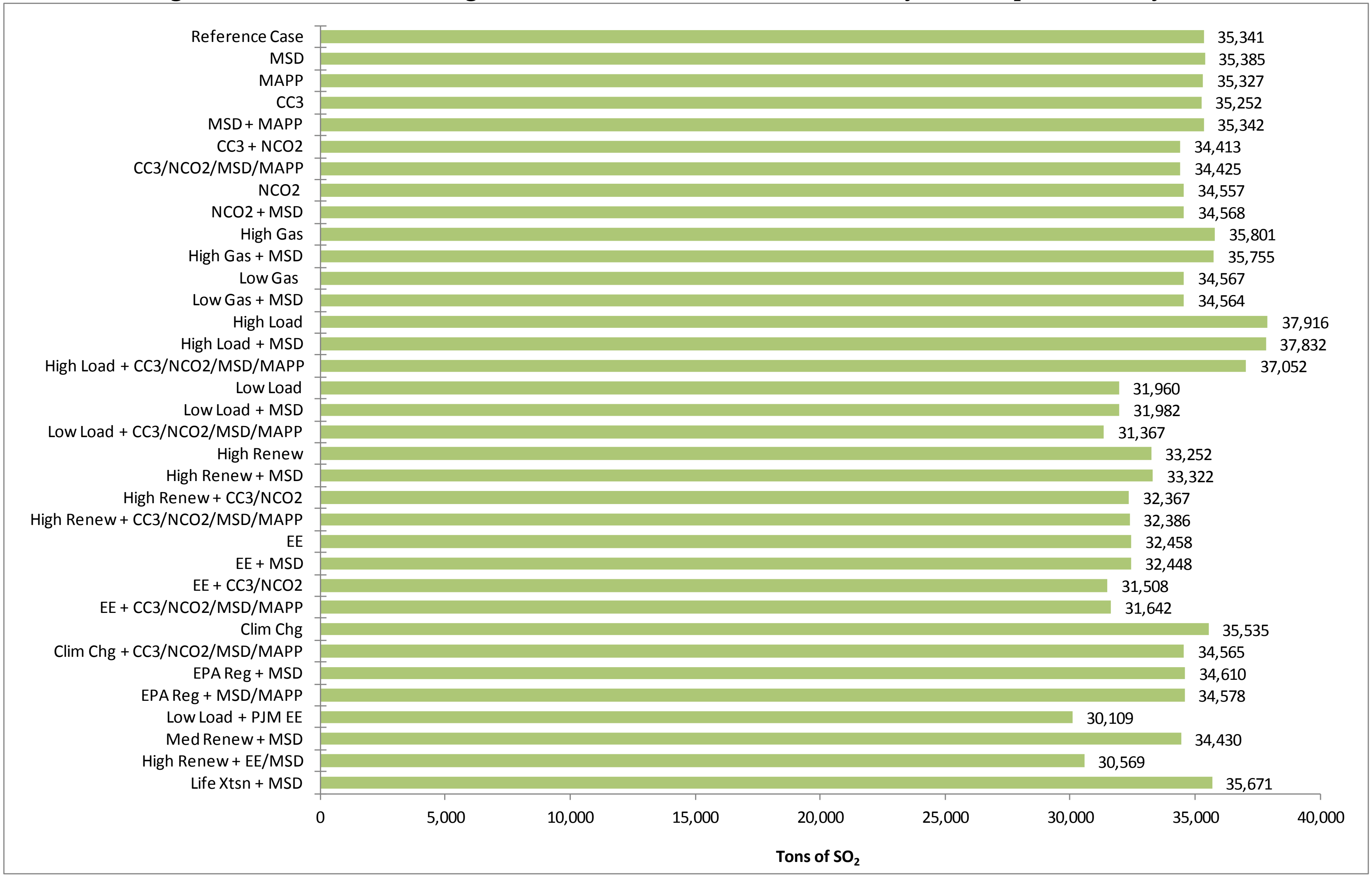
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.5 2010-2020 Average Annual SO_2 Emissions from Electricity Consumption in Maryland*



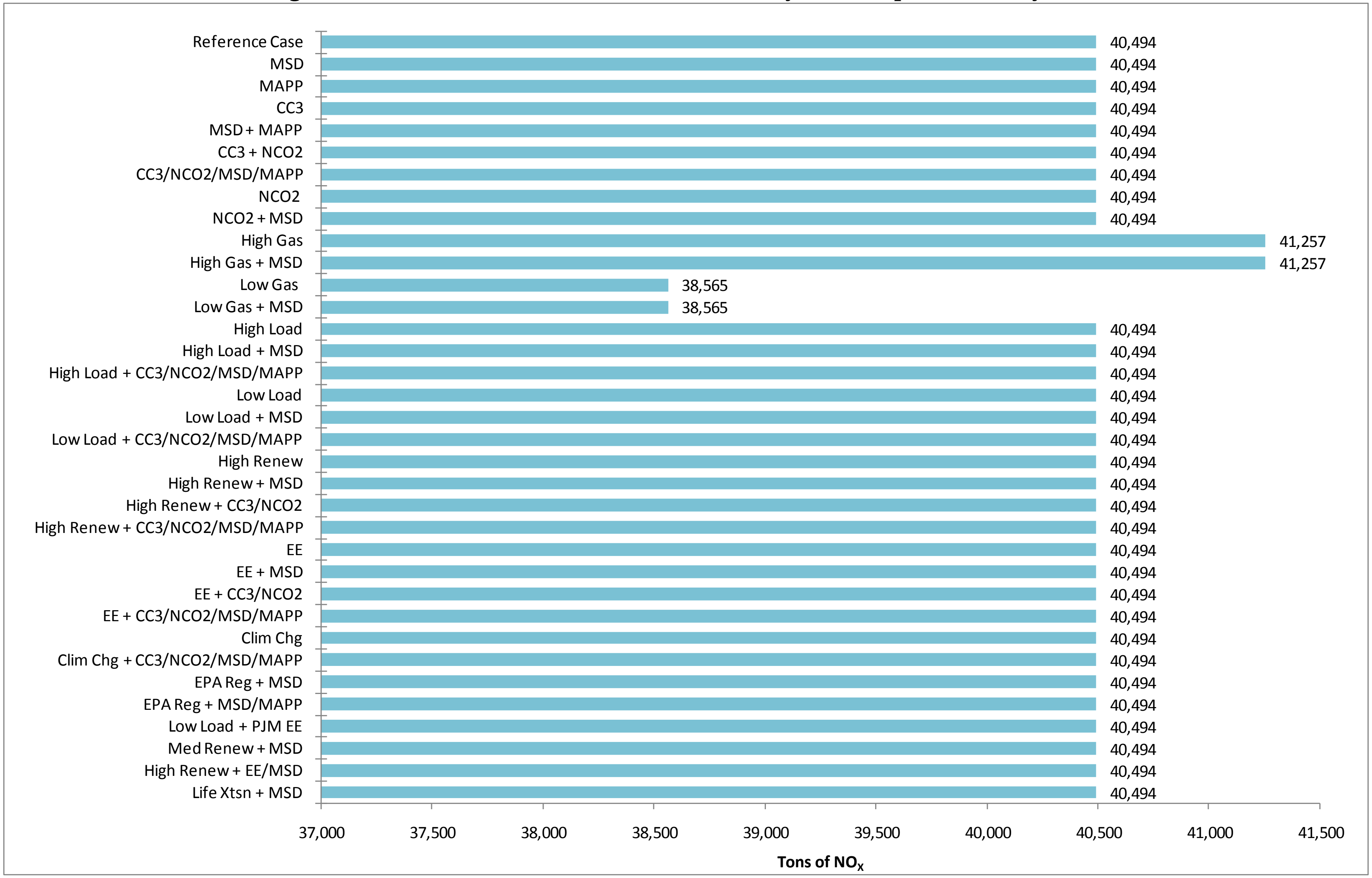
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.6 2021-2030 Average Annual SO_2 Emissions from Electricity Consumption in Maryland*



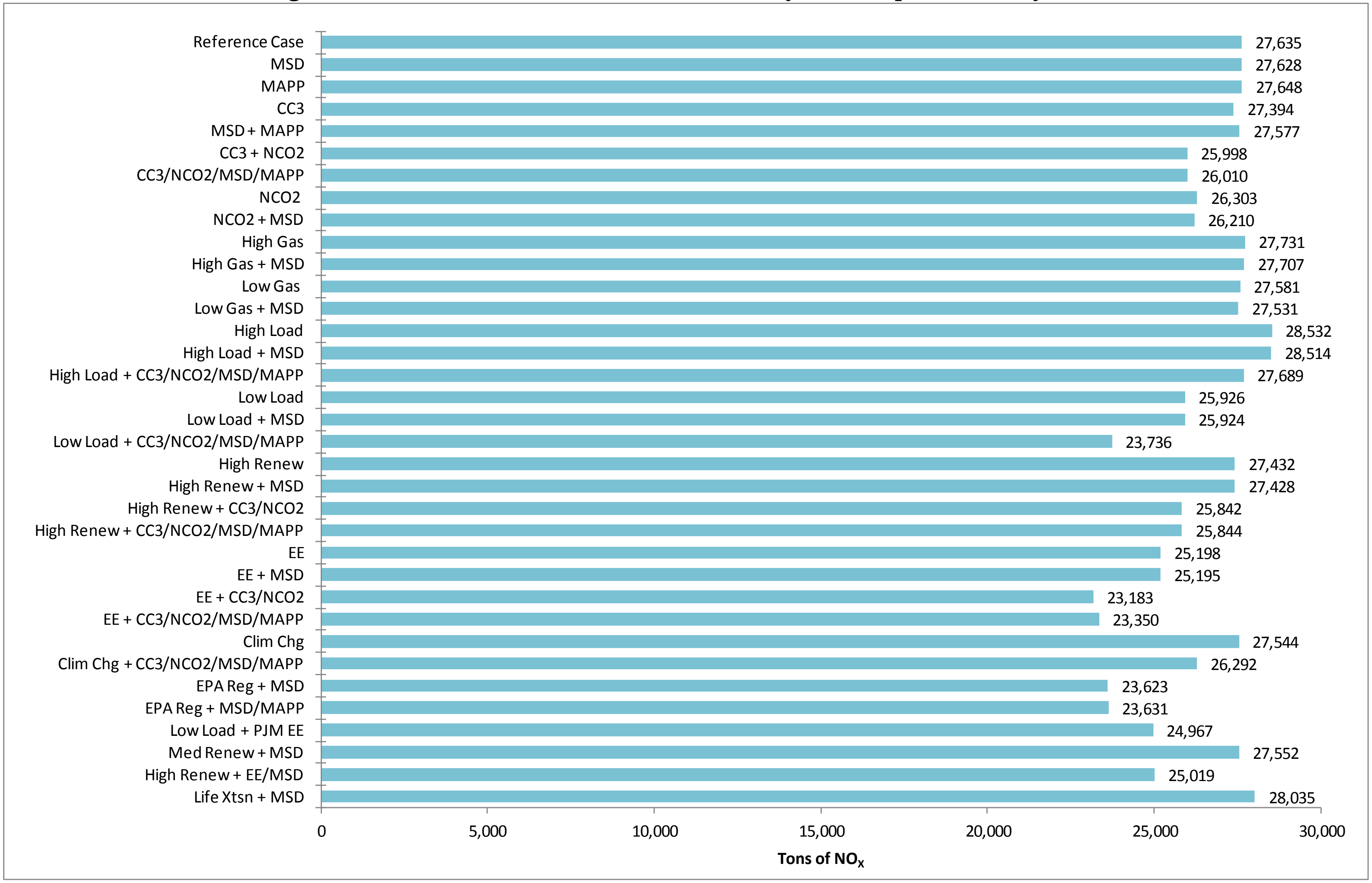
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.7 2010 NO_x Emissions from Electricity Consumption in Maryland*



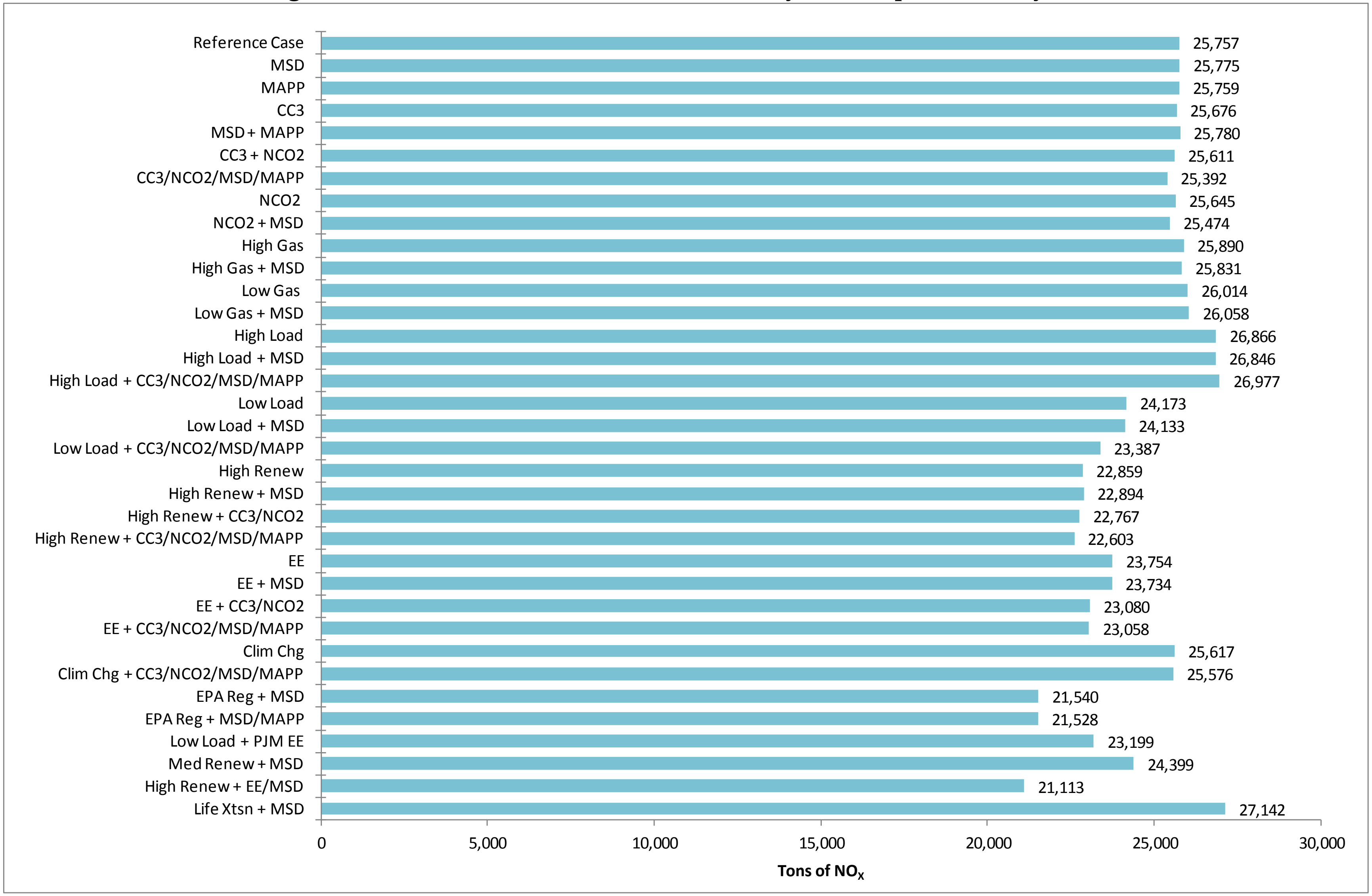
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.8 2020 NO_x Emissions from Electricity Consumption in Maryland*



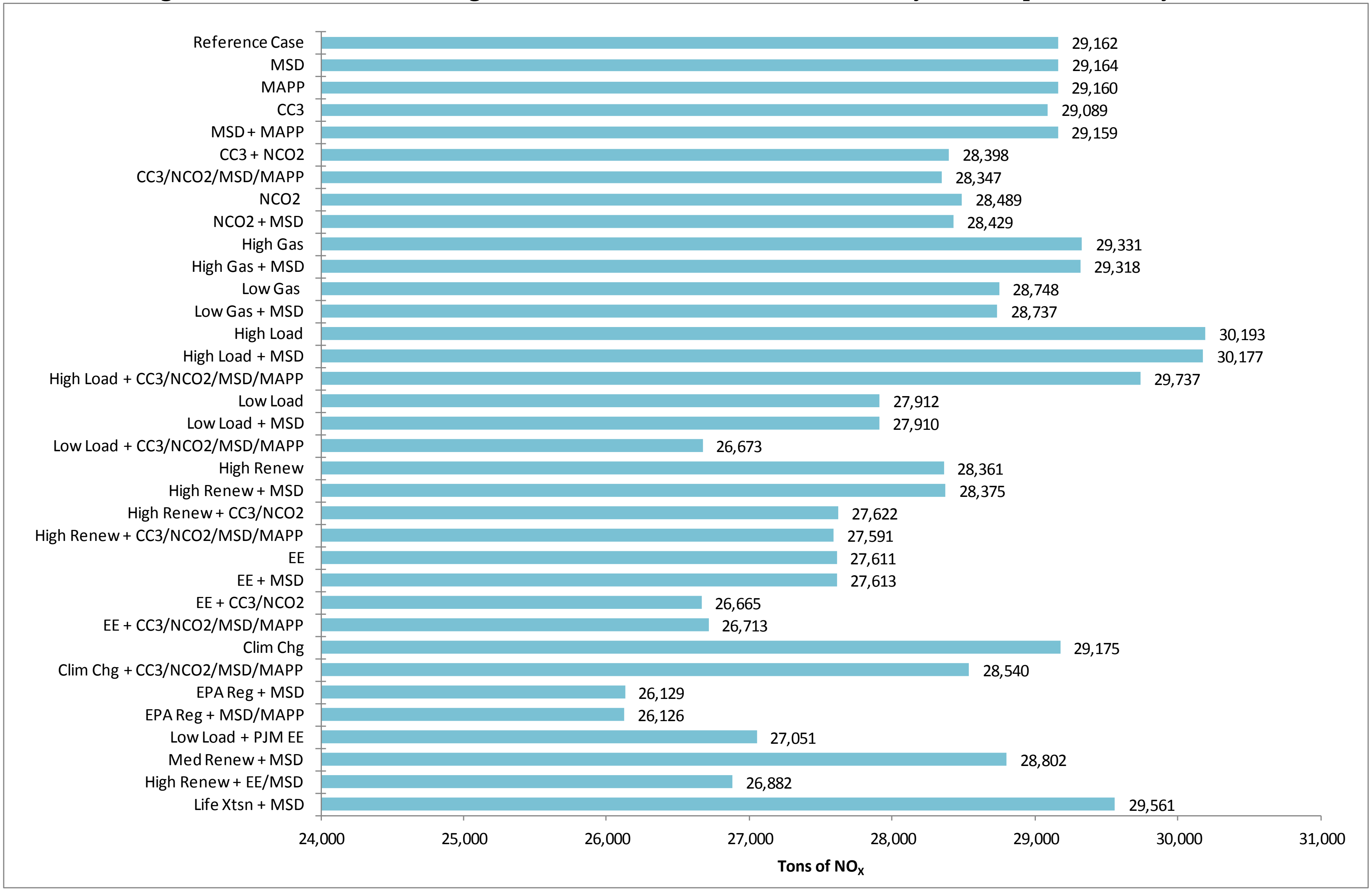
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.9 2030 NO_x Emissions from Electricity Consumption in Maryland*



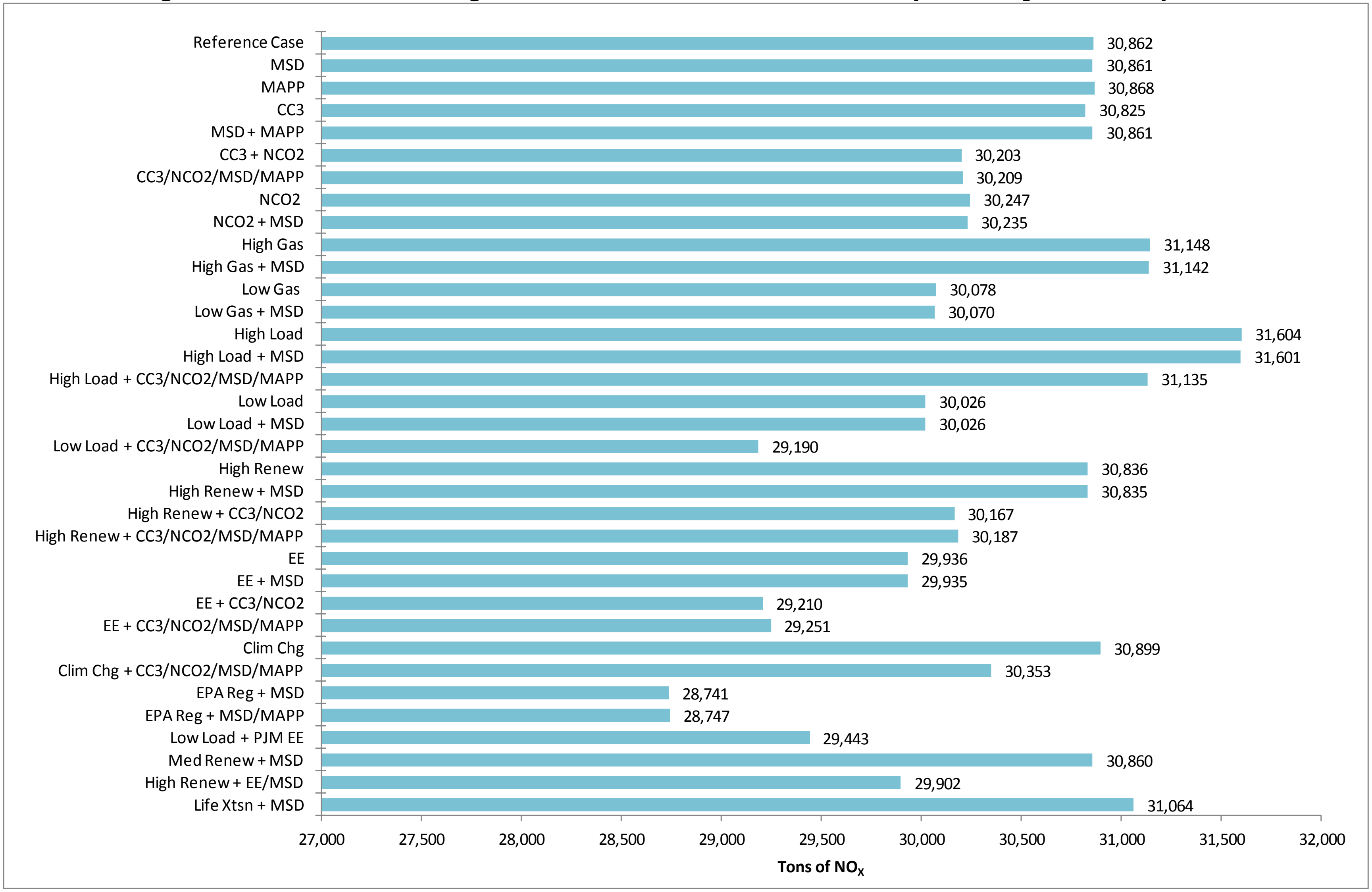
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.10 2010-2030 Average Annual NO_x Emissions from Electricity Consumption in Maryland*



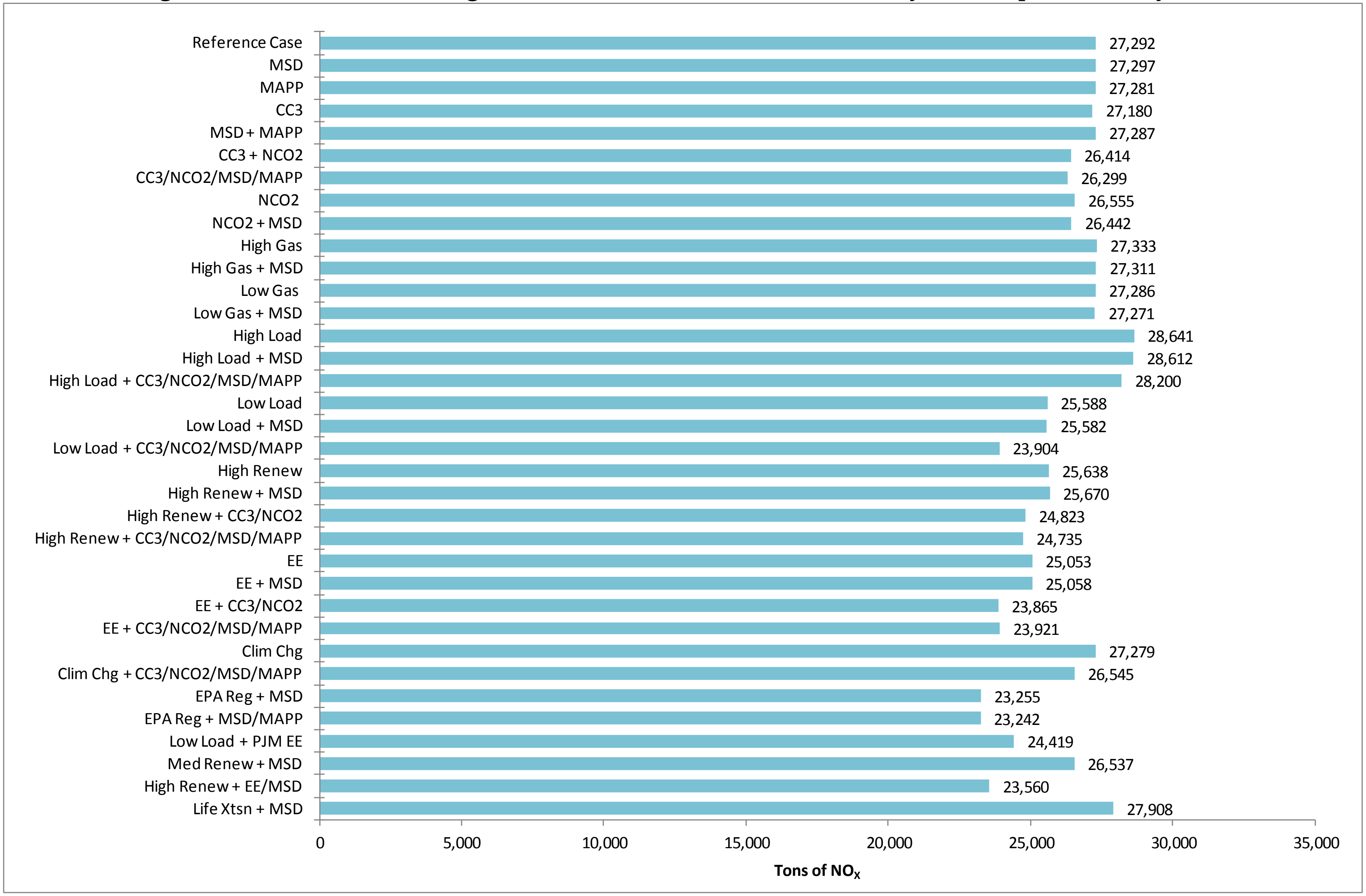
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.11 2010-2020 Average Annual NO_x Emissions from Electricity Consumption in Maryland*



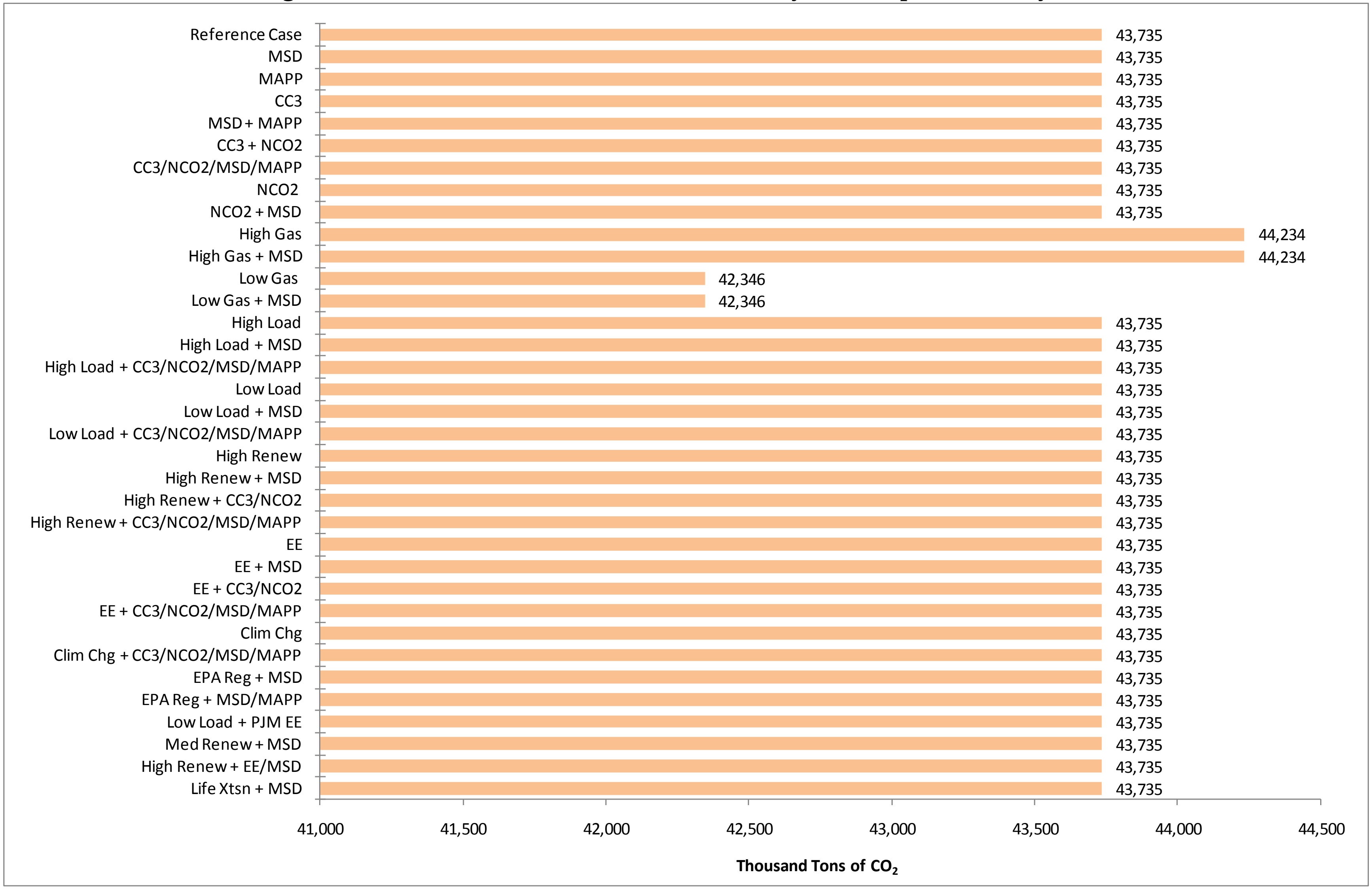
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.12 2021-2030 Average Annual NO_x Emissions from Electricity Consumption in Maryland*



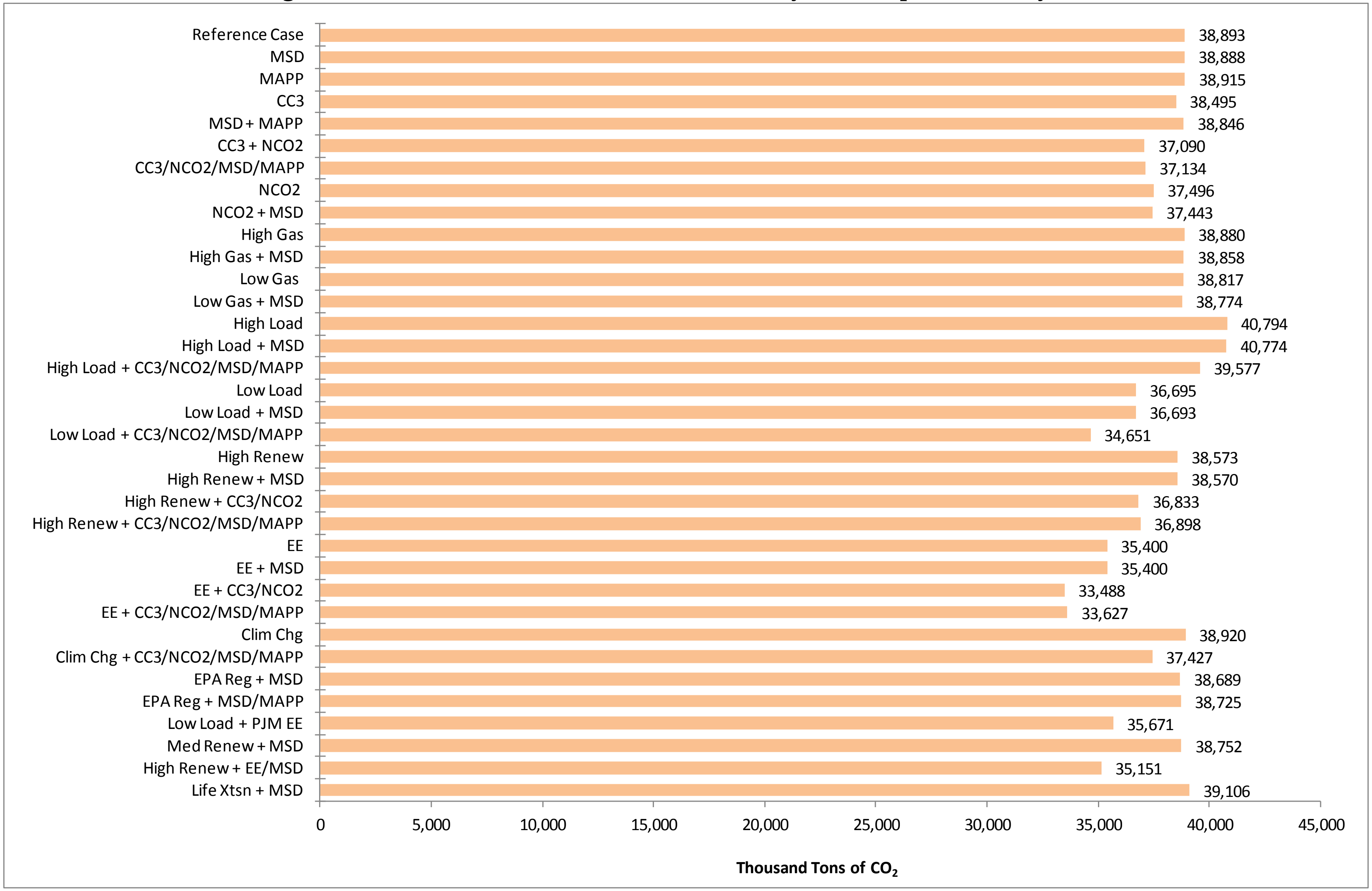
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.13 2010 CO_2 Emissions from Electricity Consumption in Maryland*



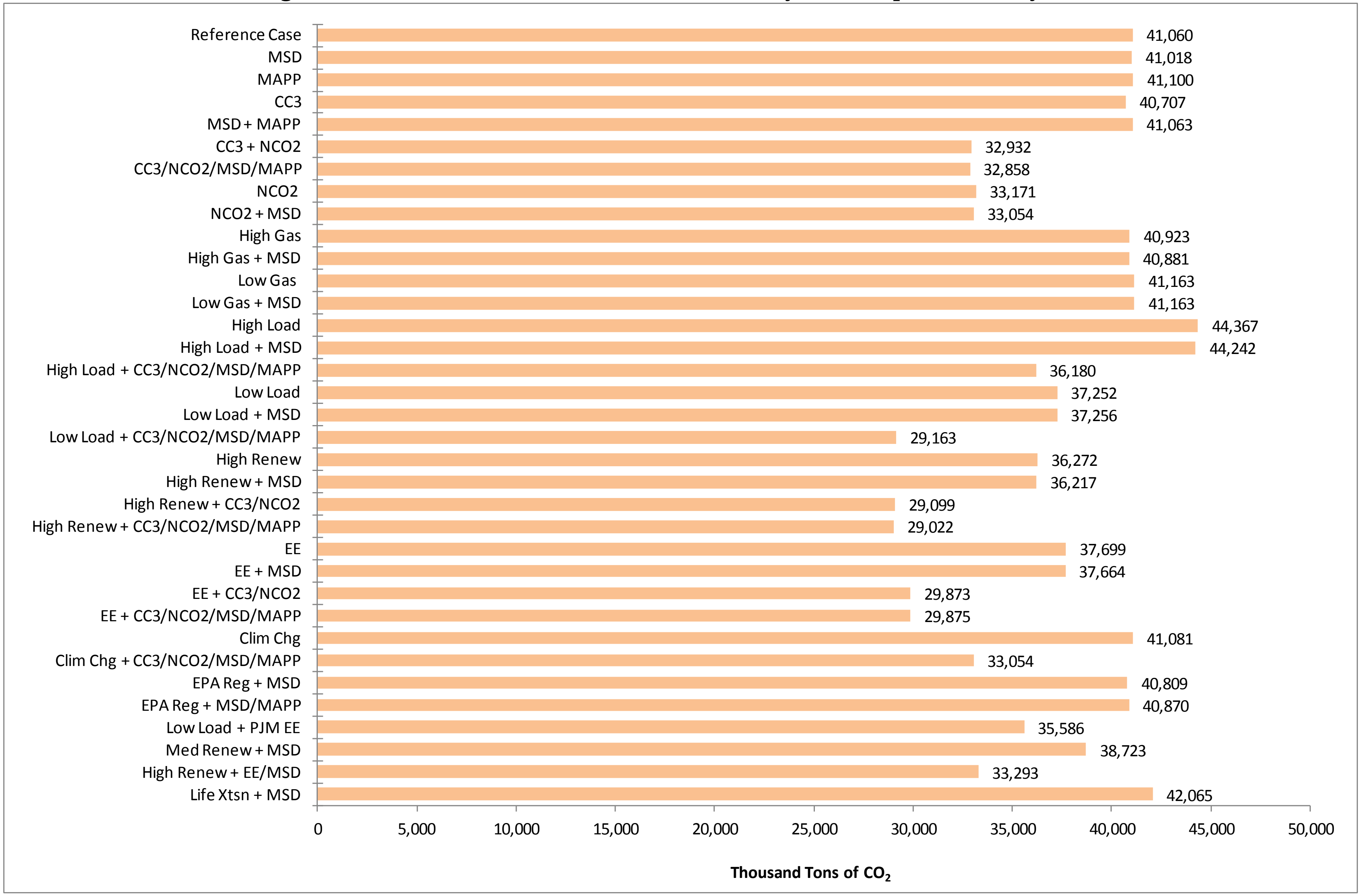
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.14 2020 CO_2 Emissions from Electricity Consumption in Maryland*



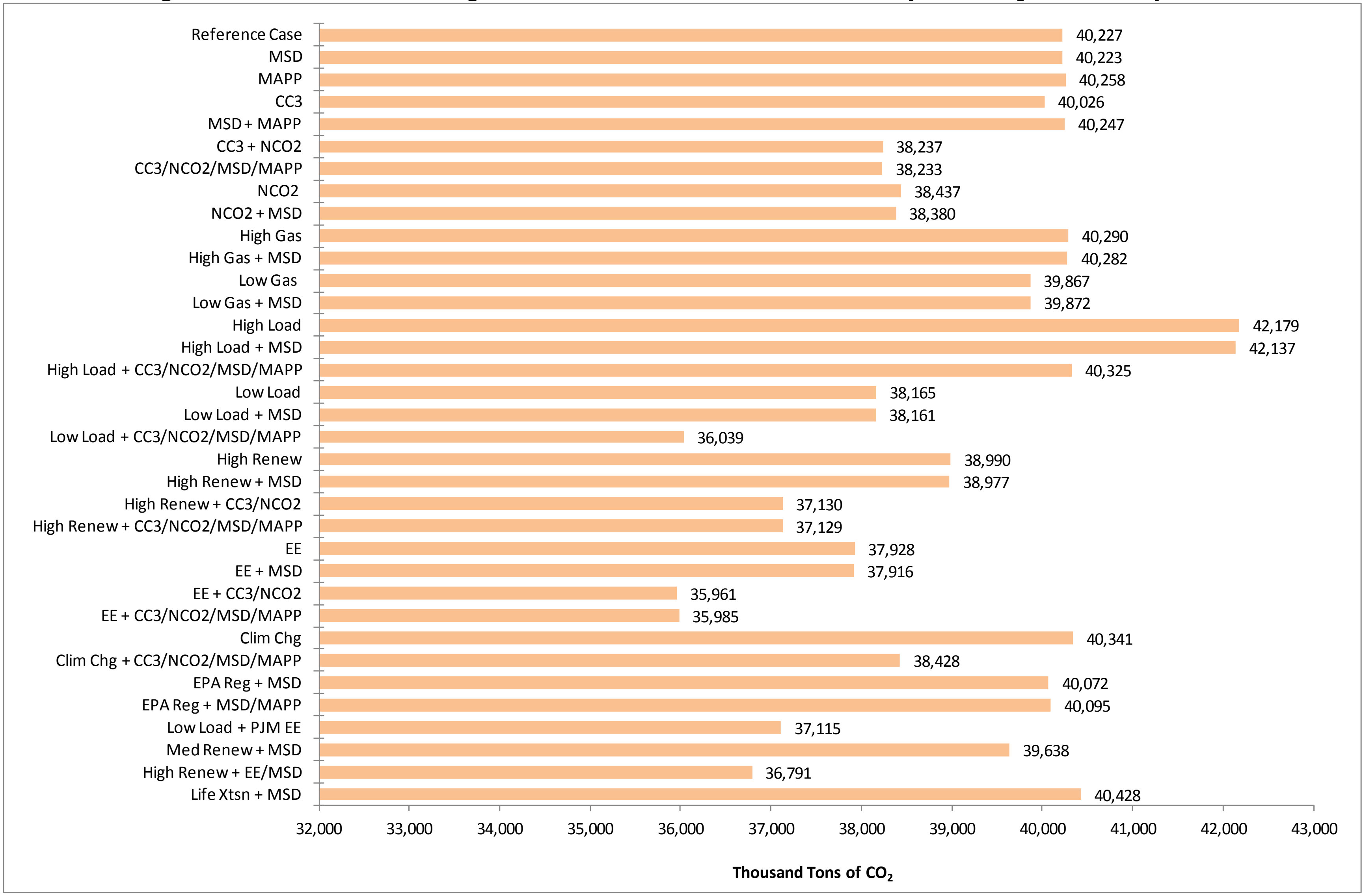
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.15 2030 CO_2 Emissions from Electricity Consumption in Maryland*



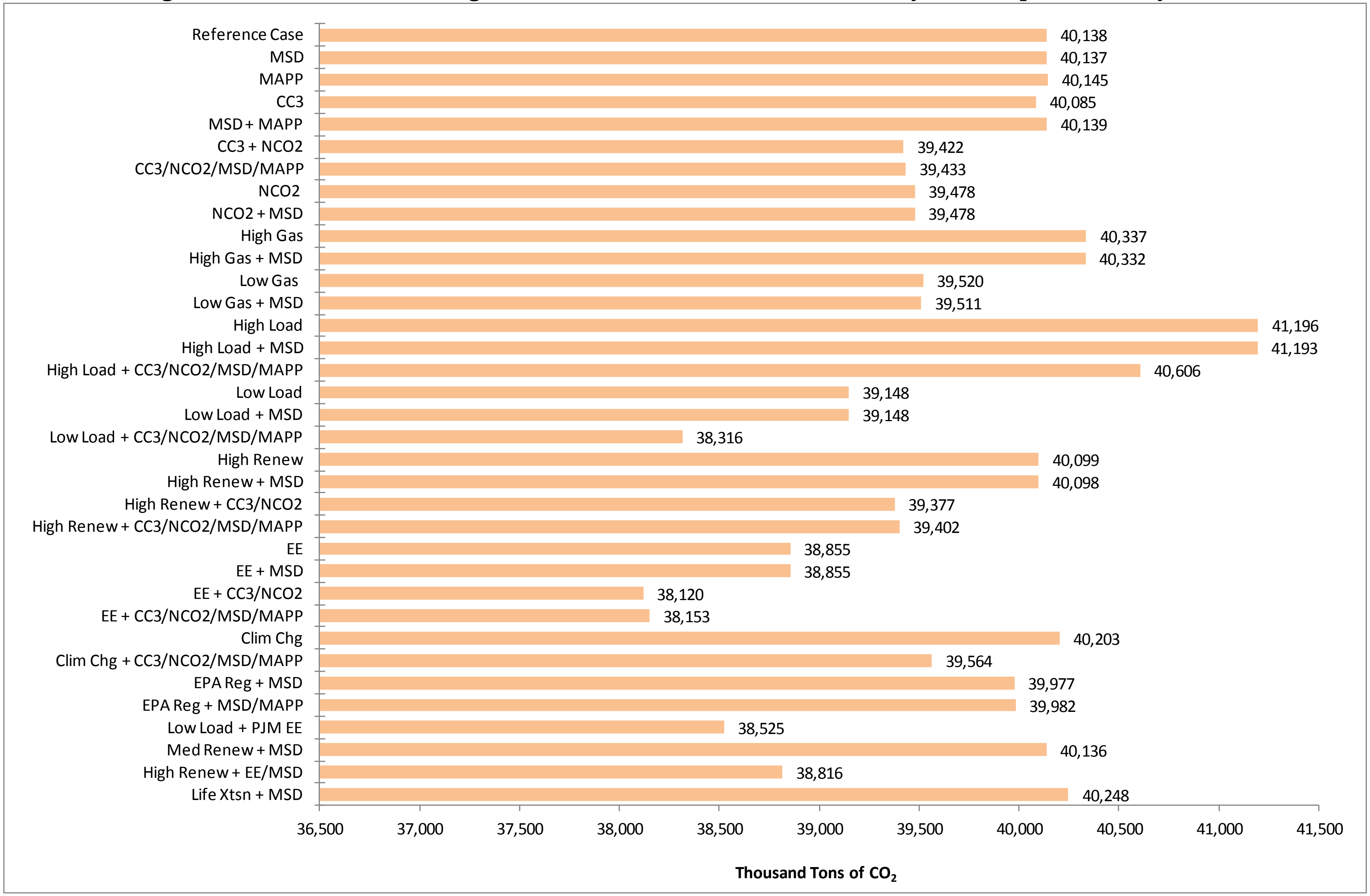
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.16 2010-2030 Average Annual CO_2 Emissions from Electricity Consumption in Maryland*



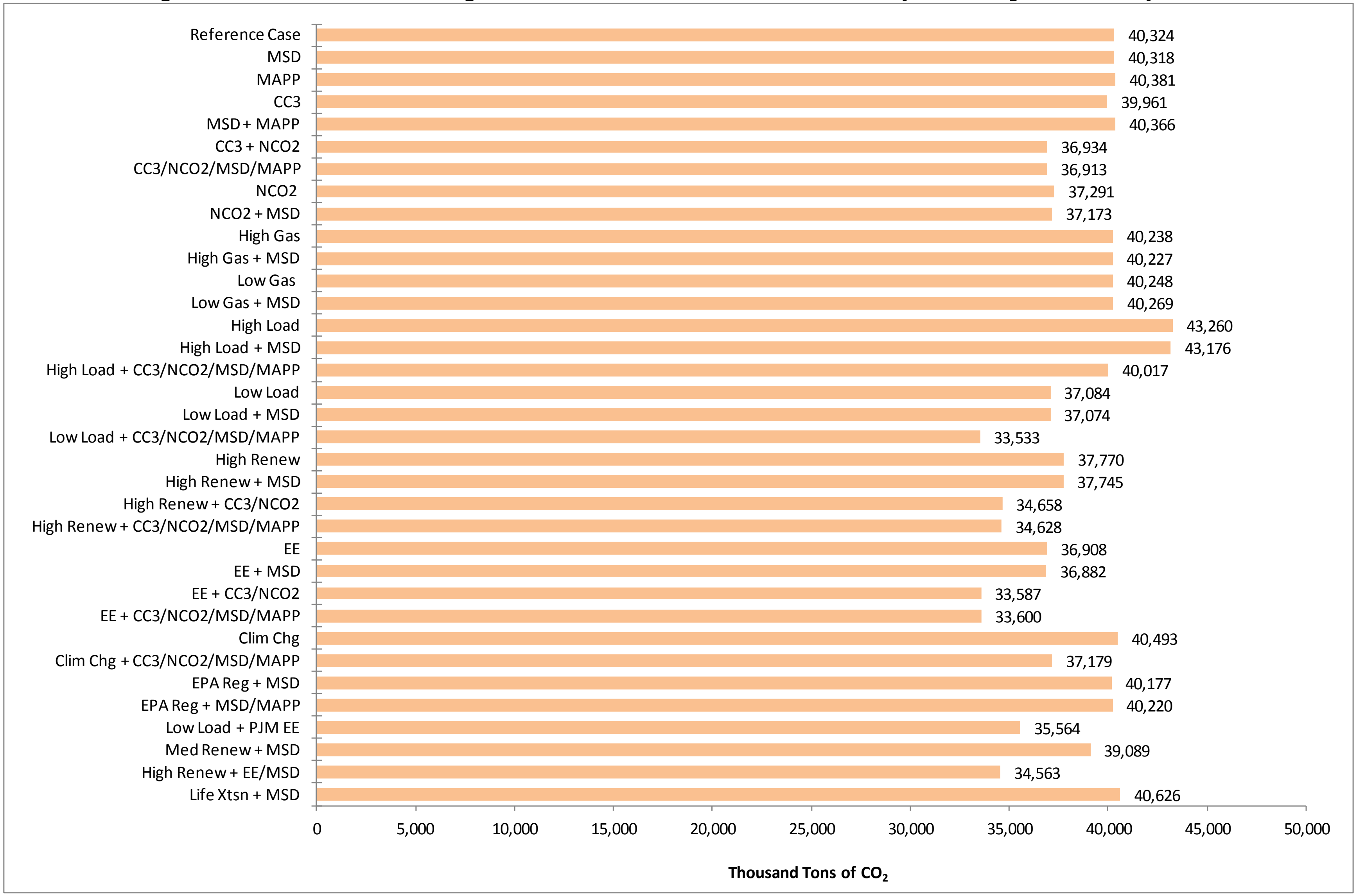
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.17 2010-2020 Average Annual CO_2 Emissions from Electricity Consumption in Maryland*



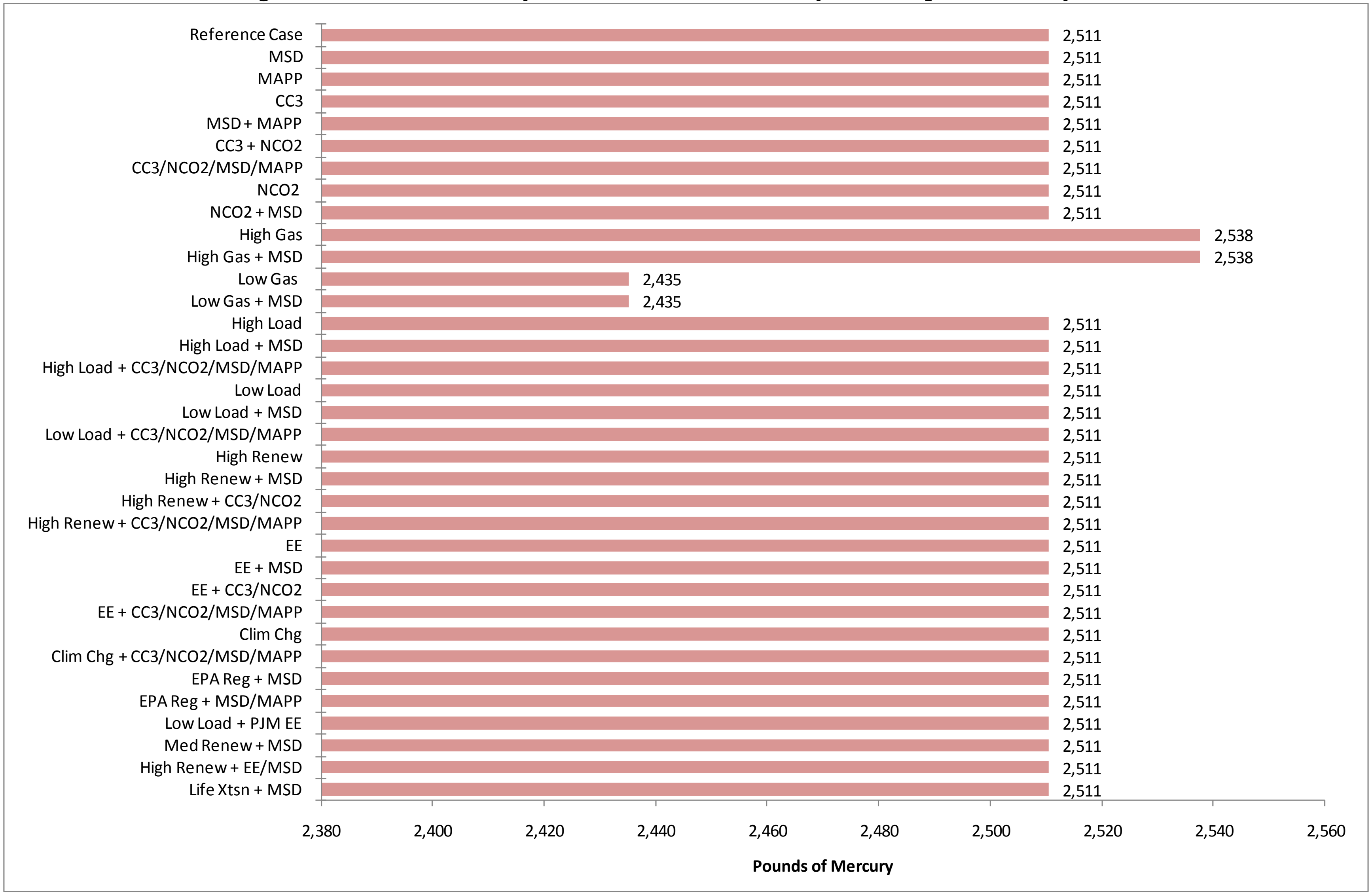
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.18 2021-2030 Average Annual CO_2 Emissions from Electricity Consumption in Maryland*



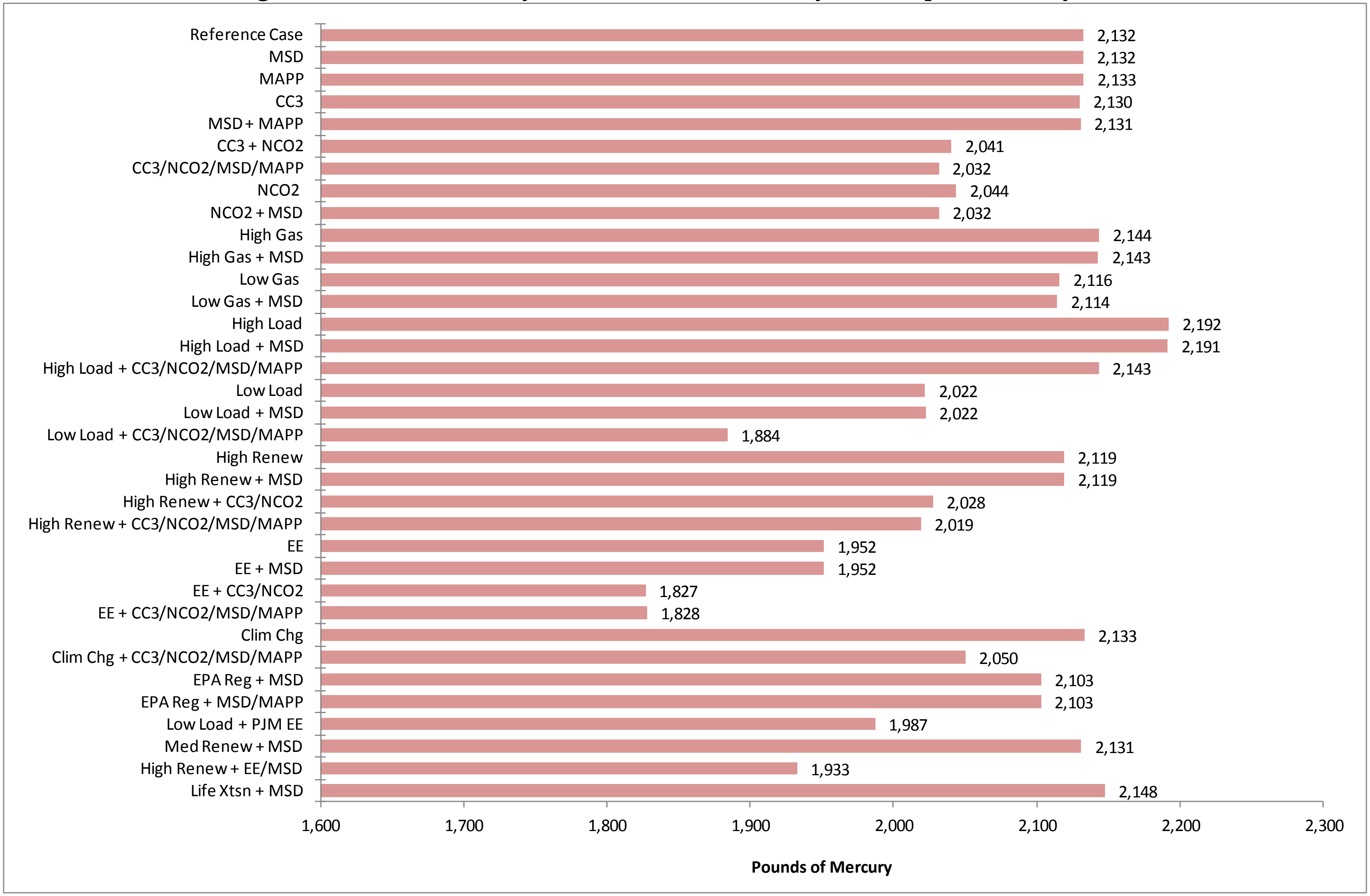
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.19 2010 Mercury Emissions from Electricity Consumption in Maryland*



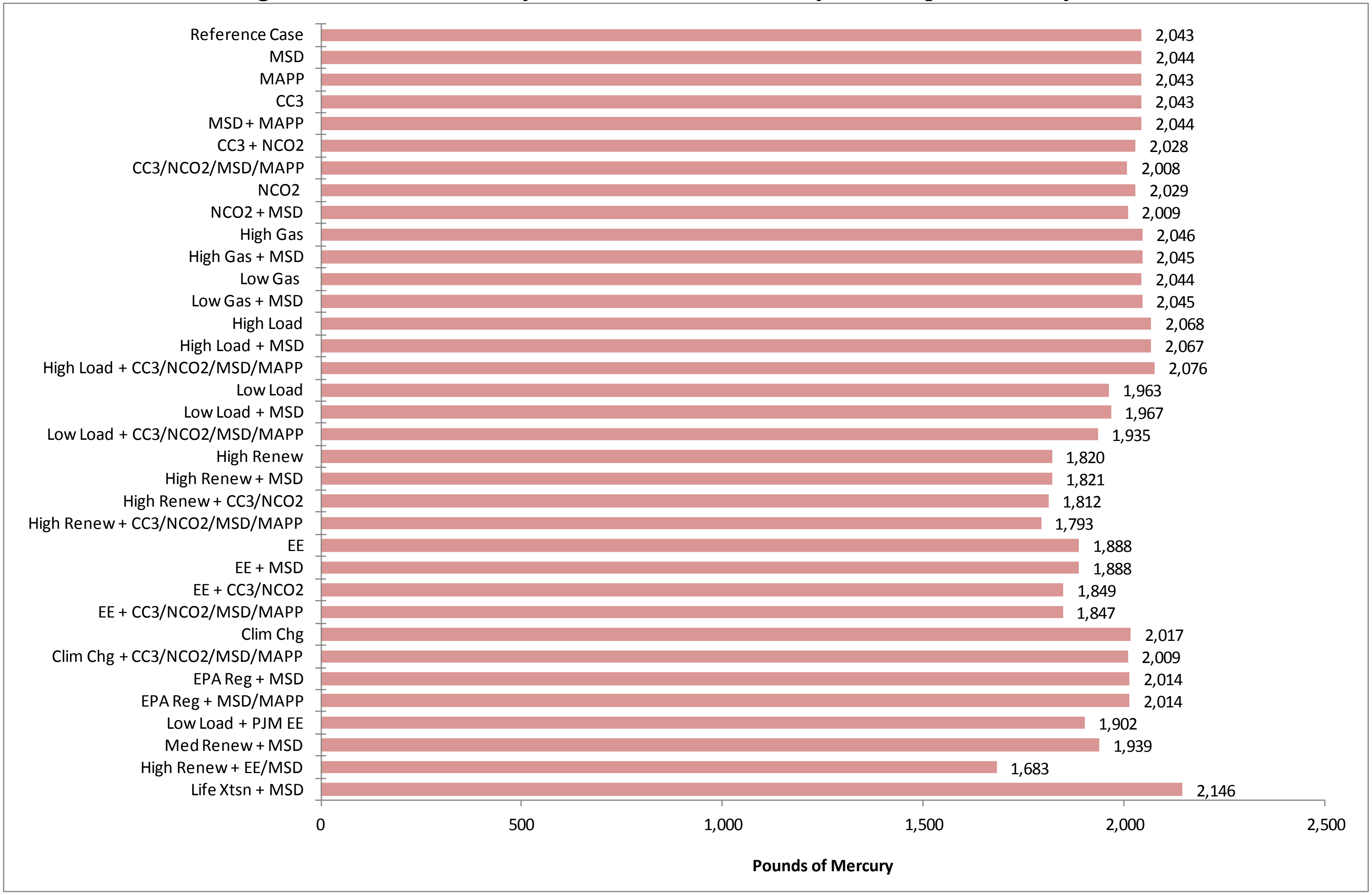
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.20 2020 Mercury Emissions from Electricity Consumption in Maryland*



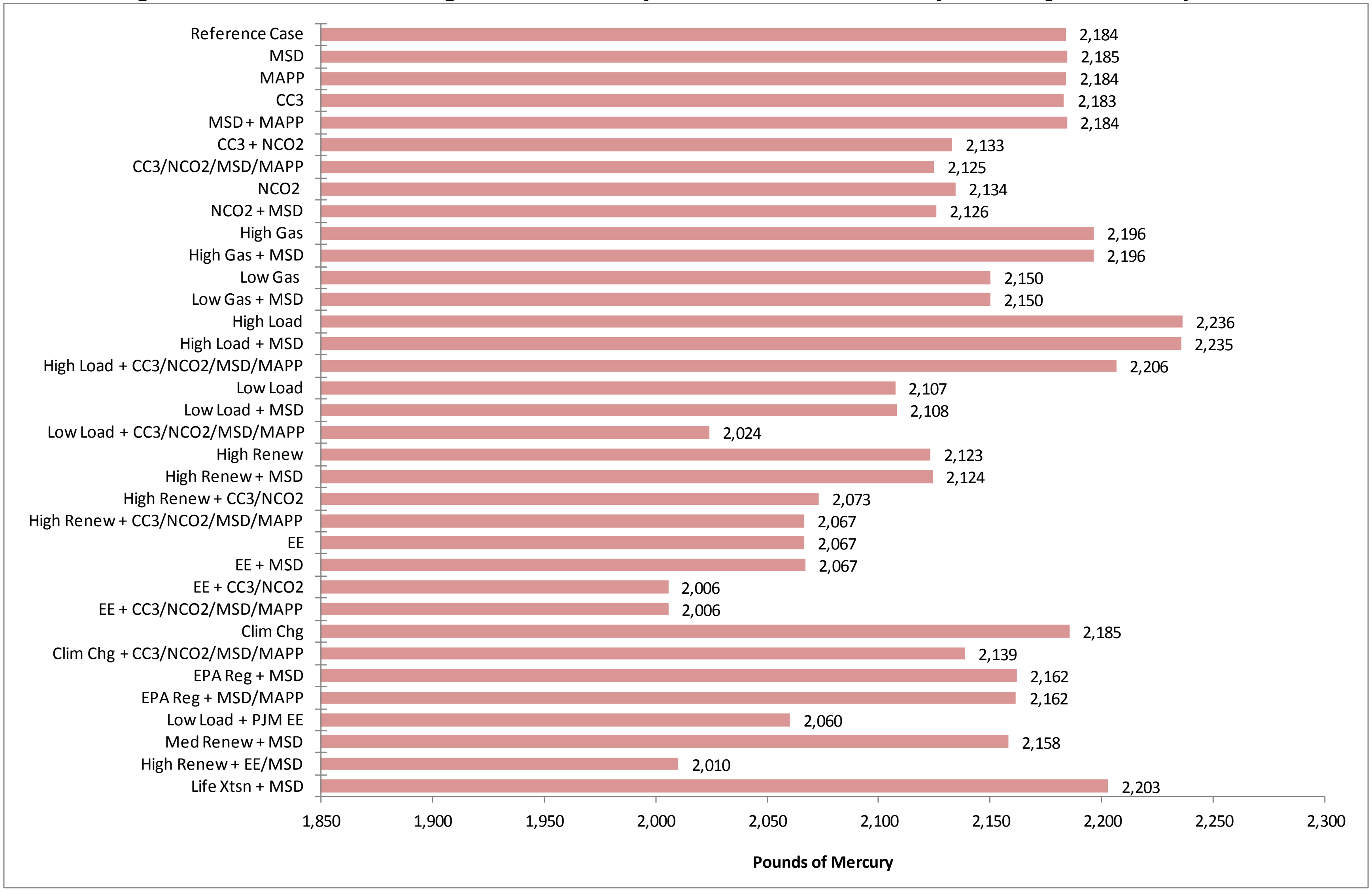
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.21 2030 Mercury Emissions from Electricity Consumption in Maryland*



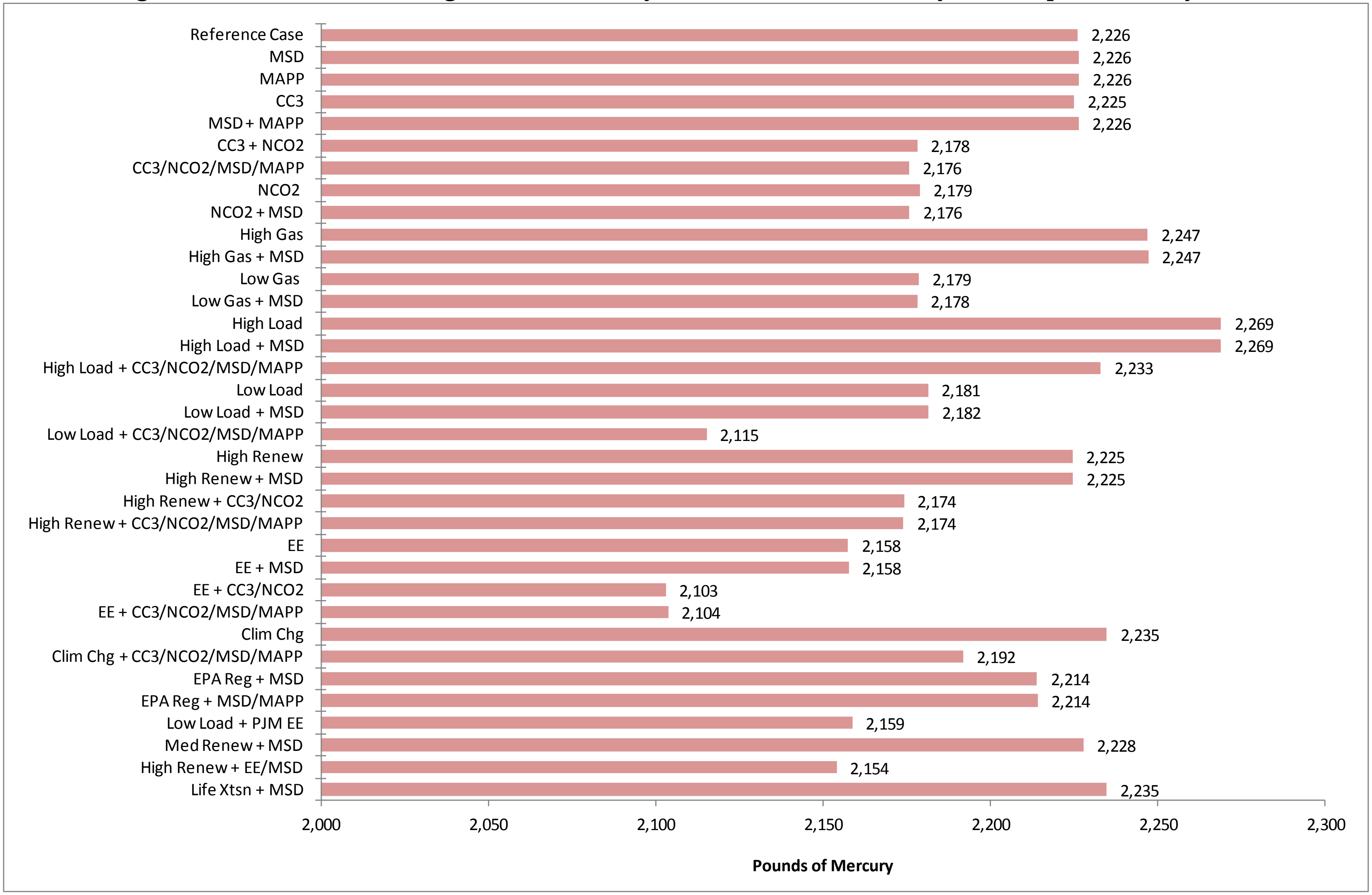
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.22 2010-2030 Average Annual Mercury Emissions from Electricity Consumption in Maryland*



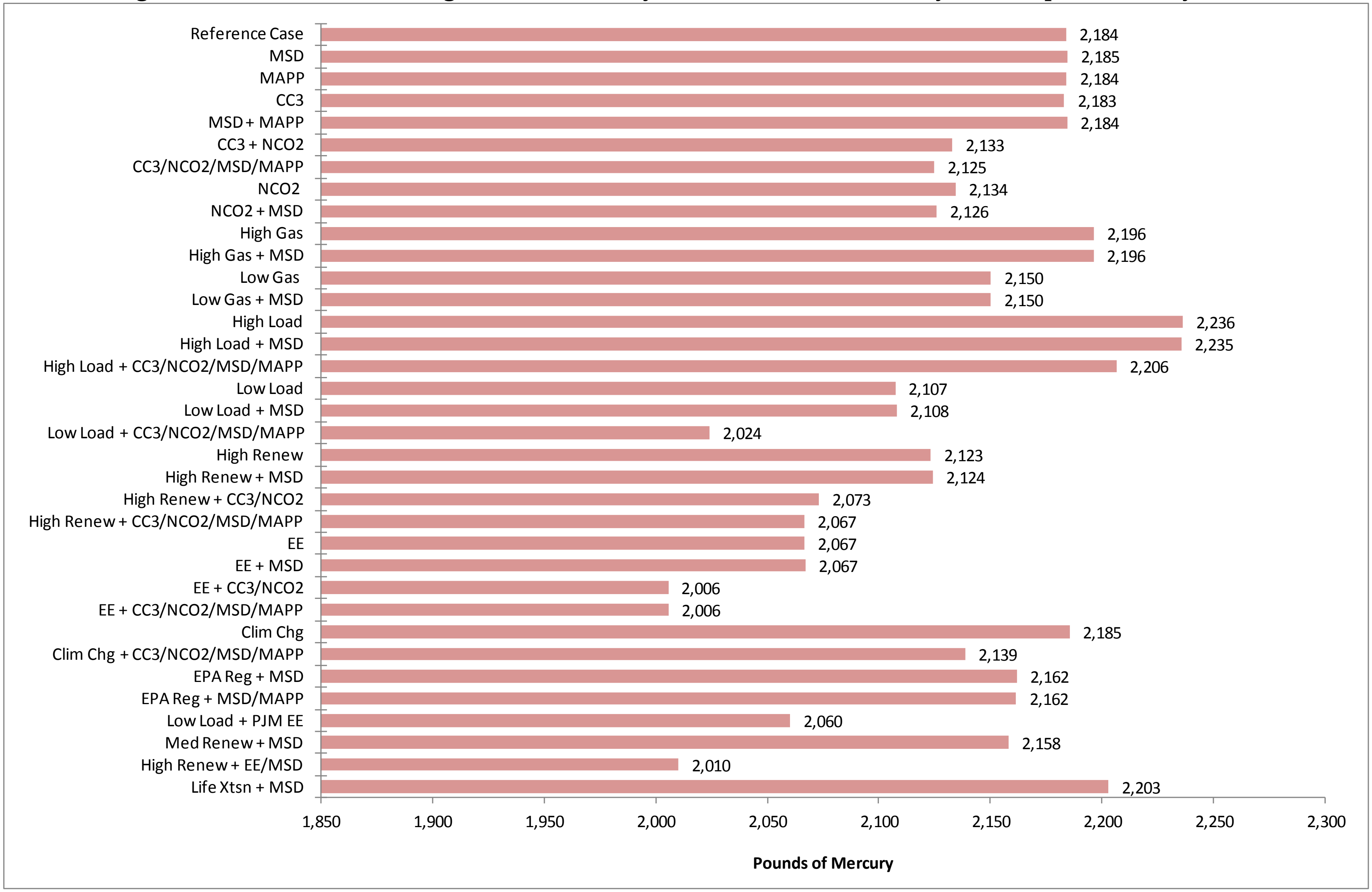
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.23 2010-2020 Average Annual Mercury Emissions from Electricity Consumption in Maryland*



*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.24 2021-2030 Average Annual Mercury Emissions from Electricity Consumption in Maryland*



*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

14.4.3 LTER Reference Case Results

Average annual SO_2 emissions in the LTER Reference Case is estimated to be approximately 48,000 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 29,000 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 Cross-State Air Pollution Rule ("CSAPR"), which restricts emissions of SO_2 and NO_x throughout the U.S., 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 CSAPR comes into effect).

There is a smaller difference between CO_2 emissions from consumption and from generation than is 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 40 million tons during the study period. This level compares to an annual average of approximately 32 million 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 2,200 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).

Note that in the LTER Reference Case, by 2030, SO_2 emissions levels are reduced to about 26 percent of 2010 levels. The modeling results indicate less significant changes for the other pollutants. 2030 emissions levels as a percentage of 2010 levels equal about 63 percent for NO_x, 94 percent for CO_2, and 81 percent for mercury, respectively.

14.4.4 Alternative Transmission Scenarios

In each of the alternative transmission scenarios (MSD, MAPP, and 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.

14.4.5 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 also include a national RPS) result in more natural gas-fired capacity additions relative to the LTER Reference Case, SO_2, NO_x, and mercury emissions are reduced because natural gas plants emit less of each of theses pollutants than coal plants. In the two scenarios that include both high renewables and national carbon legislation, the results indicate that this combination will induce significant reductions in consumption-based emissions of all four pollutants.

14.4.6 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) if a third nuclear unit is constructed at the Calvert Cliffs site.

14.4.7 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 natural 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 in response to a given percentage change in price (over time, if electricity prices increase, consumers will typically consume less electricity). 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.

14.4.8 Energy Efficiency Scenarios

The energy efficiency scenario results in decreased emissions among all four pollutants, relative to the LTER Reference Case. The energy efficiency and conservation assumptions result in reduced energy consumption levels in Maryland. Thus, with lower in-State electricity demand, we observe less consumption-based emissions in Maryland. The two energy efficiency scenarios that include national carbon legislation result in significantly lower emissions, relative to the LTER Reference Case. Less energy consumption in Maryland coupled with a lower-emitting fleet of PJM power plants, significantly reduces consumption-based emissions in the State.

14.4.9 Climate Change Scenarios

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

14.4.10 High and Low Load Growth Scenarios

Under the high load growth scenarios, the modeling results indicate higher levels of all four pollutants in comparison to the LTER Reference Case. The higher emissions levels can be attributed to the higher levels of energy consumption because PJM plants run more to meet the higher demand levels and, therefore, pollute more. The opposite is true for the low load growth scenarios - PJM plants run less and therefore emit less pollution than in the LTER Reference Case. Note that in the Low Load + CC3/NCO2/MSD/MAPP scenario, emissions levels are significantly lower than in the LTER Reference Case, resulting from the combination of low load growth, national carbon legislation, a national RPS, and an additional nuclear generating unit at Calvert Cliffs.

The Low Load and PJM-wide Energy Efficiency scenario also results in decreased levels of all four pollutants, relative to the LTER Reference Case. The assumption of significantly lower levels of energy consumption means that PJM plants produce less electricity and therefore emit less pollution during the study period.

14.4.11 New EPA Regulations and PPRAC-Identified Additional Scenarios

In the scenarios that include the proposed EPA regulations, the modeling results indicate that all four pollutant levels are lower than under the LTER Reference Case. Under the Medium Renewables scenario, we also see reductions in the levels of all four pollutants, relative to the LTER Reference Case. As expected, the Medium Renewables emissions levels are between those observed in the LTER Reference Case and the High Renewables scenarios.

In the Plant Life Extension scenario, the need for new capacity is delayed a few years because some of the existing capacity stays on-line longer. Because new natural gas plants emit less than older generating units, the average annual emissions levels during the study period are higher than in the LTER Reference Case.

The four Supplemental Responsive Scenarios presented in Appendix L include three scenarios that incorporate new EPA regulations. Emissions for these scenarios are discussed in Appendix L and data are presented in Table L-11 through L-14.

14.4.12 Emissions Tables

Table 14.7 through *The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Table 14.10 show the estimated levels of emissions from electricity consumption in Maryland for each pollutant, by year for each of the scenarios presented in the main body of the LTER.[62]

[62] The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L, Table L-11 through Table L-14.

Table 14.7 Annual SO_2 Emissions from Electricity Consumption in Maryland (tons)*

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Reference Case	127,900	109,597	84,787	58,724	49,738	39,555	36,857	35,885	35,448	35,379	35,879
MSD	127,900	109,600	84,790	58,727	49,740	39,572	36,877	35,887	35,453	35,390	35,875
MAPP	127,900	109,600	84,790	58,727	49,740	39,558	36,860	35,887	35,492	35,423	35,916
CC3	127,900	109,597	84,787	58,724	49,738	39,555	36,857	35,885	35,448	34,828	35,434
MSD + MAPP	127,900	109,600	84,790	58,727	49,740	39,572	36,877	35,887	35,513	35,434	35,609
CC3 + NCO2	127,900	109,598	84,798	58,682	49,697	38,137	36,082	34,524	33,800	33,349	33,825
CC3/NCO2/MSD/MAPP	127,900	109,598	84,798	58,682	49,697	38,165	36,147	34,525	33,883	33,503	33,996
NCO2	127,900	109,598	84,798	58,682	49,697	38,137	36,082	34,524	33,800	33,553	34,286
NCO2 + MSD	127,900	109,598	84,798	58,682	49,697	38,165	36,147	34,525	33,821	33,793	34,283
High Gas	130,669	111,125	86,885	60,282	50,639	40,181	37,169	36,280	35,916	35,972	36,413
High Gas + MSD	130,669	111,125	86,885	60,282	50,639	40,192	37,192	36,285	35,890	35,943	36,368
Low Gas	119,974	103,312	78,058	54,147	46,535	37,821	35,854	35,368	34,770	34,329	35,290
Low Gas + MSD	119,974	103,312	78,058	54,147	46,535	37,835	35,866	35,373	34,768	34,264	35,088
High Load	127,900	110,202	85,907	59,954	51,230	41,486	38,945	38,909	37,957	37,500	37,760
High Load + MSD	127,900	110,202	85,907	59,954	51,230	41,505	38,969	38,908	37,946	37,488	37,735
High Load + CC3/NCO2/MSD/MAPP	127,900	110,206	85,950	59,839	51,114	39,597	37,966	37,353	36,567	36,050	36,554
Low Load	127,900	108,929	83,432	57,331	48,153	38,391	35,473	34,363	33,227	32,256	32,365
Low Load + MSD	127,900	108,929	83,432	57,331	48,153	38,391	35,476	34,364	33,217	32,267	32,362
Low Load + CC3/NCO2/MSD/MAPP	127,900	108,934	83,431	57,270	48,142	37,036	34,707	32,627	31,827	30,766	30,873
High Renew	127,900	109,600	84,790	58,727	49,740	39,558	36,860	35,887	35,453	35,270	35,410
High Renew + MSD	127,900	109,600	84,790	58,727	49,740	39,572	36,877	35,887	35,459	35,282	35,408
High Renew + CC3/NCO2	127,900	109,598	84,798	58,682	49,697	38,137	36,082	34,524	33,508	32,870	33,567
High Renew + CC3/NCO2/MSD/MAPP	127,900	109,598	84,798	58,682	49,697	38,165	36,147	34,525	33,882	33,408	33,781
EE	127,900	109,606	84,289	58,098	48,985	38,770	35,650	34,208	32,927	32,403	32,579
EE + MSD	127,900	109,606	84,289	58,098	48,985	38,784	35,665	34,210	32,935	32,400	32,576
EE + CC3/NCO2	127,900	109,607	84,305	58,065	48,949	37,412	34,911	32,785	31,476	30,184	30,139
EE + CC3/NCO2/MSD/MAPP	127,900	109,607	84,305	58,065	48,949	37,439	34,964	32,784	31,537	30,394	30,368
Climate Change	127,900	109,602	84,788	58,723	49,726	39,786	37,441	36,814	36,065	35,761	35,962
Climate Change + CC3/NCO2/MSD/MAPP	127,900	109,597	84,796	58,683	49,685	38,428	36,315	35,338	34,608	34,115	34,401
EPA Reg + MSD	127,900	109,598	84,014	58,498	49,551	39,080	36,438	35,648	35,205	34,979	35,173
EPA Reg + MSD/MAPP	127,900	109,598	84,014	58,498	49,551	39,080	36,438	35,648	35,275	35,024	35,183
Low Load + PJM EE	127,900	108,420	82,534	56,398	47,128	37,646	34,489	33,319	32,076	31,392	31,310
Med Renew + MSD	127,900	109,600	84,789	58,738	49,736	39,563	36,886	35,965	35,521	35,403	35,610
High Renew + EE/MSD	127,900	109,606	84,289	58,098	48,985	38,770	35,650	34,208	32,929	31,965	31,984
Life Xtsn + MSD	127,900	109,231	84,788	57,190	48,524	39,507	37,066	36,089	35,755	35,689	36,154

*The analogous projections for the Supplemental Responsive Scenarios) are included in Appendix L.

Table 14.7 (cont.) Annual SO_2 Emissions from Electricity Consumption in Maryland (tons)*

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reference Case	36,272	36,054	36,180	36,546	35,871	35,455	34,999	34,842	33,455	33,738
MSD	36,272	36,048	36,249	36,501	35,857	35,425	35,022	35,141	33,550	33,781
MAPP	36,286	36,054	36,171	36,518	35,836	35,422	34,986	34,828	33,453	33,721
CC3	35,876	36,003	36,102	36,429	35,755	35,310	34,870	34,941	33,496	33,741
MSD + MAPP	36,272	36,059	36,156	36,518	35,856	35,434	35,006	34,882	33,499	33,741
CC3 + NCO2	34,271	34,499	34,718	35,165	34,781	34,784	34,402	34,579	33,442	33,488
CC3/NCO2/MSD/MAPP	34,393	34,561	34,853	35,298	34,791	34,675	34,247	34,650	33,380	33,399
NCO2	34,736	34,642	34,825	35,288	34,886	34,840	34,511	34,846	33,513	33,483
NCO2 + MSD	34,735	34,700	34,853	35,289	34,914	34,989	34,446	34,858	33,458	33,443
High Gas	36,690	36,506	36,624	36,989	36,318	35,871	35,147	35,266	33,963	34,637
High Gas + MSD	36,693	36,485	36,628	36,969	36,309	35,855	35,108	35,176	33,833	34,499
Low Gas	35,695	35,435	35,532	35,870	35,020	34,887	33,794	33,612	32,809	33,014
Low Gas + MSD	35,697	35,403	35,473	35,837	35,001	34,811	33,845	33,657	32,827	33,089
High Load	38,542	38,640	38,900	39,453	39,051	38,644	37,737	37,532	35,552	35,112
High Load + MSD	38,306	38,348	38,893	39,388	38,910	38,594	37,739	37,522	35,506	35,112
High Load + CC3/NCO2/MSD/MAPP	36,981	37,138	37,368	38,199	37,737	37,911	37,272	37,446	35,568	34,905
Low Load	32,615	32,132	32,241	32,580	32,356	32,245	32,157	31,947	30,431	30,893
Low Load + MSD	32,608	32,130	32,236	32,571	32,340	32,375	32,239	31,970	30,451	30,896
Low Load + CC3/NCO2/MSD/MAPP	31,101	30,810	30,874	31,270	31,167	31,587	31,666	32,066	31,183	31,944
High Renew	35,682	35,446	35,175	35,092	33,975	33,189	32,047	31,771	30,120	30,025
High Renew + MSD	35,681	35,442	35,191	35,091	33,984	33,169	32,349	32,033	30,216	30,067
High Renew + CC3/NCO2	33,710	33,596	33,678	33,700	32,818	32,514	31,717	31,805	30,224	29,905
High Renew + CC3/NCO2/MSD/MAPP	33,823	33,749	33,758	33,777	32,913	32,484	31,661	31,742	30,148	29,808
EE	32,965	33,079	33,237	33,593	32,965	32,639	31,986	32,070	30,876	31,173
EE + MSD	32,961	33,071	33,218	33,560	32,924	32,533	32,194	32,072	30,797	31,147
EE + CC3/NCO2	30,865	31,143	31,653	32,142	31,873	31,961	31,665	32,058	30,887	30,834
EE + CC3/NCO2/MSD/MAPP	31,021	31,569	31,804	32,286	31,959	32,043	31,877	32,162	30,862	30,833
Climate Change	36,375	36,023	36,187	36,928	36,407	36,017	35,262	34,948	33,536	33,666
Climate Change + CC3/NCO2/MSD/MAPP	34,858	34,676	34,858	35,384	34,821	34,979	34,479	34,881	33,480	33,234
EPA Reg + MSD	35,497	35,307	35,374	35,759	35,054	34,947	34,292	34,336	32,701	32,834
EPA Reg + MSD/MAPP	35,493	35,294	35,358	35,753	35,048	34,887	34,212	34,255	32,690	32,794
Low Load + PJM EE	31,480	30,719	30,634	31,063	30,420	30,129	29,556	29,389	28,479	29,223
Med Renew + MSD	36,013	35,854	35,764	35,883	35,000	34,359	33,792	33,650	31,960	32,021
High Renew + EE/MSD	32,390	32,517	32,269	32,247	31,232	30,579	29,551	29,277	27,856	27,771
Life Xtsn + MSD	36,511	36,350	36,491	36,772	36,121	35,802	35,329	35,385	33,957	33,988

*The analogous projections for the Supplemental Responsive Scenarios) are included in Appendix L.

Table 14.7 (cont.) Annual SO_2 Emissions from Electricity Consumption in Maryland (tons)*

	2010-2020 Average Annual Emissions	2021-2030 Average Annual Emissions	2010-2030 Average Annual Emissions	2010-2030 Cumulative Emissions
Reference Case	59,068	35,341	47,770	1,003,200
MSD	59,074	35,385	47,793	1,003,700
MAPP	59,081	35,327	47,770	1,003,200
CC3	58,978	35,252	47,680	1,001,300
MSD + MAPP	59,059	35,342	47,765	1,003,100
CC3 + NCO2	58,217	34,413	46,882	984,500
CC3/NCO2/MSD/MAPP	58,263	34,425	46,912	985,100
NCO2	58,278	34,557	46,982	986,600
NCO2 + MSD	58,310	34,568	47,004	987,100
High Gas	60,139	35,801	48,550	1,019,500
High Gas + MSD	60,134	35,755	48,525	1,019,000
Low Gas	55,951	34,567	45,768	961,100
Low Gas + MSD	55,929	34,564	45,755	960,900
High Load	60,704	37,916	49,853	1,046,900
High Load + MSD	60,704	37,832	49,812	1,046,100
High Load + CC3/NCO2/MSD/MAPP	59,918	37,052	49,030	1,029,600
Low Load	57,438	31,960	45,306	951,400
Low Load + MSD	57,438	31,982	45,316	951,600
Low Load + CC3/NCO2/MSD/MAPP	56,683	31,367	44,628	937,200
High Renew	59,018	33,252	46,748	981,700
High Renew + MSD	59,022	33,322	46,784	982,500
High Renew + CC3/NCO2	58,124	32,367	45,859	963,000
High Renew + CC3/NCO2/MSD/MAPP	58,235	32,386	45,926	964,400
EE	57,765	32,458	45,714	960,000
EE + MSD	57,768	32,448	45,711	959,900
EE + CC3/NCO2	56,885	31,508	44,801	940,800
EE + CC3/NCO2/MSD/MAPP	56,938	31,642	44,892	942,700
Climate Change	59,324	35,535	47,996	1,007,900
Climate Change + CC3/NCO2/MSD/MAPP	58,533	34,565	47,120	989,500
EPA Reg + MSD	58,735	34,610	47,247	992,200
EPA Reg + MSD/MAPP	58,746	34,578	47,238	992,000
Low Load + PJM EE	56,601	30,109	43,986	923,700
Med Renew + MSD	59,065	34,430	47,334	994,000
High Renew + EE/MSD	57,671	30,569	44,765	940,100
Life Xtsn + MSD	58,899	35,671	47,838	1,004,600

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Table 14.8 Annual NO_x Emissions from Electricity Consumption in Maryland (tons)*

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Reference Case	40,494	37,907	34,629	30,112	28,951	28,979	27,952	27,887	27,587	27,352	27,635
MSD	40,494	37,907	34,628	30,111	28,951	28,983	27,953	27,882	27,587	27,346	27,628
MAPP	40,494	37,907	34,628	30,111	28,951	28,979	27,952	27,887	27,613	27,376	27,648
CC3	40,494	37,907	34,629	30,112	28,951	28,979	27,952	27,887	27,587	27,188	27,394
MSD + MAPP	40,494	37,907	34,628	30,111	28,951	28,983	27,953	27,882	27,614	27,372	27,577
CC3 + NCO2	40,494	37,907	34,633	30,093	28,934	28,210	27,153	26,731	26,258	25,819	25,998
CC3/NCO2/MSD/MAPP	40,494	37,907	34,633	30,093	28,934	28,225	27,196	26,743	26,225	25,843	26,010
NCO2	40,494	37,907	34,633	30,093	28,934	28,210	27,153	26,731	26,258	26,001	26,303
NCO2 + MSD	40,494	37,907	34,633	30,093	28,934	28,225	27,196	26,743	26,182	25,966	26,210
High Gas	41,257	38,308	35,220	30,572	29,263	29,099	28,035	28,001	27,619	27,518	27,731
High Gas + MSD	41,257	38,308	35,220	30,572	29,263	29,099	28,039	28,000	27,600	27,498	27,707
Low Gas	38,565	36,294	33,073	28,874	28,071	28,461	27,631	27,727	27,393	27,185	27,581
Low Gas + MSD	38,565	36,294	33,073	28,874	28,071	28,464	27,634	27,726	27,389	27,151	27,531
High Load	40,494	38,140	35,059	30,677	29,699	29,921	29,041	29,132	28,609	28,343	28,532
High Load + MSD	40,494	38,140	35,059	30,677	29,699	29,923	29,039	29,127	28,580	28,358	28,514
High Load + CC3/NCO2/MSD/MAPP	40,494	38,140	35,072	30,640	29,661	29,064	28,270	28,217	27,762	27,479	27,689
Low Load	40,494	37,660	34,141	29,494	28,229	28,233	27,145	26,915	26,277	25,769	25,926
Low Load + MSD	40,494	37,660	34,141	29,494	28,229	28,232	27,144	26,914	26,276	25,773	25,924
Low Load + CC3/NCO2/MSD/MAPP	40,494	37,660	34,144	29,475	28,224	27,419	26,246	25,229	24,558	23,900	23,736
High Renew	40,494	37,907	34,628	30,111	28,951	28,979	27,952	27,887	27,590	27,265	27,432
High Renew + MSD	40,494	37,907	34,628	30,111	28,951	28,983	27,953	27,882	27,589	27,260	27,428
High Renew + CC3/NCO2	40,494	37,907	34,633	30,093	28,934	28,210	27,153	26,731	26,147	25,695	25,842
High Renew + CC3/NCO2/MSD/MAPP	40,494	37,907	34,633	30,093	28,934	28,225	27,196	26,743	26,225	25,766	25,844
EE	40,494	37,906	34,425	29,774	28,498	28,400	27,001	26,542	25,782	25,271	25,198
EE + MSD	40,494	37,906	34,425	29,774	28,498	28,403	27,002	26,541	25,783	25,268	25,195
EE + CC3/NCO2	40,494	37,906	34,430	29,761	28,484	27,649	26,224	25,412	24,386	23,382	23,183
EE + CC3/NCO2/MSD/MAPP	40,494	37,906	34,430	29,761	28,484	27,668	26,263	25,419	24,466	23,518	23,350
Climate Change	40,494	37,907	34,628	30,111	28,946	29,066	28,160	28,052	27,608	27,370	27,544
Climate Change + CC3/NCO2/MSD/MAPP	40,494	37,907	34,632	30,094	28,930	28,318	27,347	27,104	26,594	26,172	26,292
EPA Reg + MSD	40,494	37,910	34,391	30,058	28,913	25,257	24,306	24,168	23,614	23,418	23,623
EPA Reg + MSD/MAPP	40,494	37,910	34,391	30,058	28,913	25,257	24,306	24,168	23,642	23,448	23,631
Low Load + PJM EE	40,494	37,465	33,801	29,052	27,707	27,717	26,416	26,054	25,325	24,881	24,967
Med Renew + MSD	40,494	37,903	34,630	30,111	28,950	28,979	27,959	27,918	27,624	27,342	27,552
High Renew + EE/MSD	40,494	37,906	34,425	29,774	28,498	28,400	27,001	26,542	25,783	25,081	25,019
Life Xtsn + MSD	40,494	37,907	34,627	30,150	29,147	29,245	28,249	28,231	27,928	27,693	28,035

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Table 14.8 (cont.) Annual NO_x Emissions from Electricity Consumption in Maryland (tons)*

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reference Case	27,704	27,511	27,708	27,914	27,822	27,819	27,597	27,029	26,055	25,757
MSD	27,714	27,509	27,735	27,890	27,822	27,792	27,602	27,058	26,079	25,775
MAPP	27,699	27,511	27,678	27,884	27,821	27,787	27,582	27,021	26,069	25,759
CC3	27,528	27,419	27,601	27,793	27,739	27,670	27,453	26,933	25,986	25,676
MSD + MAPP	27,716	27,511	27,668	27,883	27,830	27,782	27,575	27,044	26,082	25,780
CC3 + NCO2	26,211	26,184	26,435	26,714	26,679	26,946	26,848	26,509	25,997	25,611
CC3/NCO2/MSD/MAPP	26,185	26,150	26,359	26,636	26,598	26,802	26,648	26,410	25,807	25,392
NCO2	26,518	26,340	26,572	26,835	26,823	27,059	27,004	26,682	26,071	25,645
NCO2 + MSD	26,416	26,274	26,480	26,735	26,704	27,014	26,875	26,562	25,889	25,474
High Gas	27,764	27,576	27,716	27,949	27,861	27,854	27,531	27,026	26,165	25,890
High Gas + MSD	27,734	27,581	27,727	27,942	27,844	27,845	27,516	26,989	26,102	25,831
Low Gas	27,652	27,435	27,618	27,846	27,718	27,874	27,472	26,931	26,297	26,014
Low Gas + MSD	27,678	27,432	27,609	27,822	27,669	27,779	27,431	26,916	26,314	26,058
High Load	28,803	28,807	29,047	29,381	29,352	29,343	29,026	28,424	27,360	26,866
High Load + MSD	28,724	28,721	29,064	29,336	29,323	29,343	29,035	28,403	27,319	26,846
High Load + CC3/NCO2/MSD/MAPP	27,856	27,925	28,238	28,629	28,618	28,919	28,798	28,477	27,563	26,977
Low Load	25,977	25,710	25,891	26,112	26,144	26,165	25,934	25,328	24,444	24,173
Low Load + MSD	25,973	25,711	25,890	26,107	26,134	26,148	25,953	25,332	24,440	24,133
Low Load + CC3/NCO2/MSD/MAPP	23,765	23,627	23,790	24,015	24,103	24,399	24,357	24,096	23,505	23,387
High Renew	27,245	27,018	26,888	26,751	26,328	25,974	25,300	24,601	23,415	22,859
High Renew + MSD	27,240	27,029	26,908	26,764	26,341	25,972	25,439	24,650	23,459	22,894
High Renew + CC3/NCO2	25,764	25,649	25,653	25,588	25,227	25,182	24,753	24,243	23,400	22,767
High Renew + CC3/NCO2/MSD/MAPP	25,743	25,638	25,597	25,541	25,164	25,075	24,623	24,110	23,251	22,603
EE	25,304	25,205	25,410	25,631	25,574	25,550	25,263	24,834	24,009	23,754
EE + MSD	25,317	25,210	25,414	25,620	25,525	25,529	25,378	24,860	23,997	23,734
EE + CC3/NCO2	23,530	23,522	23,841	24,151	24,166	24,408	24,352	24,111	23,491	23,080
EE + CC3/NCO2/MSD/MAPP	23,641	23,696	23,914	24,210	24,191	24,446	24,443	24,150	23,461	23,058
Climate Change	27,632	27,421	27,612	27,993	27,961	27,980	27,645	26,950	25,977	25,617
Climate Change + CC3/NCO2/MSD/MAPP	26,517	26,356	26,541	26,841	26,770	27,121	27,009	26,700	26,020	25,576
EPA Reg + MSD	23,700	23,549	23,647	23,873	23,819	23,892	23,609	22,985	21,937	21,540
EPA Reg + MSD/MAPP	23,696	23,534	23,635	23,862	23,806	23,891	23,589	22,965	21,918	21,528
Low Load + PJM EE	25,032	24,632	24,685	24,953	24,831	24,837	24,547	24,061	23,411	23,199
Med Renew + MSD	27,520	27,331	27,357	27,381	27,137	26,914	26,580	25,920	24,836	24,399
High Renew + EE/MSD	24,866	24,762	24,655	24,570	24,176	23,910	23,313	22,632	21,602	21,113
Life Xtsn + MSD	28,141	27,948	28,151	28,361	28,255	28,321	28,117	27,729	26,911	27,142

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Table 14.8 (cont.) Annual NO_x Emissions from Electricity Consumption in Maryland (tons)*

	2010-2020 Average Annual Emissions	2021-2030 Average Annual Emissions	2010-2030 Average Annual Emissions	2010-2030 Cumulative Emissions
Reference Case	30,862	27,292	29,162	612,400
MSD	30,861	27,297	29,164	612,400
MAPP	30,868	27,281	29,160	612,400
CC3	30,825	27,180	29,089	610,900
MSD + MAPP	30,861	27,287	29,159	612,300
CC3 + NCO2	30,203	26,414	28,398	596,400
CC3/NCO2/MSD/MAPP	30,209	26,299	28,347	595,300
NCO2	30,247	26,555	28,489	598,300
NCO2 + MSD	30,235	26,442	28,429	597,000
High Gas	31,148	27,333	29,331	616,000
High Gas + MSD	31,142	27,311	29,318	615,700
Low Gas	30,078	27,286	28,748	603,700
Low Gas + MSD	30,070	27,271	28,737	603,500
High Load	31,604	28,641	30,193	634,100
High Load + MSD	31,601	28,612	30,177	633,700
High Load + CC3/NCO2/MSD/MAPP	31,135	28,200	29,737	624,500
Low Load	30,026	25,588	27,912	586,200
Low Load + MSD	30,026	25,582	27,910	586,100
Low Load + CC3/NCO2/MSD/MAPP	29,190	23,904	26,673	560,100
High Renew	30,836	25,638	28,361	595,600
High Renew + MSD	30,835	25,670	28,375	595,900
High Renew + CC3/NCO2	30,167	24,823	27,622	580,100
High Renew + CC3/NCO2/MSD/MAPP	30,187	24,735	27,591	579,400
EE	29,936	25,053	27,611	579,800
EE + MSD	29,935	25,058	27,613	579,900
EE + CC3/NCO2	29,210	23,865	26,665	560,000
EE + CC3/NCO2/MSD/MAPP	29,251	23,921	26,713	561,000
Climate Change	30,899	27,279	29,175	612,700
Climate Change + CC3/NCO2/MSD/MAPP	30,353	26,545	28,540	599,300
EPA Reg + MSD	28,741	23,255	26,129	548,700
EPA Reg + MSD/MAPP	28,747	23,242	26,126	548,600
Low Load + PJM EE	29,443	24,419	27,051	568,100
Med Renew + MSD	30,860	26,537	28,802	604,800
High Renew + EE/MSD	29,902	23,560	26,882	564,500
Life Xtsn + MSD	31,064	27,908	29,561	620,800

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Table 14.9 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	43,735	42,678	41,811	40,609	39,418	39,468	38,819	39,069	38,611	38,410	38,893
MSD	43,735	42,678	41,811	40,609	39,418	39,470	38,818	39,066	38,612	38,406	38,888
MAPP	43,735	42,678	41,811	40,609	39,418	39,468	38,819	39,069	38,636	38,437	38,915
CC3	43,735	42,678	41,811	40,609	39,418	39,468	38,819	39,069	38,611	38,216	38,495
MSD + MAPP	43,735	42,678	41,811	40,609	39,418	39,470	38,818	39,066	38,641	38,437	38,846
CC3 + NCO2	43,735	42,679	41,817	40,590	39,400	38,705	37,920	37,822	37,186	36,697	37,090
CC3/NCO2/MSD/MAPP	43,735	42,679	41,817	40,590	39,400	38,716	37,951	37,826	37,173	36,745	37,134
NCO2	43,735	42,679	41,817	40,590	39,400	38,705	37,920	37,822	37,186	36,912	37,496
NCO2 + MSD	43,735	42,679	41,817	40,590	39,400	38,716	37,951	37,826	37,141	36,956	37,443
High Gas	44,234	42,989	42,367	41,128	39,740	39,545	38,792	39,093	38,491	38,448	38,880
High Gas + MSD	44,234	42,989	42,367	41,128	39,740	39,544	38,792	39,093	38,475	38,434	38,858
Low Gas	42,346	41,380	40,643	39,671	38,773	39,164	38,494	38,843	38,399	38,192	38,817
Low Gas + MSD	42,346	41,380	40,643	39,671	38,773	39,164	38,496	38,844	38,396	38,139	38,774
High Load	43,735	42,908	42,257	41,215	40,221	40,588	40,184	40,726	40,225	40,307	40,794
High Load + MSD	43,735	42,908	42,257	41,215	40,221	40,588	40,180	40,723	40,239	40,281	40,774
High Load + CC3/NCO2/MSD/MAPP	43,735	42,908	42,265	41,161	40,170	39,803	39,298	39,573	39,192	38,981	39,577
Low Load	43,735	42,432	41,325	39,952	38,613	38,684	37,839	37,941	37,019	36,398	36,695
Low Load + MSD	43,735	42,432	41,325	39,952	38,613	38,682	37,835	37,941	37,020	36,405	36,693
Low Load + CC3/NCO2/MSD/MAPP	43,735	42,432	41,327	39,929	38,611	37,798	36,814	36,172	35,383	34,627	34,651
High Renew	43,735	42,678	41,811	40,609	39,418	39,468	38,819	39,069	38,613	38,290	38,573
High Renew + MSD	43,735	42,678	41,811	40,609	39,418	39,470	38,818	39,066	38,615	38,285	38,570
High Renew + CC3/NCO2	43,735	42,679	41,817	40,590	39,400	38,705	37,920	37,822	37,109	36,539	36,833
High Renew + CC3/NCO2/MSD/MAPP	43,735	42,679	41,817	40,590	39,400	38,716	37,951	37,826	37,173	36,633	36,898
EE	43,735	42,677	41,568	40,163	38,804	38,689	37,505	37,203	36,152	35,512	35,400
EE + MSD	43,735	42,677	41,568	40,163	38,804	38,689	37,505	37,205	36,154	35,509	35,400
EE + CC3/NCO2	43,735	42,677	41,572	40,147	38,786	37,944	36,633	35,970	34,717	33,649	33,488
EE + CC3/NCO2/MSD/MAPP	43,735	42,677	41,572	40,147	38,786	37,957	36,661	35,972	34,775	33,768	33,627
Climate Change	43,735	42,679	41,811	40,609	39,412	39,604	39,027	39,212	38,667	38,560	38,920
Climate Change + CC3/NCO2/MSD/MAPP	43,735	42,678	41,817	40,590	39,392	38,854	38,090	38,061	37,444	37,117	37,427
EPA Reg + MSD	43,735	42,671	41,581	40,522	39,372	39,310	38,700	38,846	38,195	38,125	38,689
EPA Reg + MSD/MAPP	43,735	42,671	41,581	40,522	39,372	39,310	38,700	38,846	38,226	38,120	38,725
Low Load + PJM EE	43,735	42,238	40,984	39,463	38,023	38,081	37,030	36,972	36,032	35,541	35,671
Med Renew + MSD	43,735	42,674	41,814	40,613	39,419	39,470	38,824	39,123	38,667	38,406	38,752
High Renew + EE/MSD	43,735	42,677	41,568	40,163	38,804	38,689	37,505	37,203	36,154	35,326	35,151
Life Xtsn + MSD	43,735	42,679	41,811	40,619	39,504	39,610	38,981	39,263	38,812	38,611	39,106

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Table 14.9 (cont.) Annual CO_2 Emissions from Electricity Consumption in Maryland (thousands of tons)*

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reference Case	39,154	39,107	39,673	40,207	40,283	40,673	40,928	40,982	41,174	41,060
MSD	39,158	39,137	39,690	40,191	40,332	40,644	40,890	40,964	41,151	41,018
MAPP	39,219	39,179	39,760	40,270	40,373	40,686	40,956	41,030	41,239	41,100
CC3	38,715	38,803	39,333	39,818	39,943	40,301	40,505	40,629	40,854	40,707
MSD + MAPP	39,188	39,222	39,740	40,205	40,381	40,685	40,958	41,016	41,203	41,063
CC3 + NCO2	37,369	37,461	38,055	38,643	38,841	37,696	37,685	35,943	34,712	32,932
CC3/NCO2/MSD/MAPP	37,378	37,465	38,076	38,672	38,798	37,658	37,625	35,938	34,666	32,858
NCO2	37,835	37,832	38,478	39,099	39,254	38,008	38,006	36,227	34,997	33,171
NCO2 + MSD	37,782	37,892	38,428	39,044	39,195	37,456	37,922	36,127	34,834	33,054
High Gas	39,089	39,142	39,668	40,108	40,190	40,573	40,795	40,836	41,055	40,923
High Gas + MSD	39,138	39,140	39,626	40,122	40,201	40,538	40,781	40,818	41,028	40,881
Low Gas	39,080	39,021	39,508	40,077	40,089	40,636	40,765	40,837	41,309	41,163
Low Gas + MSD	39,115	39,069	39,470	40,087	40,115	40,676	40,827	40,878	41,286	41,163
High Load	41,321	41,584	42,214	43,012	43,373	43,824	44,189	44,232	44,487	44,367
High Load + MSD	41,269	41,523	42,228	42,935	43,290	43,742	44,070	44,103	44,357	44,242
High Load + CC3/NCO2/MSD/MAPP	40,036	40,296	41,030	41,844	42,310	40,600	40,914	39,228	37,728	36,180
Low Load	36,758	36,457	36,762	37,039	37,135	37,310	37,437	37,309	37,380	37,252
Low Load + MSD	36,756	36,458	36,760	37,032	37,124	37,240	37,443	37,304	37,368	37,256
Low Load + CC3/NCO2/MSD/MAPP	34,658	34,451	34,733	35,056	35,196	34,087	33,692	32,336	31,963	29,163
High Renew	38,445	38,401	38,483	38,467	38,060	37,907	37,596	37,208	36,862	36,272
High Renew + MSD	38,444	38,411	38,457	38,435	38,029	37,879	37,577	37,184	36,812	36,217
High Renew + CC3/NCO2	36,704	36,648	36,861	36,954	36,666	35,113	34,673	32,713	31,150	29,099
High Renew + CC3/NCO2/MSD/MAPP	36,714	36,675	36,848	36,950	36,627	35,112	34,628	32,665	31,042	29,022
EE	35,633	35,735	36,285	36,751	36,910	37,241	37,478	37,547	37,796	37,699
EE + MSD	35,647	35,730	36,222	36,709	36,820	37,218	37,489	37,575	37,745	37,664
EE + CC3/NCO2	33,849	33,912	34,595	35,163	35,382	34,317	34,344	32,895	31,539	29,873
EE + CC3/NCO2/MSD/MAPP	33,938	34,074	34,627	35,235	35,420	33,904	34,396	32,982	31,552	29,875
Climate Change	39,283	39,283	39,771	40,433	40,624	40,975	41,140	41,091	41,248	41,081
Climate Change + CC3/NCO2/MSD/MAPP	37,705	37,728	38,333	39,085	39,324	37,630	38,058	36,007	34,869	33,054
EPA Reg + MSD	38,967	38,970	39,477	40,062	40,162	40,604	40,831	40,937	40,952	40,809
EPA Reg + MSD/MAPP	39,011	39,008	39,506	40,090	40,192	40,666	40,887	40,972	40,994	40,870
Low Load + PJM EE	35,764	35,196	35,270	35,657	35,528	35,695	35,680	35,573	35,694	35,586
Med Renew + MSD	38,829	38,880	39,085	39,345	39,233	39,291	39,307	39,139	39,061	38,723
High Renew + EE/MSD	34,992	35,059	35,156	35,161	34,824	34,729	34,469	34,134	33,816	33,293
Life Xtsn + MSD	39,347	39,345	39,918	40,408	40,459	40,855	41,126	41,235	41,497	42,065

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Table 14.9 (cont.) Annual CO_2 Emissions from Electricity Consumption in Maryland (thousands of tons)*

	2010-2020 Average Annual Emissions	2021-2030 Average Annual Emissions	2010-2030 Average Annual Emissions	2010-2030 Cumulative Emissions
Reference Case	40,138	40,324	40,227	844,800
MSD	40,137	40,318	40,223	844,700
MAPP	40,145	40,381	40,258	845,400
CC3	40,085	39,961	40,026	840,500
MSD + MAPP	40,139	40,366	40,247	845,200
CC3 + NCO2	39,422	36,934	38,237	803,000
CC3/NCO2/MSD/MAPP	39,433	36,913	38,233	802,900
NCO2	39,478	37,291	38,437	807,200
NCO2 + MSD	39,478	37,173	38,380	806,000
High Gas	40,337	40,238	40,290	846,100
High Gas + MSD	40,332	40,227	40,282	845,900
Low Gas	39,520	40,248	39,867	837,200
Low Gas + MSD	39,511	40,269	39,872	837,300
High Load	41,196	43,260	42,179	885,800
High Load + MSD	41,193	43,176	42,137	884,900
High Load + CC3/NCO2/MSD/MAPP	40,606	40,017	40,325	846,800
Low Load	39,148	37,084	38,165	801,500
Low Load + MSD	39,148	37,074	38,161	801,400
Low Load + CC3/NCO2/MSD/MAPP	38,316	33,533	36,039	756,800
High Renew	40,099	37,770	38,990	818,800
High Renew + MSD	40,098	37,745	38,977	818,500
High Renew + CC3/NCO2	39,377	34,658	37,130	779,700
High Renew + CC3/NCO2/MSD/MAPP	39,402	34,628	37,129	779,700
EE	38,855	36,908	37,928	796,500
EE + MSD	38,855	36,882	37,916	796,200
EE + CC3/NCO2	38,120	33,587	35,961	755,200
EE + CC3/NCO2/MSD/MAPP	38,153	33,600	35,985	755,700
Climate Change	40,203	40,493	40,341	847,200
Climate Change + CC3/NCO2/MSD/MAPP	39,564	37,179	38,428	807,000
EPA Reg + MSD	39,977	40,177	40,072	841,500
EPA Reg + MSD/MAPP	39,982	40,220	40,095	842,000
Low Load + PJM EE	38,525	35,564	37,115	779,400
Med Renew + MSD	40,136	39,089	39,638	832,400
High Renew + EE/MSD	38,816	34,563	36,791	772,600
Life Xtsn + MSD	40,248	40,626	40,428	849,000

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Table 14.10 Annual Mercury Emissions from Electricity Consumption in Maryland (pounds)*

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Reference Case	2,511	2,431	2,328	2,240	2,164	2,163	2,132	2,144	2,122	2,119	2,132
MSD	2,511	2,432	2,328	2,241	2,165	2,163	2,132	2,144	2,124	2,120	2,132
MAPP	2,511	2,432	2,328	2,241	2,165	2,162	2,132	2,144	2,124	2,121	2,133
CC3	2,511	2,431	2,328	2,240	2,164	2,163	2,132	2,144	2,122	2,110	2,130
MSD + MAPP	2,511	2,432	2,328	2,241	2,165	2,163	2,132	2,144	2,125	2,121	2,131
CC3 + NCO2	2,511	2,432	2,329	2,239	2,163	2,094	2,066	2,053	2,025	2,007	2,041
CC3/NCO2/MSD/MAPP	2,511	2,432	2,329	2,239	2,163	2,095	2,067	2,053	2,015	2,000	2,032
NCO2	2,511	2,432	2,329	2,239	2,163	2,094	2,066	2,053	2,025	2,013	2,044
NCO2 + MSD	2,511	2,432	2,329	2,239	2,163	2,095	2,067	2,053	2,014	2,002	2,032
High Gas	2,538	2,448	2,378	2,291	2,193	2,180	2,138	2,155	2,124	2,128	2,144
High Gas + MSD	2,538	2,448	2,378	2,291	2,193	2,181	2,139	2,155	2,124	2,128	2,143
Low Gas	2,435	2,365	2,242	2,172	2,116	2,137	2,094	2,115	2,095	2,078	2,116
Low Gas + MSD	2,435	2,365	2,242	2,172	2,116	2,137	2,095	2,115	2,095	2,072	2,114
High Load	2,511	2,441	2,347	2,265	2,193	2,223	2,202	2,226	2,182	2,177	2,192
High Load + MSD	2,511	2,441	2,347	2,265	2,193	2,223	2,202	2,227	2,181	2,176	2,191
High Load + CC3/NCO2/MSD/MAPP	2,511	2,441	2,348	2,259	2,188	2,158	2,147	2,151	2,113	2,105	2,143
Low Load	2,511	2,421	2,306	2,211	2,132	2,143	2,098	2,104	2,047	2,000	2,022
Low Load + MSD	2,511	2,421	2,306	2,211	2,132	2,143	2,099	2,104	2,047	2,001	2,022
Low Load + CC3/NCO2/MSD/MAPP	2,511	2,421	2,306	2,209	2,132	2,056	2,010	1,960	1,913	1,866	1,884
High Renew	2,511	2,432	2,328	2,241	2,165	2,162	2,132	2,144	2,123	2,113	2,119
High Renew + MSD	2,511	2,432	2,328	2,241	2,165	2,163	2,132	2,144	2,124	2,114	2,119
High Renew + CC3/NCO2	2,511	2,432	2,329	2,239	2,163	2,094	2,066	2,053	2,007	1,994	2,028
High Renew + CC3/NCO2/MSD/MAPP	2,511	2,432	2,329	2,239	2,163	2,095	2,067	2,053	2,015	1,994	2,019
EE	2,511	2,432	2,315	2,217	2,132	2,121	2,062	2,045	1,987	1,960	1,952
EE + MSD	2,511	2,432	2,315	2,217	2,132	2,121	2,062	2,046	1,987	1,960	1,952
EE + CC3/NCO2	2,511	2,432	2,316	2,215	2,131	2,055	1,999	1,951	1,877	1,820	1,827
EE + CC3/NCO2/MSD/MAPP	2,511	2,432	2,316	2,215	2,131	2,056	1,999	1,950	1,880	1,824	1,828
Climate Change	2,511	2,432	2,328	2,241	2,164	2,184	2,162	2,177	2,133	2,119	2,133
Climate Change + CC3/NCO2/MSD/MAPP	2,511	2,432	2,329	2,239	2,163	2,119	2,098	2,092	2,047	2,032	2,050
EPA Reg + MSD	2,511	2,432	2,303	2,232	2,158	2,149	2,135	2,143	2,103	2,086	2,103
EPA Reg + MSD/MAPP	2,511	2,432	2,303	2,232	2,158	2,149	2,135	2,143	2,104	2,086	2,103
Low Load + PJM EE	2,511	2,415	2,293	2,192	2,110	2,122	2,060	2,067	2,013	1,978	1,987
Med Renew + MSD	2,511	2,431	2,329	2,241	2,165	2,163	2,132	2,150	2,129	2,123	2,131
High Renew + EE/MSD	2,511	2,432	2,315	2,217	2,132	2,121	2,062	2,045	1,987	1,940	1,933
Life Xtsn + MSD	2,511	2,432	2,328	2,241	2,173	2,173	2,146	2,160	2,137	2,134	2,148

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Table 14.10 (cont.) Annual Mercury Emissions from Electricity Consumption in Maryland (pounds)*

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reference Case	2,144	2,137	2,156	2,167	2,156	2,165	2,168	2,145	2,093	2,043
MSD	2,144	2,138	2,157	2,167	2,157	2,166	2,170	2,148	2,094	2,044
MAPP	2,144	2,138	2,154	2,167	2,156	2,165	2,168	2,145	2,094	2,043
CC3	2,143	2,138	2,154	2,166	2,155	2,164	2,167	2,146	2,094	2,043
MSD + MAPP	2,144	2,139	2,155	2,167	2,157	2,166	2,168	2,146	2,094	2,044
CC3 + NCO2	2,053	2,054	2,074	2,093	2,093	2,113	2,121	2,114	2,089	2,028
CC3/NCO2/MSD/MAPP	2,043	2,037	2,067	2,086	2,076	2,094	2,103	2,103	2,070	2,008
NCO2	2,056	2,056	2,074	2,095	2,094	2,112	2,123	2,124	2,091	2,029
NCO2 + MSD	2,043	2,044	2,062	2,082	2,081	2,100	2,107	2,109	2,072	2,009
High Gas	2,150	2,143	2,160	2,173	2,160	2,168	2,163	2,144	2,097	2,046
High Gas + MSD	2,150	2,143	2,161	2,173	2,160	2,168	2,162	2,144	2,095	2,045
Low Gas	2,128	2,118	2,134	2,147	2,124	2,151	2,136	2,114	2,093	2,044
Low Gas + MSD	2,129	2,118	2,131	2,147	2,123	2,150	2,140	2,117	2,094	2,045
High Load	2,210	2,210	2,229	2,245	2,240	2,237	2,228	2,197	2,136	2,068
High Load + MSD	2,208	2,207	2,229	2,243	2,238	2,237	2,228	2,196	2,135	2,067
High Load + CC3/NCO2/MSD/MAPP	2,157	2,158	2,181	2,208	2,203	2,215	2,219	2,206	2,149	2,076
Low Load	2,021	2,010	2,033	2,043	2,048	2,051	2,060	2,033	1,997	1,963
Low Load + MSD	2,021	2,010	2,033	2,042	2,047	2,057	2,062	2,034	1,998	1,967
Low Load + CC3/NCO2/MSD/MAPP	1,882	1,872	1,891	1,902	1,925	1,951	1,958	1,965	1,958	1,935
High Renew	2,110	2,102	2,096	2,080	2,043	2,029	1,996	1,958	1,886	1,820
High Renew + MSD	2,110	2,101	2,096	2,081	2,043	2,029	2,005	1,962	1,888	1,821
High Renew + CC3/NCO2	2,020	2,017	2,016	2,011	1,981	1,977	1,958	1,941	1,888	1,812
High Renew + CC3/NCO2/MSD/MAPP	2,010	2,007	2,005	1,998	1,969	1,962	1,944	1,926	1,870	1,793
EE	1,964	1,962	1,980	1,993	1,984	1,995	1,991	1,976	1,933	1,888
EE + MSD	1,964	1,962	1,980	1,992	1,984	1,994	1,999	1,979	1,932	1,888
EE + CC3/NCO2	1,856	1,864	1,885	1,907	1,909	1,929	1,937	1,940	1,907	1,849
EE + CC3/NCO2/MSD/MAPP	1,857	1,866	1,885	1,906	1,907	1,926	1,941	1,940	1,904	1,847
Climate Change	2,145	2,135	2,152	2,170	2,164	2,166	2,160	2,126	2,074	2,017
Climate Change + CC3/NCO2/MSD/MAPP	2,064	2,057	2,080	2,094	2,089	2,107	2,113	2,114	2,075	2,009
EPA Reg + MSD	2,106	2,097	2,114	2,131	2,117	2,141	2,139	2,119	2,065	2,014
EPA Reg + MSD/MAPP	2,107	2,098	2,114	2,132	2,117	2,136	2,137	2,118	2,065	2,014
Low Load + PJM EE	1,993	1,948	1,946	1,970	1,953	1,966	1,960	1,950	1,935	1,902
Med Renew + MSD	2,131	2,128	2,131	2,129	2,105	2,100	2,094	2,060	1,996	1,939
High Renew + EE/MSD	1,932	1,929	1,925	1,913	1,880	1,869	1,840	1,807	1,743	1,683
Life Xtsn + MSD	2,158	2,153	2,170	2,182	2,172	2,185	2,188	2,183	2,140	2,146

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Table 14.10 (cont.) Annual Mercury Emissions from Electricity Consumption in Maryland (pounds)*

	2010-2020 Average Annual Emissions	2021-2030 Average Annual Emissions	2010-2030 Average Annual Emissions	2010-2030 Cumulative Emissions
Reference Case	2,226	2,137	2,184	45,900
MSD	2,226	2,138	2,185	45,900
MAPP	2,226	2,137	2,184	45,900
CC3	2,225	2,137	2,183	45,800
MSD + MAPP	2,226	2,138	2,184	45,900
CC3 + NCO2	2,178	2,083	2,133	44,800
CC3/NCO2/MSD/MAPP	2,176	2,069	2,125	44,600
NCO2	2,179	2,085	2,134	44,800
NCO2 + MSD	2,176	2,071	2,126	44,600
High Gas	2,247	2,140	2,196	46,100
High Gas + MSD	2,247	2,140	2,196	46,100
Low Gas	2,179	2,119	2,150	45,200
Low Gas + MSD	2,178	2,119	2,150	45,200
High Load	2,269	2,200	2,236	47,000
High Load + MSD	2,269	2,199	2,235	46,900
High Load + CC3/NCO2/MSD/MAPP	2,233	2,177	2,206	46,300
Low Load	2,181	2,026	2,107	44,300
Low Load + MSD	2,182	2,027	2,108	44,300
Low Load + CC3/NCO2/MSD/MAPP	2,115	1,924	2,024	42,500
High Renew	2,225	2,012	2,123	44,600
High Renew + MSD	2,225	2,014	2,124	44,600
High Renew + CC3/NCO2	2,174	1,962	2,073	43,500
High Renew + CC3/NCO2/MSD/MAPP	2,174	1,948	2,067	43,400
EE	2,158	1,967	2,067	43,400
EE + MSD	2,158	1,967	2,067	43,400
EE + CC3/NCO2	2,103	1,898	2,006	42,100
EE + CC3/NCO2/MSD/MAPP	2,104	1,898	2,006	42,100
Climate Change	2,235	2,131	2,185	45,900
Climate Change + CC3/NCO2/MSD/MAPP	2,192	2,080	2,139	44,900
EPA Reg + MSD	2,214	2,104	2,162	45,400
EPA Reg + MSD/MAPP	2,214	2,104	2,162	45,400
Low Load + PJM EE	2,159	1,952	2,060	43,300
Med Renew + MSD	2,228	2,081	2,158	45,300
High Renew + EE/MSD	2,154	1,852	2,010	42,200
Life Xtsn + MSD	2,235	2,168	2,203	46,300

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

14.4.13 Greenhouse Gas Reduction Act

Table 14.11 presents a comparison of estimated GGRA baseline CO_2 emissions versus the estimated percentage change in emissions under each alternative scenario.[63] The baseline was developed from the 2006 MDE GGRA baseline values and adjusted to include only the CO_2 component, as the LTER modeling only estimates CO_2 emissions from grid-connected power plants in Maryland as calculated by the Ventyx model and does not incorporate other greenhouse gases or behind-the-meter generation sources. In the LTER Reference Case, Maryland's grid-connected power plant CO_2 emissions totaled about 28 million metric tons of CO_2 ("MMtCO_2") in 2010.

The CO_2 emissions presented in this section are consumption-based, and computed using the PJM-wide emissions mix adjusted for Maryland renewable energy requirements. Renewable energy is assumed to entail no CO_2 emissions. Additionally, the consumption data was adjusted to reflect transmission and distribution losses. A seven percent T&D loss factor was used to make the loss adjustment, which is based on average U.S. losses reported by the Energy Information Administration.[64]

For all scenarios and for all years, CO_2 emissions are below the 2006 GGRA baseline. By 2020, CO_2 emissions range between 12.0 percent below the 2006 GGRA baseline to 27.7 percent below the baseline. The lowest reduction (12.0 percent) is associated with the High Load scenario because power plants must run more to meet higher demand levels, which results in a net increase in CO_2 emissions relative to other scenarios. The scenarios exhibiting the greatest reduction relative to the 2020 baseline are those scenarios that include national carbon legislation coupled with aggressive energy efficiency in Maryland. The combination of lower energy consumption in Maryland and a lower-emitting fleet of power plants in PJM results in significantly lower CO_2 emissions compared to the LTER Reference Case.

By 2030, the percentage reductions relative to the 2030 GGRA baseline vary between 4.2 percent and 37.4 percent. The same factors contributing to the differentials in 2020 affect the differentials in 2030.

[63] The analogous data for the Supplemental Responsive Scenarios is shown in Appendix L, Table L-15.
[64] The same loss factor was used by MDE to calculate the 2006 GGRA baseline.

Table 14.11 Percentage Difference in Annual Consumption-Based CO_2 Emissions Compared to 2006 Base Line CO_2 Emissions*

Maryland CO2 Emissions (thousand tons)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2006 Base Line	46,335	46,335	46,335	46,335	46,335	46,335	46,335	46,335	46,335	46,335	46,335
MSD	-5.6%	-7.9%	-9.8%	-12.4%	-14.9%	-14.8%	-16.2%	-15.7%	-16.7%	-17.1%	-16.1%
MAPP	-5.6%	-7.9%	-9.8%	-12.4%	-14.9%	-14.8%	-16.2%	-15.7%	-16.6%	-17.0%	-16.0%
CC3	-5.6%	-7.9%	-9.8%	-12.4%	-14.9%	-14.8%	-16.2%	-15.7%	-16.7%	-17.5%	-16.9%
MSD + MAPP	-5.6%	-7.9%	-9.8%	-12.4%	-14.9%	-14.8%	-16.2%	-15.7%	-16.6%	-17.0%	-16.2%
CC3 + NCO2	-5.6%	-7.9%	-9.8%	-12.4%	-15.0%	-16.5%	-18.2%	-18.4%	-19.7%	-20.8%	-20.0%
CC3/NCO2/MSD/MAPP	-5.6%	-7.9%	-9.8%	-12.4%	-15.0%	-16.4%	-18.1%	-18.4%	-19.8%	-20.7%	-19.9%
NCO2	-5.6%	-7.9%	-9.8%	-12.4%	-15.0%	-16.5%	-18.2%	-18.4%	-19.7%	-20.3%	-19.1%
NCO2 + MSD	-5.6%	-7.9%	-9.8%	-12.4%	-15.0%	-16.4%	-18.1%	-18.4%	-19.8%	-20.2%	-19.2%
High Gas	-4.5%	-7.2%	-8.6%	-11.2%	-14.2%	-14.7%	-16.3%	-15.6%	-16.9%	-17.0%	-16.1%
High Gas + MSD	-4.5%	-7.2%	-8.6%	-11.2%	-14.2%	-14.7%	-16.3%	-15.6%	-17.0%	-17.1%	-16.1%
Low Gas	-8.6%	-10.7%	-12.3%	-14.4%	-16.3%	-15.5%	-16.9%	-16.2%	-17.1%	-17.6%	-16.2%
Low Gas + MSD	-8.6%	-10.7%	-12.3%	-14.4%	-16.3%	-15.5%	-16.9%	-16.2%	-17.1%	-17.7%	-16.3%
High Load	-5.6%	-7.4%	-8.8%	-11.1%	-13.2%	-12.4%	-13.3%	-12.1%	-13.2%	-13.0%	-12.0%
High Load + MSD	-5.6%	-7.4%	-8.8%	-11.1%	-13.2%	-12.4%	-13.3%	-12.1%	-13.2%	-13.1%	-12.0%
High Load + CC3/NCO2/MSD/MAPP	-5.6%	-7.4%	-8.8%	-11.2%	-13.3%	-14.1%	-15.2%	-14.6%	-15.4%	-15.9%	-14.6%
Low Load	-5.6%	-8.4%	-10.8%	-13.8%	-16.7%	-16.5%	-18.3%	-18.1%	-20.1%	-21.4%	-20.8%
Low Load + MSD	-5.6%	-8.4%	-10.8%	-13.8%	-16.7%	-16.5%	-18.3%	-18.1%	-20.1%	-21.4%	-20.8%
Low Load + CC3/NCO2/MSD/MAPP	-5.6%	-8.4%	-10.8%	-13.8%	-16.7%	-18.4%	-20.5%	-21.9%	-23.6%	-25.3%	-25.2%
High Renew	-5.6%	-7.9%	-9.8%	-12.4%	-14.9%	-14.8%	-16.2%	-15.7%	-16.7%	-17.4%	-16.8%
High Renew + MSD	-5.6%	-7.9%	-9.8%	-12.4%	-14.9%	-14.8%	-16.2%	-15.7%	-16.7%	-17.4%	-16.8%
High Renew + CC3/NCO2	-5.6%	-7.9%	-9.8%	-12.4%	-15.0%	-16.5%	-18.2%	-18.4%	-19.9%	-21.1%	-20.5%
High Renew + CC3/NCO2/MSD/MAPP	-5.6%	-7.9%	-9.8%	-12.4%	-15.0%	-16.4%	-18.1%	-18.4%	-19.8%	-20.9%	-20.4%
EE	-5.6%	-7.9%	-10.3%	-13.3%	-16.3%	-16.5%	-19.1%	-19.7%	-22.0%	-23.4%	-23.6%
EE + MSD	-5.6%	-7.9%	-10.3%	-13.3%	-16.3%	-16.5%	-19.1%	-19.7%	-22.0%	-23.4%	-23.6%
EE + CC3/NCO2	-5.6%	-7.9%	-10.3%	-13.4%	-16.3%	-18.1%	-20.9%	-22.4%	-25.1%	-27.4%	-27.7%
EE + CC3/NCO2/MSD/MAPP	-5.6%	-7.9%	-10.3%	-13.4%	-16.3%	-18.1%	-20.9%	-22.4%	-24.9%	-27.1%	-27.4%
Climate Change	-5.6%	-7.9%	-9.8%	-12.4%	-14.9%	-14.5%	-15.8%	-15.4%	-16.5%	-16.8%	-16.0%
Climate Chg + CC3/NCO2/MSD/MAPP	-5.6%	-7.9%	-9.8%	-12.4%	-15.0%	-16.1%	-17.8%	-17.9%	-19.2%	-19.9%	-19.2%
EPA Reg + MSD	-5.6%	-7.9%	-10.3%	-12.5%	-15.0%	-15.2%	-16.5%	-16.2%	-17.6%	-17.7%	-16.5%
EPA Reg + MSD/MAPP	-5.6%	-7.9%	-10.3%	-12.5%	-15.0%	-15.2%	-16.5%	-16.2%	-17.5%	-17.7%	-16.4%
Low Load + PJM EE	-5.6%	-8.8%	-11.5%	-14.8%	-17.9%	-17.8%	-20.1%	-20.2%	-22.2%	-23.3%	-23.0%
Med Renew + MSD	-5.6%	-7.9%	-9.8%	-12.3%	-14.9%	-14.8%	-16.2%	-15.6%	-16.5%	-17.1%	-16.4%
High Renew + EE/MSD	-5.6%	-7.9%	-10.3%	-13.3%	-16.3%	-16.5%	-19.1%	-19.7%	-22.0%	-23.8%	-24.1%
Life Xtsn + MSD	-5.6%	-7.9%	-9.8%	-12.3%	-14.7%	-14.5%	-15.9%	-15.3%	-16.2%	-16.7%	-15.6%

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Table 14.11 (cont.) Percentage Difference in Annual Consumption-Based CO_2 Emissions Compared to 2006 Base Line CO_2 Emissions*

Maryland CO2 Emissions (thousand tons)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2006 Base Line	46,335	46,335	46,335	46,335	46,335	46,335	46,335	46,335	46,335	46,335
MSD	-15.5%	-15.5%	-14.3%	-13.3%	-13.0%	-12.3%	-11.8%	-11.6%	-11.2%	-11.5%
MAPP	-15.4%	-15.4%	-14.2%	-13.1%	-12.9%	-12.2%	-11.6%	-11.4%	-11.0%	-11.3%
CC3	-16.4%	-16.3%	-15.1%	-14.1%	-13.8%	-13.0%	-12.6%	-12.3%	-11.8%	-12.1%
MSD + MAPP	-15.4%	-15.4%	-14.2%	-13.2%	-12.9%	-12.2%	-11.6%	-11.5%	-11.1%	-11.4%
CC3 + NCO2	-19.4%	-19.2%	-17.9%	-16.6%	-16.2%	-18.6%	-18.7%	-22.4%	-25.1%	-28.9%
CC3/NCO2/MSD/MAPP	-19.3%	-19.1%	-17.8%	-16.5%	-16.3%	-18.7%	-18.8%	-22.4%	-25.2%	-29.1%
NCO2	-18.3%	-18.4%	-17.0%	-15.6%	-15.3%	-18.0%	-18.0%	-21.8%	-24.5%	-28.4%
NCO2 + MSD	-18.5%	-18.2%	-17.1%	-15.7%	-15.4%	-19.2%	-18.2%	-22.0%	-24.8%	-28.7%
High Gas	-15.6%	-15.5%	-14.4%	-13.4%	-13.3%	-12.4%	-12.0%	-11.9%	-11.4%	-11.7%
High Gas + MSD	-15.5%	-15.5%	-14.5%	-13.4%	-13.2%	-12.5%	-12.0%	-11.9%	-11.5%	-11.8%
Low Gas	-15.7%	-15.8%	-14.7%	-13.5%	-13.5%	-12.3%	-12.0%	-11.9%	-10.8%	-11.2%
Low Gas + MSD	-15.6%	-15.7%	-14.8%	-13.5%	-13.4%	-12.2%	-11.9%	-11.8%	-10.9%	-11.2%
High Load	-10.8%	-10.3%	-8.9%	-7.2%	-6.4%	-5.4%	-4.6%	-4.5%	-4.0%	-4.2%
High Load + MSD	-10.9%	-10.4%	-8.9%	-7.3%	-6.6%	-5.6%	-4.9%	-4.8%	-4.3%	-4.5%
High Load + CC3/NCO2/MSD/MAPP	-13.6%	-13.0%	-11.4%	-9.7%	-8.7%	-12.4%	-11.7%	-15.3%	-18.6%	-21.9%
Low Load	-20.7%	-21.3%	-20.7%	-20.1%	-19.9%	-19.5%	-19.2%	-19.5%	-19.3%	-19.6%
Low Load + MSD	-20.7%	-21.3%	-20.7%	-20.1%	-19.9%	-19.6%	-19.2%	-19.5%	-19.4%	-19.6%
Low Load + CC3/NCO2/MSD/MAPP	-25.2%	-25.6%	-25.0%	-24.3%	-24.0%	-26.4%	-27.3%	-30.2%	-31.0%	-37.1%
High Renew	-17.0%	-17.1%	-16.9%	-17.0%	-17.9%	-18.2%	-18.9%	-19.7%	-20.4%	-21.7%
High Renew + MSD	-17.0%	-17.1%	-17.0%	-17.1%	-17.9%	-18.2%	-18.9%	-19.7%	-20.6%	-21.8%
High Renew + CC3/NCO2	-20.8%	-20.9%	-20.4%	-20.2%	-20.9%	-24.2%	-25.2%	-29.4%	-32.8%	-37.2%
High Renew + CC3/NCO2/MSD/MAPP	-20.8%	-20.8%	-20.5%	-20.3%	-21.0%	-24.2%	-25.3%	-29.5%	-33.0%	-37.4%
EE	-23.1%	-22.9%	-21.7%	-20.7%	-20.3%	-19.6%	-19.1%	-19.0%	-18.4%	-18.6%
EE + MSD	-23.1%	-22.9%	-21.8%	-20.8%	-20.5%	-19.7%	-19.1%	-18.9%	-18.5%	-18.7%
EE + CC3/NCO2	-26.9%	-26.8%	-25.3%	-24.1%	-23.6%	-25.9%	-25.9%	-29.0%	-31.9%	-35.5%
EE + CC3/NCO2/MSD/MAPP	-26.8%	-26.5%	-25.3%	-24.0%	-23.6%	-26.8%	-25.8%	-28.8%	-31.9%	-35.5%
Climate Change	-15.2%	-15.2%	-14.2%	-12.7%	-12.3%	-11.6%	-11.2%	-11.3%	-11.0%	-11.3%
Climate Chg + CC3/NCO2/MSD/MAPP	-18.6%	-18.6%	-17.3%	-15.6%	-15.1%	-18.8%	-17.9%	-22.3%	-24.7%	-28.7%
EPA Reg + MSD	-15.9%	-15.9%	-14.8%	-13.5%	-13.3%	-12.4%	-11.9%	-11.6%	-11.6%	-11.9%
EPA Reg + MSD/MAPP	-15.8%	-15.8%	-14.7%	-13.5%	-13.3%	-12.2%	-11.8%	-11.6%	-11.5%	-11.8%
Life Xtsn + MSD	-22.8%	-24.0%	-23.9%	-23.0%	-23.3%	-23.0%	-23.0%	-23.2%	-23.0%	-23.2%
High Renew + EE/MSD	-16.2%	-16.1%	-15.6%	-15.1%	-15.3%	-15.2%	-15.2%	-15.5%	-15.7%	-16.4%
Low Load + PJM EE	-24.5%	-24.3%	-24.1%	-24.1%	-24.8%	-25.0%	-25.6%	-26.3%	-27.0%	-28.1%
Med Renew + MSD	-15.1%	-15.1%	-13.8%	-12.8%	-12.7%	-11.8%	-11.2%	-11.0%	-10.4%	-9.2%

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Table 14.11 (cont.) Percentage Difference in Annual Consumption-Based CO_2 Emissions Compared to 2006 Base Line CO_2 Emissions*

Maryland CO2 Emissions (thousand tons)	2010-2020 Average Annual Emissions	2021-2030 Average Annual Emissions	2010-2030 Average Annual Emissions	2010-2030 Cumulative Emissions
2006 Base Line	46,335	46,335	46,335	973,035
MSD	-13.4%	-13.0%	-13.2%	-13.2%
MAPP	-13.4%	-12.8%	-13.1%	-13.1%
CC3	-13.5%	-13.8%	-13.6%	-13.6%
MSD + MAPP	-13.4%	-12.9%	-13.1%	-13.1%
CC3 + NCO2	-14.9%	-20.3%	-17.5%	-17.5%
CC3/NCO2/MSD/MAPP	-14.9%	-20.3%	-17.5%	-17.5%
NCO2	-14.8%	-19.5%	-17.0%	-17.0%
NCO2 + MSD	-14.8%	-19.8%	-17.2%	-17.2%
High Gas	-12.9%	-13.2%	-13.0%	-13.0%
High Gas + MSD	-13.0%	-13.2%	-13.1%	-13.1%
Low Gas	-14.7%	-13.1%	-14.0%	-14.0%
Low Gas + MSD	-14.7%	-13.1%	-13.9%	-13.9%
High Load	-11.1%	-6.6%	-9.0%	-9.0%
High Load + MSD	-11.1%	-6.8%	-9.1%	-9.1%
High Load + CC3/NCO2/MSD/MAPP	-12.4%	-13.6%	-13.0%	-13.0%
Low Load	-15.5%	-20.0%	-17.6%	-17.6%
Low Load + MSD	-15.5%	-20.0%	-17.6%	-17.6%
Low Load + CC3/NCO2/MSD/MAPP	-17.3%	-27.6%	-22.2%	-22.2%
High Renew	-13.5%	-18.5%	-15.9%	-15.9%
High Renew + MSD	-13.5%	-18.5%	-15.9%	-15.9%
High Renew + CC3/NCO2	-15.0%	-25.2%	-19.9%	-19.9%
High Renew + CC3/NCO2/MSD/MAPP	-15.0%	-25.3%	-19.9%	-19.9%
EE	-16.1%	-20.3%	-18.1%	-18.1%
EE + MSD	-16.1%	-20.4%	-18.2%	-18.2%
EE + CC3/NCO2	-17.7%	-27.5%	-22.4%	-22.4%
EE + CC3/NCO2/MSD/MAPP	-17.7%	-27.5%	-22.3%	-22.3%
Climate Change	-13.2%	-12.6%	-12.9%	-12.9%
Climate Chg + CC3/NCO2/MSD/MAPP	-14.6%	-19.8%	-17.1%	-17.1%
EPA Reg + MSD	-13.7%	-13.3%	-13.5%	-13.5%
EPA Reg + MSD/MAPP	-13.7%	-13.2%	-13.5%	-13.5%
Low Load + PJM EE	-16.9%	-23.2%	-19.9%	-19.9%
Med Renew + MSD	-13.4%	-15.6%	-14.5%	-14.5%
High Renew + EE/MSD	-16.2%	-25.4%	-20.6%	-20.6%
Life Xtsn + MSD	-13.1%	-12.3%	-12.7%	-12.7%

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

14.5 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.

14.5.1 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 through 2020) followed by much slower growth, and in some cases negative growth, in the second half of the study period (2020 through 2030). Table 14.12 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 PJM-APS follow the same general pattern, with faster growth in the first ten years of the study period followed by much slower growth in the second half.

The asymmetric growth pattern over the 2010 through 2030 study period is largely the result of declines in excess generating capacity over the 2010 through 2020 period. As the initial capacity surpluses in PJM erode, 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 efficient new natural gas capacity.

Table 14.12 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
EPA Reg + MSD	4.19	0.43	2.29	4.16	0.29	2.21	4.79	0.26	2.50
EPA Reg + MSD/MAPP	4.33	0.30	2.29	4.14	0.23	2.16	4.89	0.19	2.51
Low Load + PJM EE	2.76	2.59	2.67	3.09	1.93	2.51	3.22	2.46	2.84
Medium Renew + MSD	4.37	0.19	2.26	4.17	0.34	2.24	4.89	0.13	2.48
High Renew + EE/MSD	4.22	0.26	2.22	4.31	0.14	2.20	4.79	0.26	2.50
Life Extension + MSD	4.27	0.27	2.25	4.13	0.40	2.25	4.80	0.21	2.48

LTER Reference Case all-hours prices grow at an average annual rate of 2.31 percent in PJM-SW over the 2010 through 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 all-hours wholesale prices to rise by approximately one percentage point 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 allowance costs 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 due to fewer new, efficient natural gas units being added during the study period under the low load growth scenarios. For example, approximately 30 GW of new natural gas capacity comes on-line by 2030 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 all-hours 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 all-hours 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 percentage points, respectively.

14.5.2 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 14.13 shows how the real average annual on-peak price compares to the real average annual 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. 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 capacity.

Table 14.13 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
EPA Reg + MSD	54.9	34.8	43.6	27.5	56.1	31.4
EPA Reg + MSD/MAPP	50.5	32.7	45.1	29.5	52.2	31.9
Low Load + PJM EE	48.7	47.1	34.3	37.2	49.1	45.8
Medium Renew + MSD	58.4	35.1	43.9	30.8	58.7	33.3
High Renew + EE/MSD	55.9	34.2	46.8	30.9	58.2	33.8
Life Extension + MSD	53.8	35.5	43.6	31.1	55.3	32.9

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)*100).

The LTER Reference Case 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 2020.[65] 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 consumes 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. In general, 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 normal or high. When natural gas prices are low, more natural gas units are built and operate as base load plants. As a result, periods of high demand are increasingly served by less efficient units with higher running costs.

14.5.3 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 tend to reach their peak in July. Wholesale prices are lowest in the shoulder periods just before and after the summer months. Figure 14.25 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 observed across all scenarios.

[65] 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.

Figure 14.25 LTER Reference Case Monthly Average All-Hours Energy Price

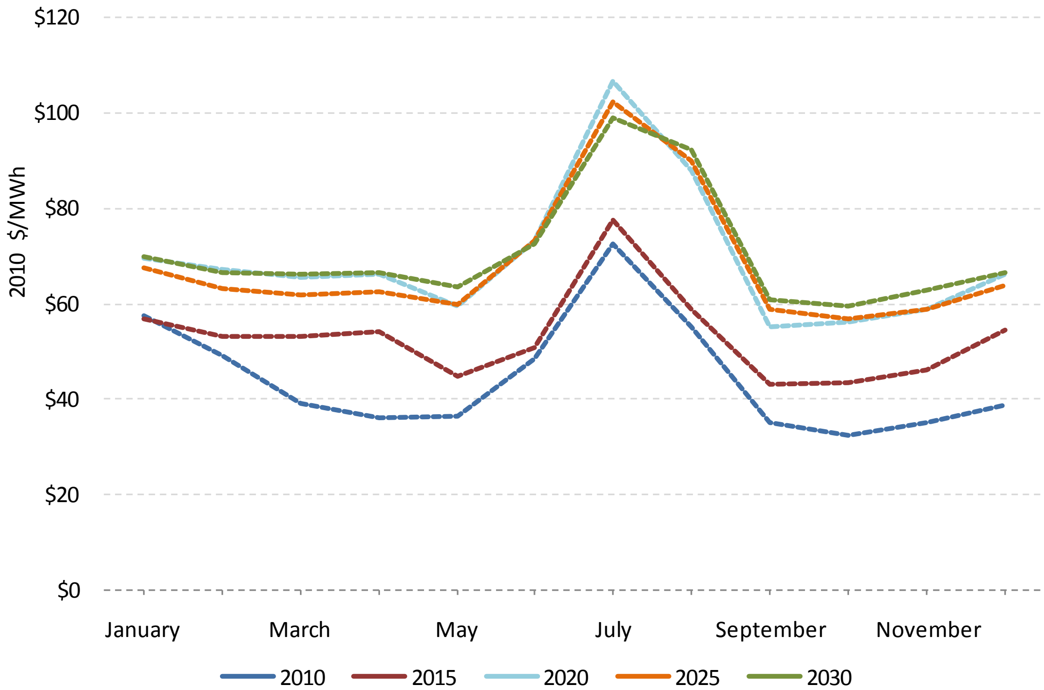


Table 14.14 shows the ratio of the highest and lowest all-hours average monthly price for the years 2020 and 2030 (“Seasonal Ratio”). This Seasonal Ratio is a measure of the variability of monthly all-hours real energy prices within a given year and the ratio increases as the maximum and minimum monthly average prices diverge. The maximum price occurs each year in the summer while the minimum price occurs in the fall.

Table 14.14 Seasonal Price Variability: Ratio of Highest and Lowest Monthly Real All-Hours 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
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
High Renew	2.00	1.65	1.65	1.55	1.70	1.51
High Renew + MSD	1.90	1.63	1.67	1.59	1.84	1.57
High Renew + CC3/NCO2	1.75	1.46	1.64	1.41	1.70	1.47
High Renew + CC3/NCO2/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 + CC3/ NCO2	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
EPA Reg + MSD	1.93	1.63	1.83	1.51	1.89	1.49
EPA Reg + MSD/MAPP	1.84	1.56	1.84	1.51	1.80	1.49
Low Load + PJM EE	1.71	1.79	1.59	1.56	1.68	1.65
Medium Renew + MSD	1.93	1.64	1.66	1.60	1.84	1.56
High Renew + EE/MSD	1.77	1.61	1.58	1.58	1.76	1.57
Life Extension + MSD	1.84	1.63	1.65	1.58	1.79	1.53

LTER seasonal ratios for 2010 are excluded from Table 14.14 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, given that zone's significant coal and relatively mild summer weather.

The seasonal ratios exhibit a similar pattern to on-peak/off-peak load variability with increases in the 2010 through 2020 period followed by decreases 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 previous 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.

14.6 PJM Production Costs and Revenues

14.6.1 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 14.15). 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 14.15 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

*The Ventyx model only produces capital costs for new generic natural gas capacity.

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 that may be allocated 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 3. 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 $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 power plants 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.

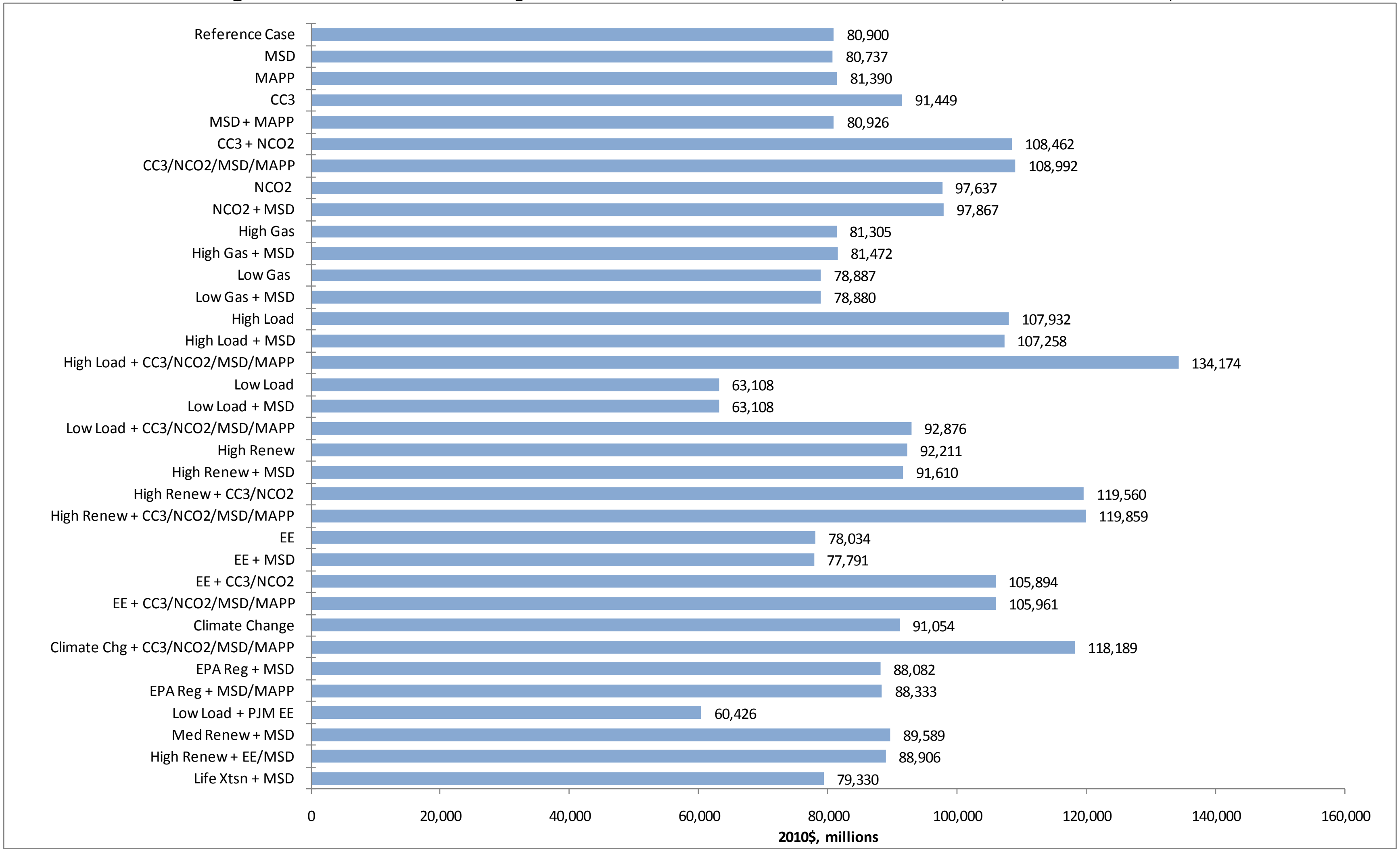
The PJM revenue projections presented in this section include both energy and capacity revenues. Excluded from the calculations are revenues associated with the sale of ancillary services, which is a relatively minor component.

14.6.2 Cost and Revenue Graphs

Based on the aforementioned assumptions, capital costs, production costs, and energy revenues were calculated to facilitate comparisons across scenarios. Figure 14.26 displays generic capital costs of new generation in PJM during the study period; Figure 14.27 and Figure 14.28 show energy production costs and revenues, respectively; and Figure 14.29 displays the sum of production costs and capital costs accumulated over the full 20-year study period.[66]

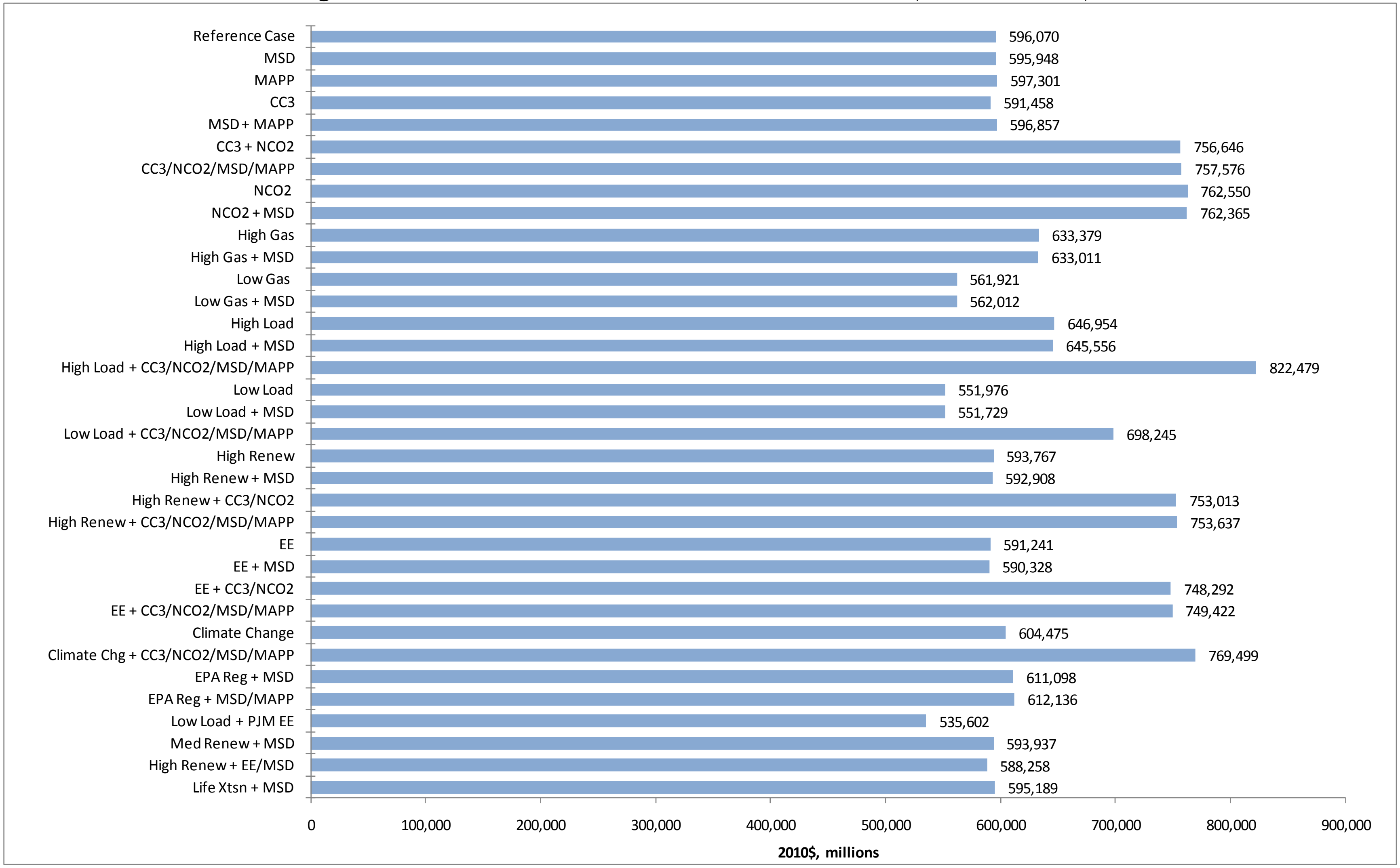
[66] Analogous data for the four Supplemental Responsive Scenarios are shown in Appendix L, Table L-16.

Figure 14.26 Total PJM Capital Costs of New Generation, 2010 – 2030 (2010$, millions)*



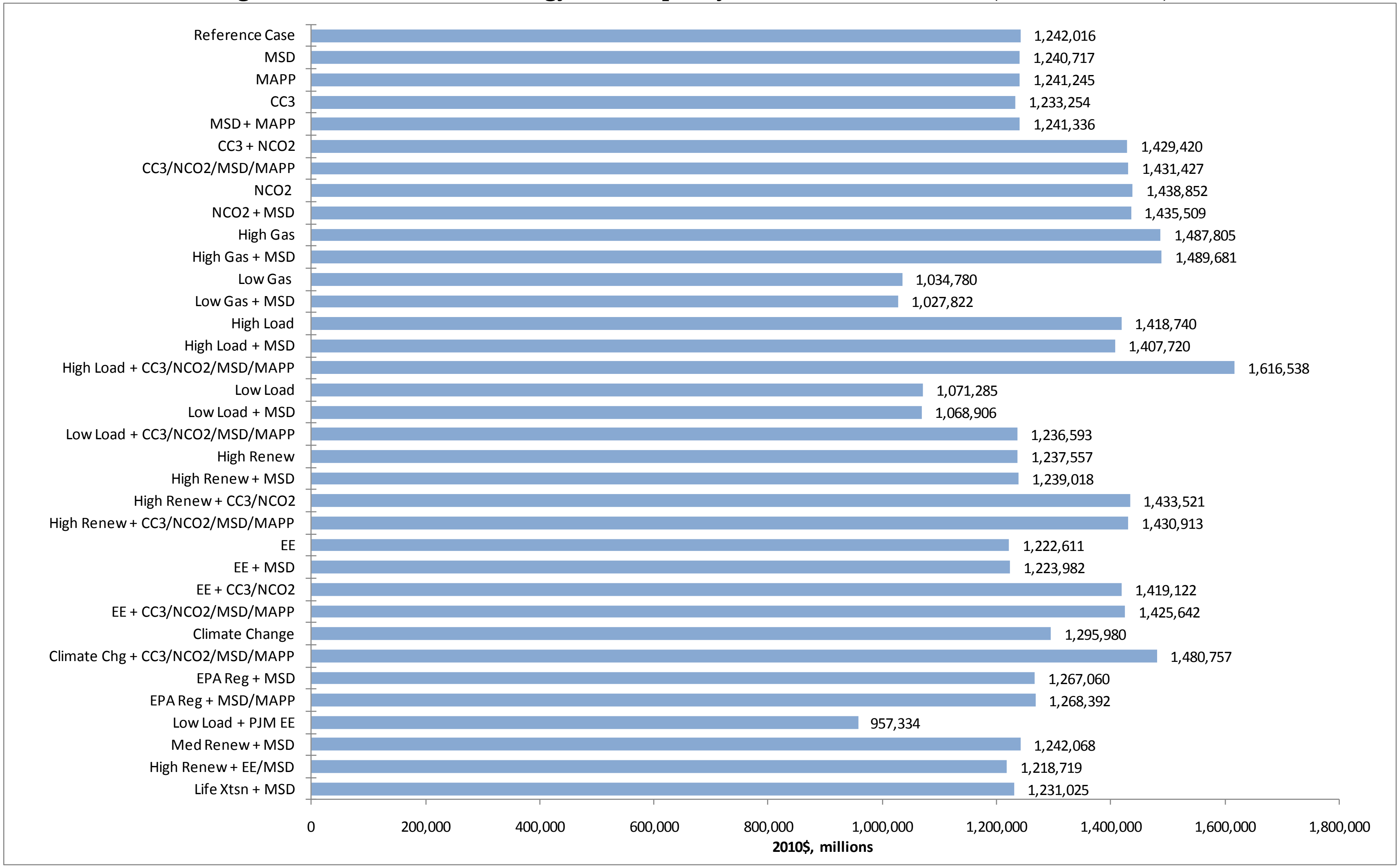
*Total PJM capital costs are based on the levelized capital costs of new generation (i.e., generic gas builds, renewable energy projects, and Calvert Cliffs 3). The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.27 Total PJM Production Costs, 2010 – 2030 (2010$, millions)*



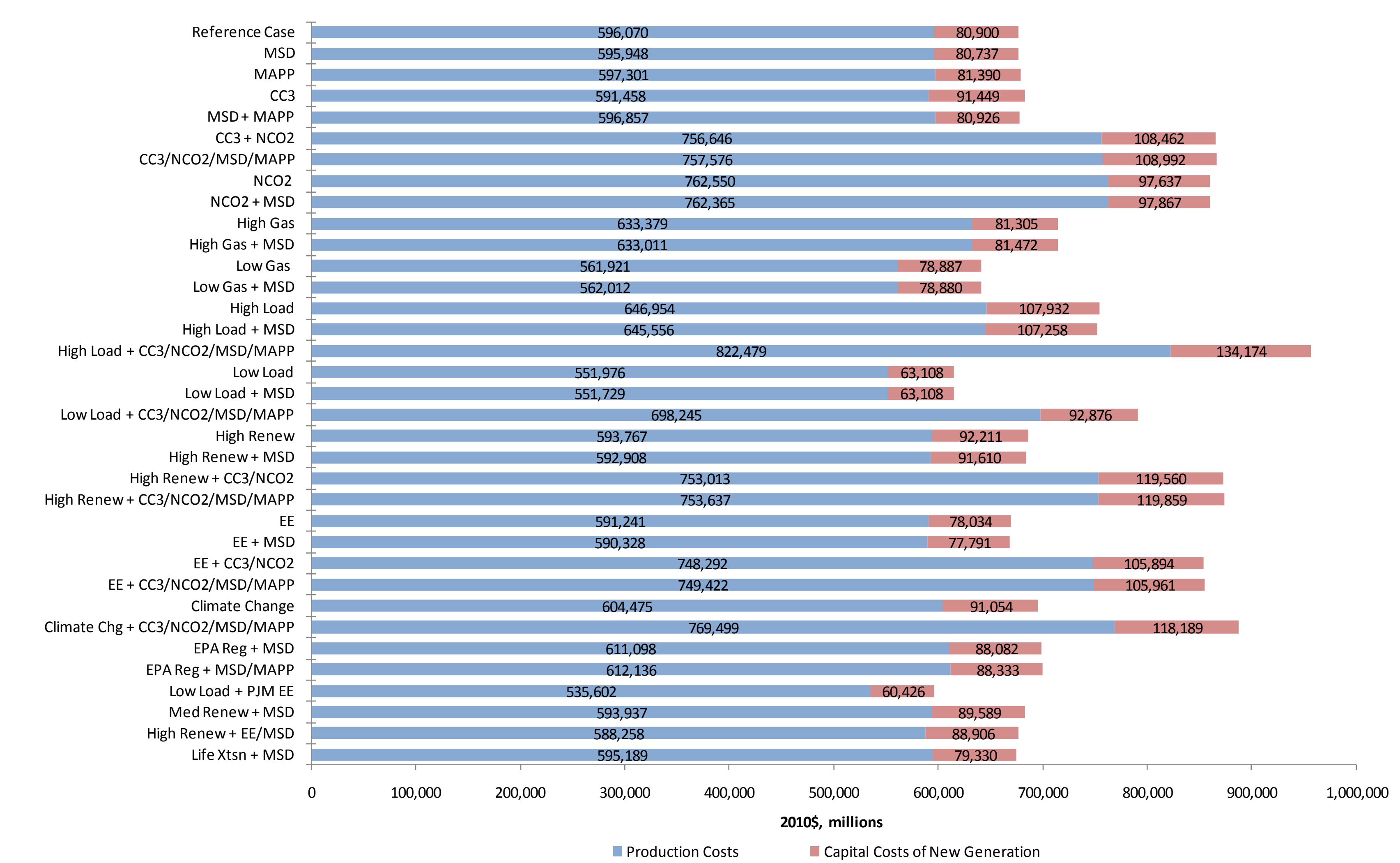
*Production costs include variable and fixed O&M costs, fuel costs, and emissions costs.
The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.28 Total PJM Energy Plus Capacity Revenues, 2010 – 2030 (2010$, millions)*



*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.29 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). The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

14.6.3 Capital Costs in PJM

As explained above, capital costs in PJM represent the costs of generic infrastructure (i.e., new natural gas units) added in each scenario, Calvert Cliffs 3 capital costs, and the capital costs associated with new renewable energy projects. The principal underlying factors affecting the magnitude of capital costs in PJM include load levels, whether national carbon legislation is introduced, whether Calvert Cliffs 3 is constructed, EPA regulatory requirements, energy efficiency program implementation on a PJM-wide basis, 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 Medium and 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. Under the EPA scenarios, we observe an increase in total capital costs, relative to the LTER Reference Case. This occurs because certain existing capacity resources are either retired earlier or de-rated due to the installation of new emissions controls, therefore increasing the need for new capacity. Under the Low Load and PJM-wide Energy Efficiency scenario, we observe the largest reduction in total capital costs relative to the LTER Reference Case. The combination of energy efficiency and low loads throughout the PJM region entails much lower demand for new capacity; thus this scenario results in the lowest level of capital costs.

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.

14.6.4 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 (e.g., the High Load scenarios), production costs are increased relative to the LTER Reference Case. In the scenarios with lower levels of energy consumption, production costs are lower than in the LTER Reference Case. This decrease is most distinctive under the Low Load and PJM-wide Energy Efficiency scenario. 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.

14.6.5 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 overall 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.

14.7 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.

14.7.1 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 FERC. If FERC determines 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.

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.

14.7.2 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.[67] 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.

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

[67] A PPA can contain clauses that effectively cause the price risk to be shared by the buyer and the seller.

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.

14.7.3 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, and total production cost), but does not capture the costs of program implementation.

14.7.4 Increased Renewable Energy Requirements

Two of the variations to the LTER Reference Case entail 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. Under the Medium Renewables scenario, the Maryland RPS is assumed to increase by an amount resulting in an aggregate RPS requirement about halfway between the LTER Reference Case and the High Renewables scenarios.

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,[68] 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

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

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 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 RECs. 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 purchases 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 14.8, which follows below.

14.8 Renewable Energy Certificate Prices

As addressed in Section 14.7.4, 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 REC 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 REC price is equal to costs (including a reasonable return on investment) 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. The marginal renewable energy project is assumed to be an on-shore wind facility and the estimated REC prices were computed on that basis.

REC 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 14.16, below, shows the annual REC prices derived from the gap analysis for a set of representative scenarios.

Table 14.16 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 REC 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 REC prices. Between 2015 and 2023, REC prices are stable (between $24 and $26), as increases in renewable energy 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), REC 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 on RECs associated with the increase in demand are offset with the price impacts associated with the increase in supply, resulting in similar REC prices in the two scenarios (the LTER Reference Case and the High Renewables Scenario).

When 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 REC 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 REC 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 REC 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 REC prices.

Under the Low Natural Gas Price Scenario, REC 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 REC price using the gap analysis methodology. Under the Low Natural Gas Price scenario, nominal REC 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 14.16. 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 ACP is a non-binding constraint on REC prices in Maryland.

As noted previously in this section, there is significant uncertainty associated with the estimated REC prices shown in Table 14.16. 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 REC 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 ACPs, (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 REC 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 credit foregone.

In Table 14.16, 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 PTC) and therefore would be competitive with conventional (natural gas) technologies. 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. However, 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 renewable power generators.

14.9 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 during off-peak periods when market energy prices are low, and then used 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 small number energy companies are beginning to test the use of batteries for grid management and energy storage. For example, 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 the tank used to hold the liquid. A 1 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 1 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 1 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 14.30 below, outlines the status of energy storage in PJM, both existing and planned. As shown in Figure 14.30, 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 be effectively modeled. The implications of technological advances, reduced costs, and more widespread application of storage will be addressed in future LTERs as information becomes available.

Figure 14.30 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

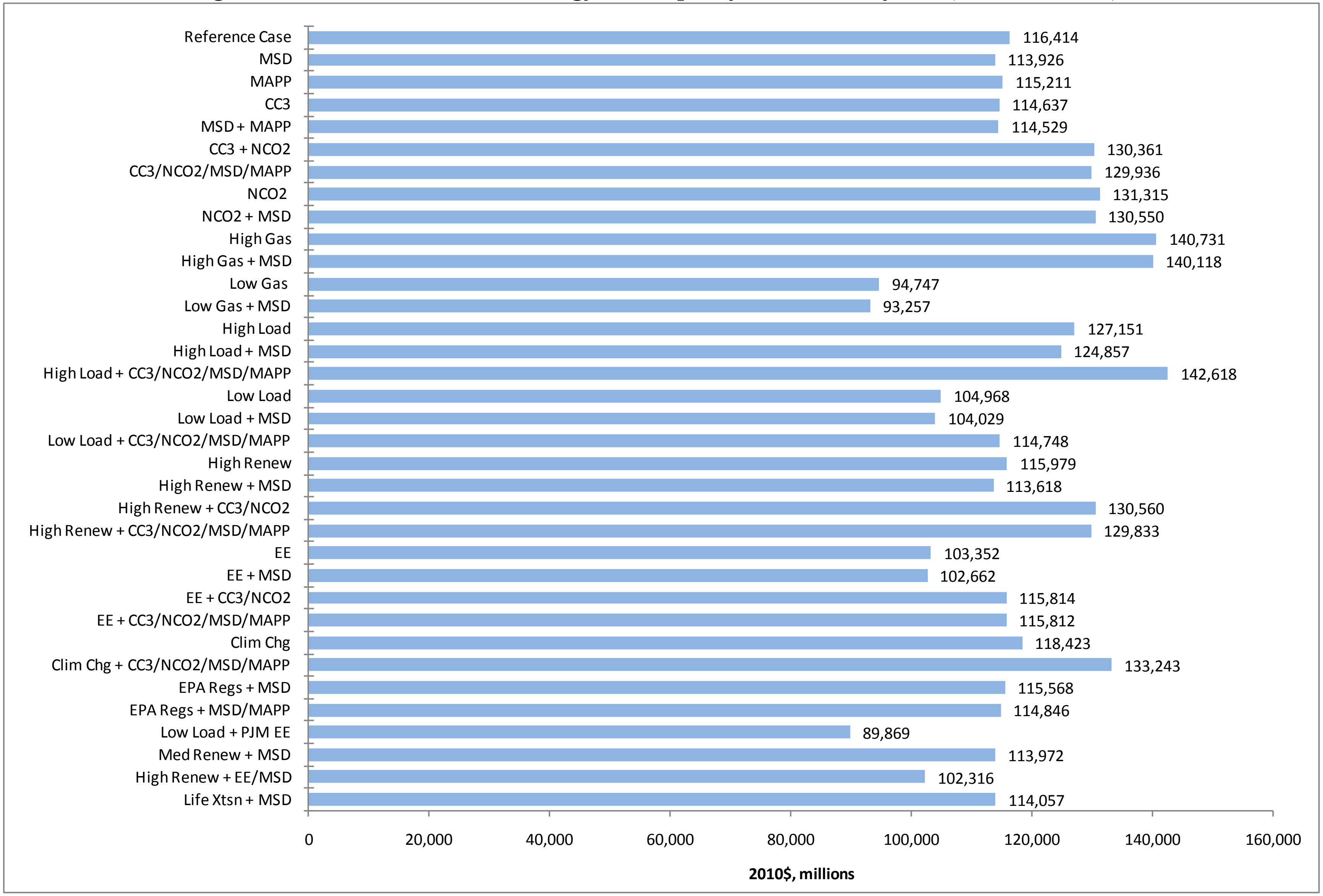
Source: PJM: http://www.pjm.com/~/media/committees-groups/committees/mrc/20100805/20100805-item-10b-limited-energy-resources.ashx

14.10 Maryland Energy and Capacity Costs

Figure 14.31 presents the sum of the wholesale energy and capacity costs in Maryland for the full study period, in each of the LTER scenarios; Figure 14.32 displays each scenario's cost differential from the LTER Reference Case (i.e., total wholesale energy and capacity costs in each scenario minus total costs in the LTER Reference Case). The data shown in Figure 14.32 can be interpreted as the marginal cost impacts for energy and capacity in each scenario relative to the LTER Reference Case.[69]

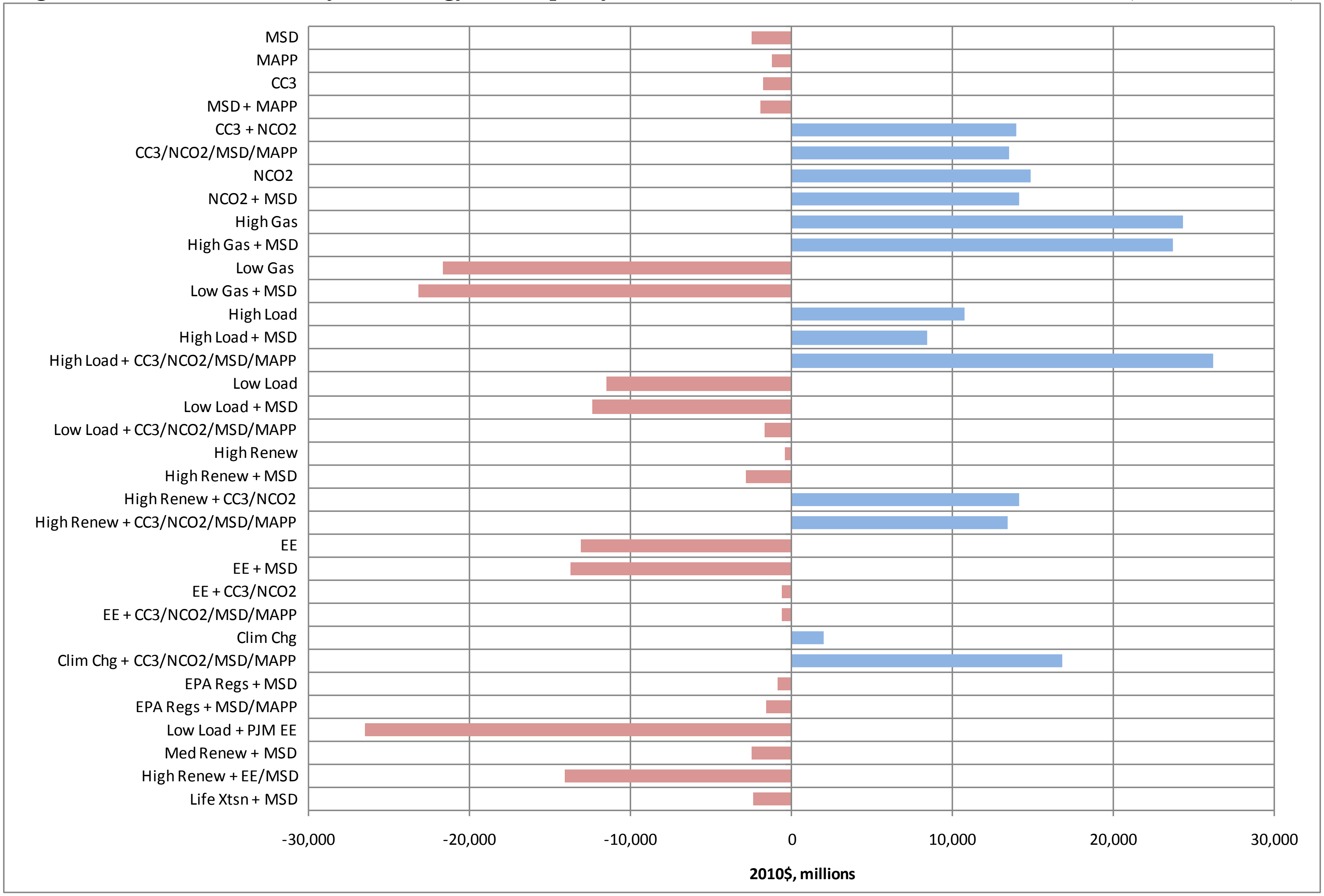
[69] Analogous data for the four Supplemental Responsive Scenarios are shown in Appendix L, Table L-17.

Figure 14.31 2010 - 2030 Total Energy and Capacity Costs in Maryland (2010$, millions)*



*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.32 2010 - 2030 Maryland Energy and Capacity Costs—Differential from LTER Reference Case (2010$, millions)*



*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

14.10.1 Methodology

For each scenario, total wholesale energy costs are estimated by summing the projected annual energy costs in Maryland for each year during the study period. Annual energy costs are estimated as the product of in-State energy consumption (MWh) and the all-hours energy price ($/MWh in $2010). In Maryland, however, there are three different all-hours energy prices each year because Maryland consists of three different transmission zones: PJM-SW, PJM-MidE, and PJM-APS. As such, the State's projected levels of annual energy consumption are differentiated into these three zones, using zonal weights that were developed for this analysis.[70]

A similar approach is used to project total capacity costs for Maryland. To estimate annual capacity costs in each zone in the State, Maryland's estimated annual peak demand is allocated among the three zones.[71] The annual capacity cost in each zone is estimated as the product of the zonal peak demand (MW), a reserve margin of 15 percent, the relevant capacity price ($/MW-day in $2010) in each zone, and 365 (days). No adjustment was made for peak demand diversity.

14.10.2 Results

In the LTER Reference Case, total wholesale energy and capacity costs in Maryland are estimated to be about $116 billion (in 2010 dollars[72]) during the course of the 20-year study period. Over 80 percent of these costs are attributed to energy, which is projected to cost Marylanders approximately $96 billion from 2010 to 2030. In general, the total cost of energy in Maryland increases on an annual basis. During the first half of the study period, annual energy costs in Maryland range from approximately $2.8 billion to $5.1 billion. The substantial increase in energy costs during this part of the study period is the result of annually increasing energy consumption and increasing fuel prices. Increases in annual energy costs begin to level off during the second half of the study period, ranging from $5.1 billion to about $5.75 billion from 2020 to 2030 as annual increases in fuel prices level off.

On an annual basis, total capacity costs in Maryland range from about $500 million to more than $1.5 billion in the LTER Reference Case. Total capacity costs depend on the annual capacity prices in each PJM zone and Maryland's share of the projected peak demand in each zone. Unlike energy prices, capacity prices do not consistently increase on an annual basis so capacity costs do not necessarily increase annually.

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[70] The zonal weights were derived from the Maryland Public Service Commission's *Ten Year Plan (2010-2019) of Electric Companies in Maryland*. The 2009 actual energy sales for each utility were used to calculate total energy consumption in each PJM zone in Maryland. The zonal totals were divided by the Maryland total to produce weights for PJM-SW, PJM-MidE, and PJM-APS.
[71] The same report was used to calculate the zonal shares of Maryland's 2009 peak demand.
[72] Unless otherwise noted, all costs in this section are in terms of 2010 dollars.

In the alternative infrastructure scenarios (MSD, MAPP, CC3, and MSD+MAPP), there are no significant deviations from the total energy costs observed in the LTER Reference Case. In each of these scenarios, however, the total capacity costs for Maryland are slightly lower than in the LTER Reference Case, which can be primarily attributed to the reduced capacity prices in the PJM-SW zone.

The National Carbon Legislation scenarios result in higher energy costs for the State (as compared to the LTER Reference Case), attributable to the increased energy prices associated with the implementation of national carbon legislation. In the alternative natural gas price scenarios, total energy costs are reflective of the assumptions embedded in each scenario. That is, higher natural gas prices equate to higher energy costs in Maryland, and lower natural gas prices result in lower energy costs in the State.

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 in response to a given percentage change in price (over time, if electricity prices increase, consumers will typically consume less electricity, other factors held constant). Because the model does not capture price elasticity effects, the energy consumption levels may be slightly overstated in the scenarios with higher energy prices and slightly understated in the scenarios with lower energy prices. For example, in the high natural gas price scenarios, electricity prices are higher than in the LTER Reference Case and, as a result, consumption (and therefore total energy costs) would be lower if price elasticity impacts are recognized. Conversely, with low natural gas prices, electricity prices are lower than in the LTER Reference Case and hence consumption (and total energy costs) would be higher, other factors held constant.

As compared to the LTER Reference Case, the State consumes more energy under the High Load scenarios; therefore total energy costs are higher for these scenarios. The Low Load scenarios have lower total energy costs for Maryland as a result of lower levels of energy consumption. Similarly, under the Aggressive Energy Efficiency scenarios, total energy costs are lower than in the LTER Reference Case, resulting from the reduced levels of energy consumption in the State. Note, however, that the costs of the energy efficiency and conservation programs implemented to achieve the savings are not included in the accounting.

Figure 14.33 displays total energy costs and Figure 14.34 displays each scenario's total energy cost differential compared to the LTER Reference Case. Figure 14.35 displays total capacity costs and Figure 14.36 displays each scenario's total capacity cost differential compared to the LTER Reference Case.[73]

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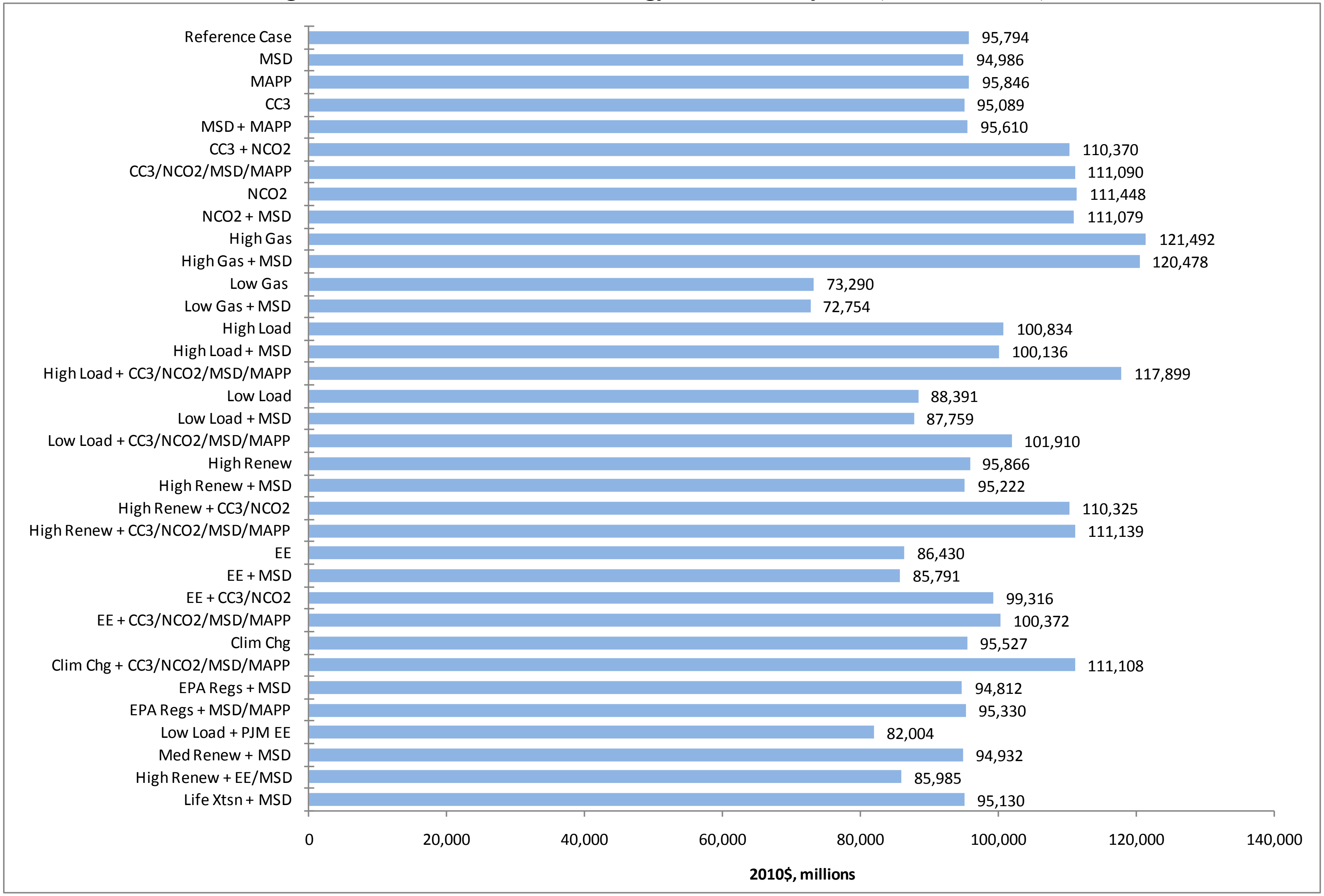
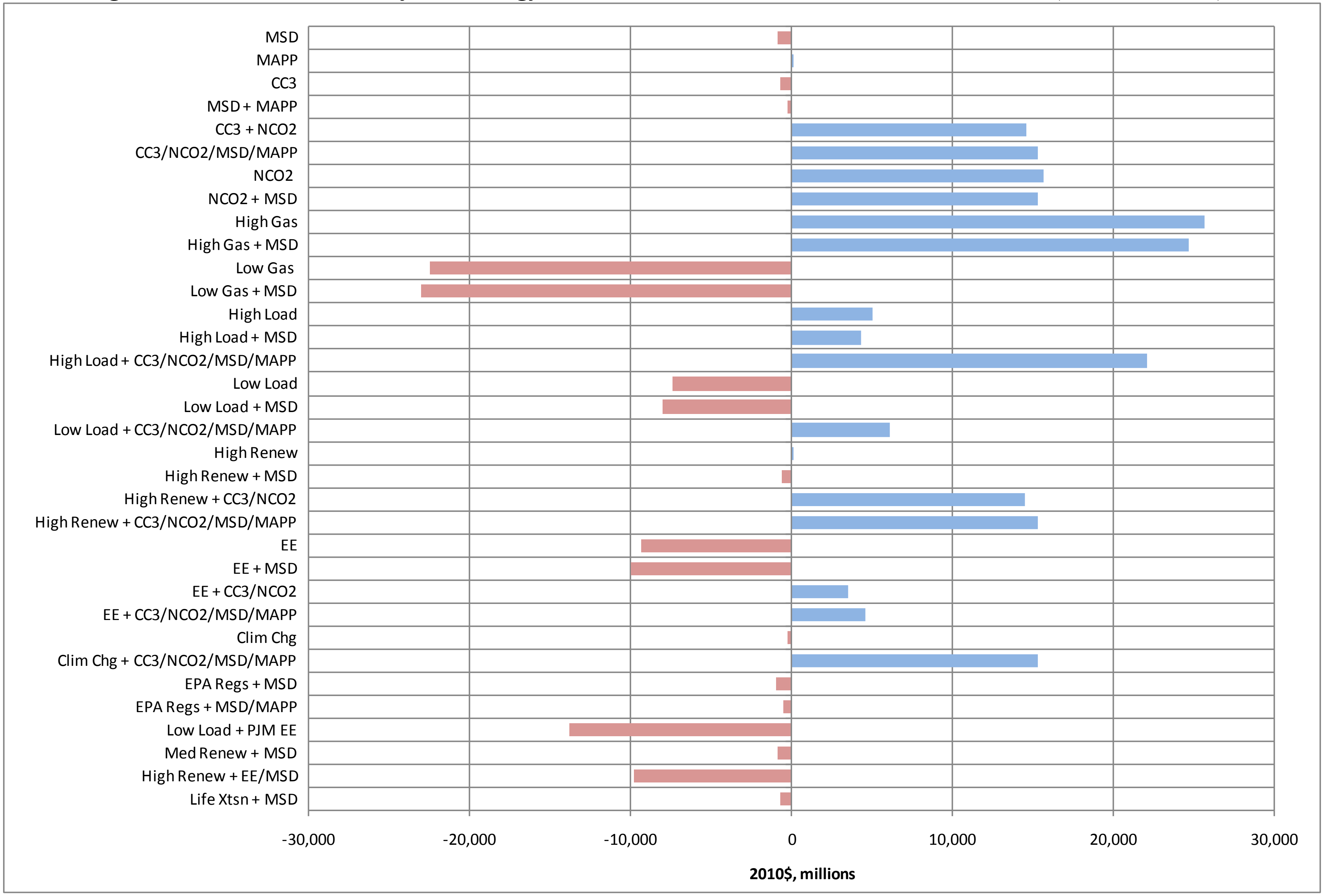
[73] Analogous data for the Supplemental Responsive Scenarios is presented in Appendix L, Table L-17.

Figure 14.33 2010 - 2030 Total Energy Costs in Maryland (2010$, millions)*



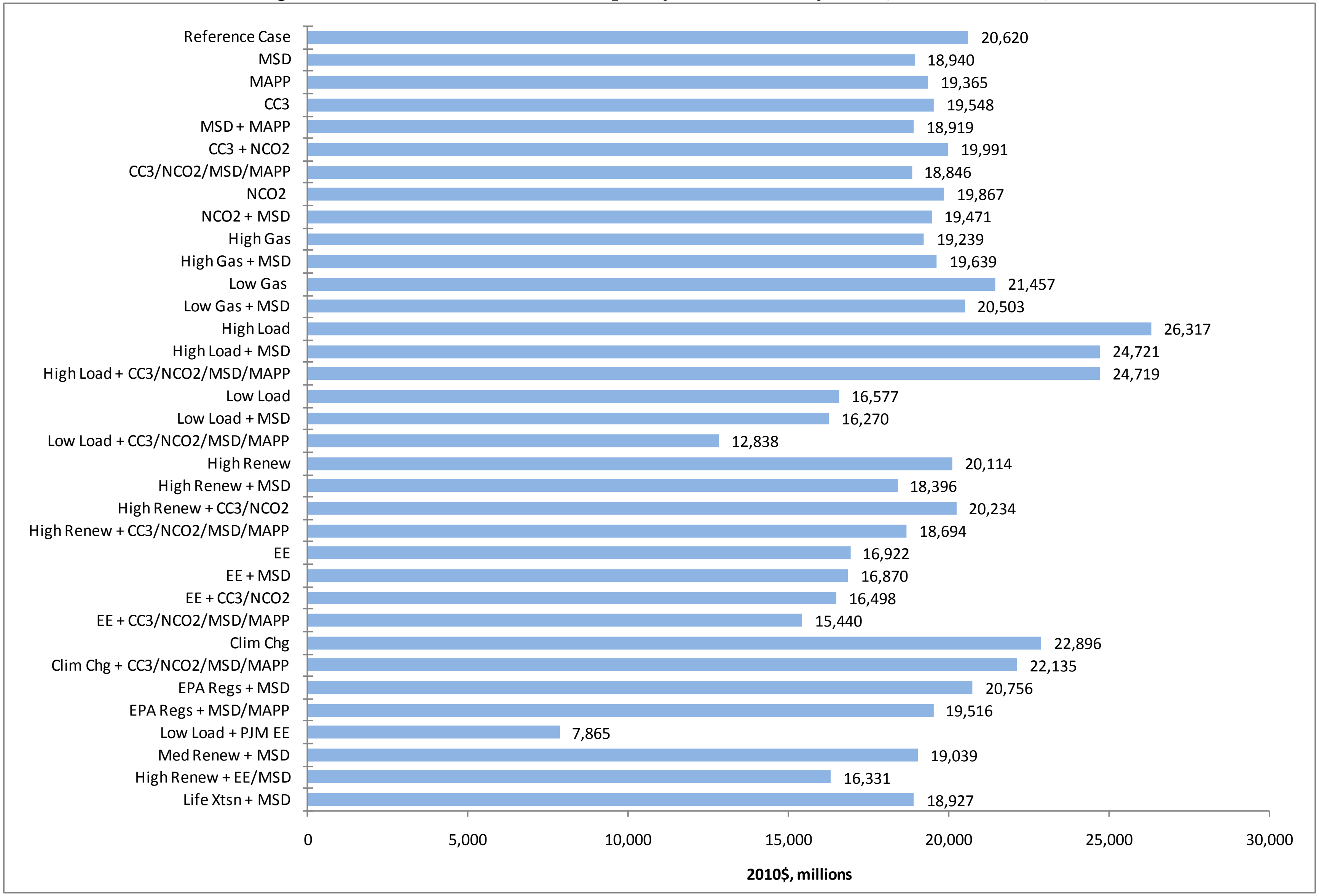
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.34 2010 - 2030 Maryland Energy Costs—Differential from LTER Reference Case (2010$, millions)*



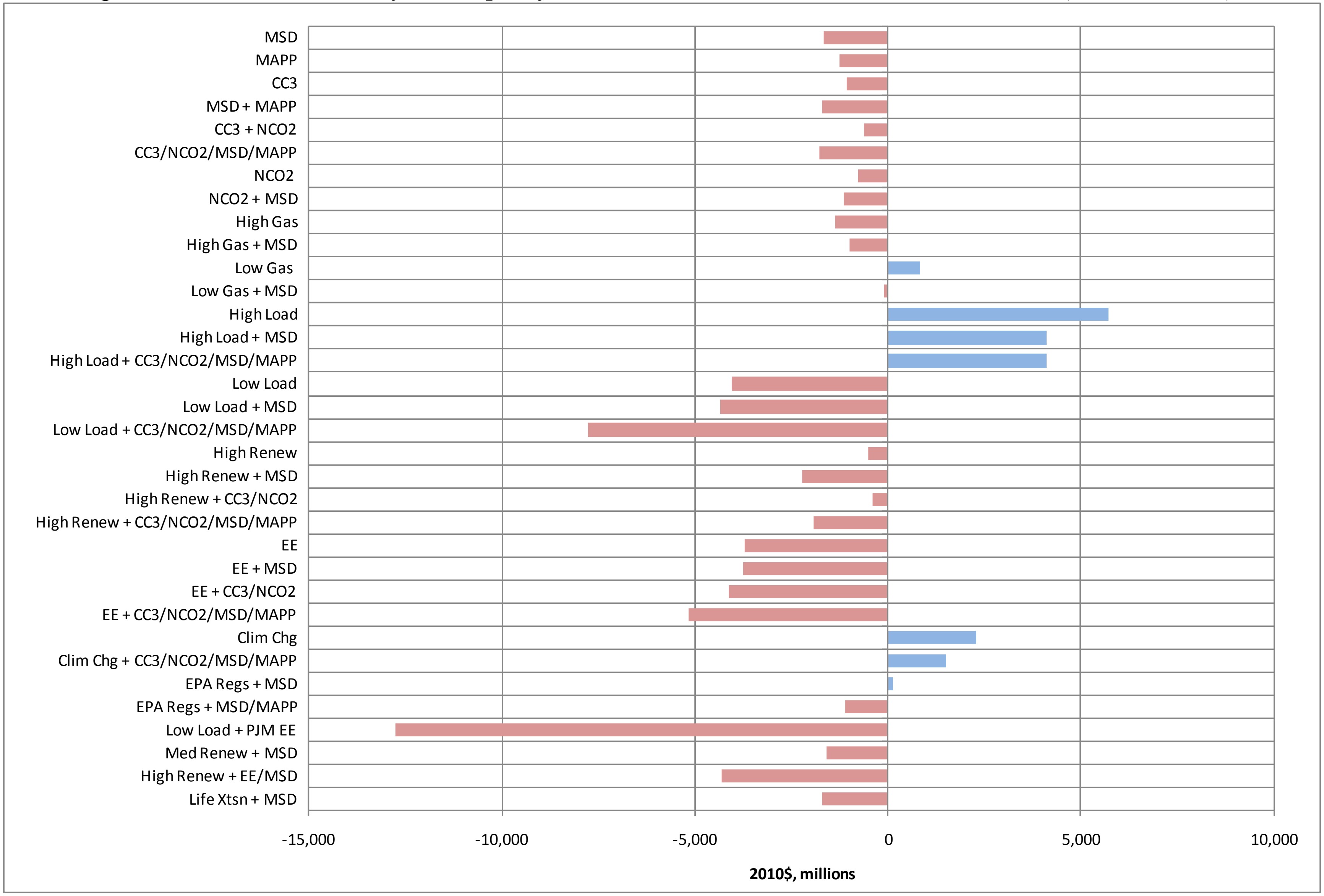
*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.35 2010 - 2030 Total Capacity Costs in Maryland (2010$, millions)*



*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

Figure 14.36 2010 - 2030 Maryland Capacity Costs—Differential from LTER Reference Case (2010$, millions)*



*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

14.11 Maryland Net Imports

Maryland is currently a net energy importer and imported 34 percent of its energy needs in 2009.[74] Since the year 2000, the State has imported at least 25 percent of its energy each year and imports averaged 26 percent between 1990 and 2009, where the annual import percentage rate ranged between 18 and 37 percent. Estimated net imports as a percentage of estimated consumption in Maryland across the scenarios are presented in Table 14.17.

Maryland's estimated net imports under the LTER Reference Case are 28 percent in 2020, the year the first generic combined cycle plant is constructed in PJM-SW and fall to 21 percent by 2030 after 2,385 MW of generic natural gas generation is added to the State. Recall that this study assumes that all generic plants constructed in the PJM-SW region are located in Maryland while new generic plants in the PJM-APS and PJM-MidE region are not assigned to any specific state. If some portion of the forecasted generic natural gas additions in PJM-APS and PJM-MidE is ultimately located in Maryland, then the figures in Table 14.17 would overstate net imports to some degree.

Since imports depend on generation in the State, the scenarios that involve higher levels of new generation capacity – both natural gas and renewable – also have lower net imports. For example, the scenarios with national carbon policy, the construction of Calvert Cliffs Unit 3, the high renewables scenarios, or high load growth have lower net imports as compared to the LTER Reference Case. Figure 14.37 graphs 2030 net imports as a percentage of total consumption in Maryland. The red bars in Figure 14.37 indicate scenarios that have negative net imports, where Maryland transforms from a net energy importer to a net energy exporter. Maryland becomes a net energy exporter in scenarios that have both Calvert Cliffs, a national carbon policy and either high renewables implementation or aggressive energy efficiency (High Renew + CC3/NCO2, High Renew + CC3/NCO2 /MSD/MAPP, EE + CC3/NCO2, and EE + CC3/NCO2/MSD/MAPP).

Upgrading the MSD transmission line facilitates imports into the PJM-SW region and hence, imports tend to be higher in the MSD scenarios. Upgrading the MSD line alone (MSD scenario) increases the percentage of energy that Maryland imports in 2030 by nine percentage points -- from 21 percent in the LTER Reference Case to 30 percent in the MSD scenario. Generally, the scenarios with the highest net import percentages in Figure 14.37 also include the MSD transmission line upgrade. Conversely, since the MAPP line results in additional gas capacity in PJM-SW, the rate of net imports tends to be lower for those scenarios that include construction of the MAPP transmission line compared to the LTER Reference Case.

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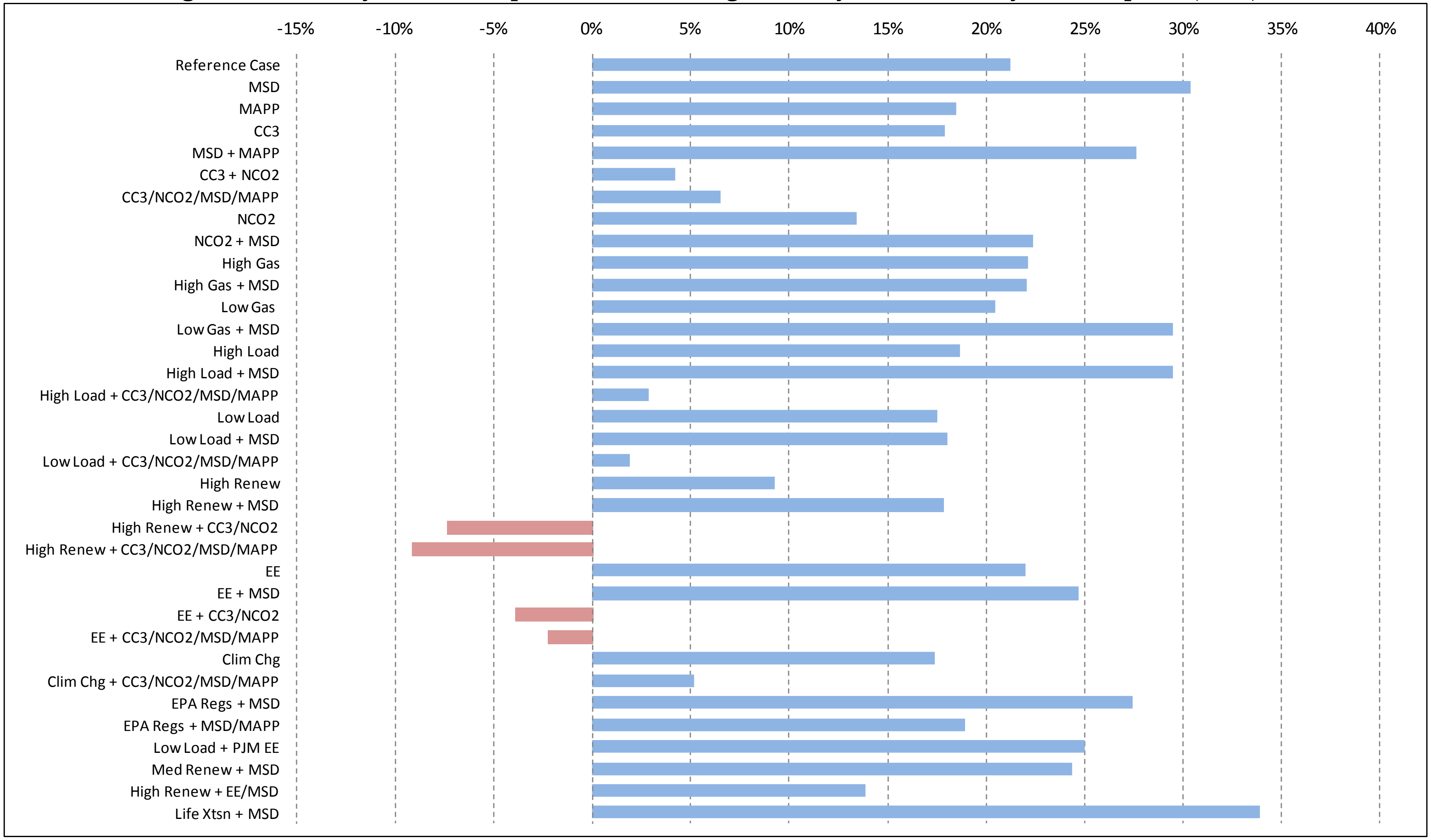
[74] EIA State Energy Spreadsheets. http://www.eia.gov/cneaf/electricity/epa/epa_sprdshts.html. Retail sales data increased by 7 percent to account for transmission and distribution and losses.

Table 14.17 Estimated Net Imports for the State of Maryland (GWh)*

Scenario	Generation		Consumption**		Net Imports		Percentage of Energy Imported	
	2020	2030	2020	2030	2020	2030	2020	2030
Reference Case	53,478	64,291	73,836	81,623	20,358	17,332	28%	21%
MSD	53,377	56,832	73,836	81,623	20,459	24,791	28%	30%
MAPP	53,816	66,533	73,836	81,623	20,020	15,090	27%	18%
CC3	62,822	66,985	73,836	81,623	11,015	14,639	15%	18%
MSD + MAPP	50,490	59,049	73,836	81,623	23,346	22,575	32%	28%
CC3 + NCO2	62,470	78,157	73,836	81,623	11,366	3,466	15%	4%
CC3/NCO2/MSD/MAPP	62,820	76,298	73,836	81,623	11,016	5,325	15%	7%
NCO2	52,960	70,648	73,836	81,623	20,876	10,975	28%	13%
NCO2 + MSD	52,933	63,380	73,836	81,623	20,904	18,244	28%	22%
High Gas	53,509	63,565	73,836	81,623	20,328	18,058	28%	22%
High Gas + MSD	53,387	63,621	73,836	81,623	20,449	18,003	28%	22%
Low Gas	53,668	64,910	73,836	81,623	20,168	16,713	27%	20%
Low Gas + MSD	50,533	57,581	73,836	81,623	23,303	24,042	32%	29%
High Load	59,238	73,450	77,714	90,304	18,476	16,854	24%	19%
High Load + MSD	55,970	63,658	77,714	90,304	21,744	26,646	28%	30%
High Load + CC3/NCO2/MSD/MAPP	72,026	87,729	77,714	90,304	5,688	2,575	7%	3%
Low Load	49,963	60,822	70,127	73,721	20,163	12,899	29%	17%
Low Load + MSD	49,903	60,432	70,127	73,721	20,224	13,290	29%	18%
Low Load + CC3/NCO2/MSD/MAPP	62,189	72,331	70,127	73,721	7,938	1,391	11%	2%
High Renew	51,153	74,077	73,836	81,623	22,683	7,547	31%	9%
High Renew + MSD	51,022	67,104	73,836	81,623	22,814	14,520	31%	18%
High Renew + CC3/NCO2	63,035	87,626	73,836	81,623	10,801	-6,002	15%	-7%
High Renew + CC3/NCO2/MSD/MAPP	63,344	89,099	73,836	81,623	10,492	-7,476	14%	-9%
EE	50,616	58,407	67,067	74,854	16,451	16,448	25%	22%
EE + MSD	50,550	56,430	67,067	74,854	16,517	18,424	25%	25%
EE + CC3/NCO2	62,525	77,784	67,067	74,854	4,542	-2,930	7%	-4%
EE + CC3/NCO2/MSD/MAPP	63,008	76,551	67,067	74,854	4,059	-1,697	6%	-2%
Clim Chg	56,250	68,298	74,117	82,701	17,867	14,403	24%	17%
Clim Chg + CC3/NCO2/MSD/MAPP	68,423	78,434	74,117	82,701	5,695	4,267	8%	5%
EPA Regs + MSD	54,558	59,227	73,836	81,623	19,278	22,396	26%	27%
EPA Regs + MSD/MAPP	55,089	66,191	73,836	81,623	18,747	15,432	25%	19%
Low Load + PJM EE	49,542	52,721	66,757	70,309	17,216	17,588	26%	25%
Med Renew + MSD	53,104	61,716	73,836	81,623	20,732	19,907	28%	24%
High Renew + EE/MSD	51,153	64,485	67,067	74,854	15,914	10,369	24%	14%
Life Xtsn + MSD	53,358	53,942	73,836	81,623	20,478	27,682	28%	34%

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.
**Maryland consumption estimates are increased by 7 percent to account for transmission and distribution losses.

Figure 14.37 Maryland Net Imports as a Percentage of Maryland Electricity Consumption (2030)*



*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

14.12 Generic Capacity Additions

The infrastructure, load, fuel price, and policy scenarios presented in the LTER have significant implications for the total amount of capacity built in both the state of Maryland and in PJM as a whole. The Ventyx model automatically builds the least-cost generation available, which in all cases is natural gas, in order to maintain reliability within PJM. The Ventyx model also builds that generic capacity in the most economic location possible, subject to transmission system constraints. The LTER Reference Case results indicate that by 2030, approximately 30 GW of new generic gas capacity will be constructed in PJM and 2,385 MW will be constructed in PJM-SW. The results of the alternative scenarios indicate that the level of new generic capacity in both PJM as a whole and within the PJM-SW zone depends most heavily on load growth. A national carbon policy and EPA regulations also prompt the construction of more generic capacity, but to a lesser extent than growth in load.

Table 14.18 summarizes the generic capacity additions in PJM as a whole and in PJM-SW, including the total amount of generic gas capacity constructed and the first year that new capacity is constructed.[75] The high and low load growth scenarios exhibit the greatest change from the LTER Reference Case as far as generic capacity additions are concerned. In most of the scenarios, the total generic capacity constructed in PJM ranges between 27 and 35 GW, compared to 30 GW in the LTER Reference case. However, only 8 GW of capacity, 73 percent lower than the LTER Reference Case, is constructed under the low load growth scenario because PJM's existing generation fleet is sufficient to serve loads until 2025. The need for new capacity declines even further in the low load plus PJM-wide energy efficiency scenario, where only 2,385 MW of new generic capacity is constructed, which is approximately 92 percent less than the LTER Reference Case. High load growth results in an additional 21.7 GW of new generic gas capacity in PJM as a whole relative to the LTER Reference Case. The 72 percent increase in generic capacity in PJM under the high load scenario relative to the LTER Reference Case is essentially the mirror image of the low load scenario, which saw a 73 percent decrease in capacity relative to the LTER Reference case.

Climate change and a national carbon policy increase the need for generic natural gas capacity in PJM by approximately 9 GW and 7 GW, respectively. The combination of climate change, a national carbon policy, Calvert Cliffs 3, and the MAPP and MSD transmission projects causes the greatest investment in generic capacity, requiring an additional 14.7 GW relative to the LTER Reference Case. High and low gas prices are shown not have a significant impact on the level of new generic capacity constructed in PJM because load growth in both the high and low gas price scenarios is the same as under the LTER Reference Case. Thus, new capacity must be constructed to satisfy load growth whether natural gas prices are high or low. However,

[75] The analogous data for the Supplemental Responsive Scenarios is shown in Appendix L, Table L-18.

natural gas prices do affect the type of generic natural gas unit constructed because more CTs are constructed when natural gas prices are low.

Table 14.18 Generic Natural Gas Capacity Additions by 2030*

	PJM Total			PJM-SW		
Scenario	**Total Capacity by 2030 (MW)**	**Change from RC (MW)**	**Year First Plant Built**	**Total Capacity by 2030 (MW)**	**Change from RC (MW)**	**Year First Plant Built**
Reference Case	30,101	0	2018	2,385	0	2020
MSD	30,145	45	2018	1,431	(954)	2020
MAPP	30,101	0	2018	2,385	0	2020
CC3	28,496	(1,605)	2018	954	(1,431)	2022
MSD + MAPP	30,016	(84)	2018	1,431	(954)	2021
CC3 + NCO2	35,273	5,172	2018	2,862	477	2022
CC3/NCO2/MSD/MAPP	35,661	5,560	2018	2,385	0	2022
NCO2	37,181	7,080	2018	3,339	954	2020
NCO2 + MSD	37,355	7,254	2018	2,385	0	2019
High Gas	29,927	(174)	2018	2,385	0	2020
High Gas + MSD	29,360	(740)	2018	2,862	477	2020
Low Gas	29,335	(765)	2019	2,907	522	2020
Low Gas + MSD	29,599	(502)	2019	1,605	(780)	2021
High Load	51,839	21,738	2015	3,816	1,431	2017
High Load + MSD	52,932	22,831	2015	3,081	696	2017
High Load + CC3/NCO2/MSD/MAPP	57,622	27,522	2015	4,293	1,908	2017
Low Load	8,109	(21,992)	2025	1,908	(477)	2026
Low Load + MSD	8,586	(21,515)	2025	1,908	(477)	2027
Low Load + CC3/NCO2/MSD/MAPP	15,443	(14,658)	2025	1,908	(477)	2027
High Renew	28,496	(1,605)	2018	1,908	(477)	2021
High Renew + MSD	28,933	(1,168)	2018	954	(1,431)	2021
High Renew + CC3/NCO2	33,753	3,652	2019	2,385	0	2023
High Renew + CC3/NCO2/MSD/MAPP	34,100	4,000	2018	2,385	0	2023
EE	28,193	(1,908)	2019	1,431	(954)	2022
EE + MSD	27,845	(2,256)	2019	1,431	(954)	2022
EE + CC3/NCO2	33,971	3,871	2021	2,862	477	2023
EE + CC3/NCO2/MSD/MAPP	33,753	3,652	2021	2,385	0	2022
Clim Chg	39,352	9,252	2016	3,339	954	2019
Clim Chg + CC3/NCO2/MSD/MAPP	44,828	14,727	2016	2,862	477	2019
EPA Regs + MSD	34,011	3,910	2017	2,604	219	2019
EPA Regs + MSD/MAPP	33,966	3,866	2017	2,862	477	2019
Low Load + PJM EE	2,385	(27,716)	2029	477	(1,908)	2030
Med Renew + MSD	29,494	(606)	2018	954	(1,431)	2021
High Renew + EE/MSD	26,588	(3,513)	2020	477	(1,908)	2027
Life Xtsn + MSD	27,239	(2,862)	2018	954	(1,431)	2020

*The analogous projections for the Supplemental Responsive Scenarios are included in Appendix L.

The factors that affect generic capacity construction in PJM as a whole have similar impacts on construction in PJM-SW. In PJM-SW, high load growth results in 1,431 MW (three generic CCs) of additional generic capacity compared to the LTER Reference Case. Similarly, the PJM-SW zone only constructs 1,908 MW of capacity in the low load case, which is 477 MW (20 percent) less than in the LTER Reference Case. This generic capacity reduction relative to the LTER Reference Case is more moderate in PJM-SW than it is in PJM as a whole because Maryland is a net importer, and is thus forced to build its own capacity when load growth is low because it cannot import from neighboring zones, which also experience low load growth. The MSD transmission project reduces the amount of new generic capacity in PJM-SW by almost one GW because it enables the zone to import more energy from neighboring zones rather than build locally.

The High Renewables scenario involves approximately 4 GW of additional renewable capacity in Maryland distributed across PJM-SW, PJM-APS, and PJM-MidE. However, the PJM-SW region only builds one fewer CC unit (477 MW). This is largely because the additional renewable capacity is located in the PJM-MidE and PJM-APS zones. Under the High Renewables scenario, PJM as a whole builds 1,605 fewer MW of generic capacity, which is less than the 4 GW of additional renewable capacity. Adding an additional MW of renewable capacity does not reduce the need for additional generic natural gas capacity on a one-for-one basis. The renewable/conventional capacity tradeoff is less than one-to-one because renewable capacity is intermittent, and thus contributes less to meeting the PJM aggregate peak demand.

The timing of the generic capacity construction is also important because it indicates when PJM has grown out of the excess capacity that currently exists in PJM. In the LTER Reference Case, the first plant is not constructed until 2018 in PJM, and until 2020 in PJM-SW. However, under high load growth, the need for new capacity occurs three years earlier in PJM (2015). Similarly, under high load growth assumptions, the PJM-SW region needs its first generic natural gas plant in 2017 rather than in 2020. Low load growth delays the need for new capacity in PJM by seven years, from 2018 in the LTER Reference Case to 2025 in the low load scenario. Under the low load assumptions, the PJM-SW region does not need any new capacity until 2026, six years later than the LTER Reference Case. EPA regulations, a national carbon policy, and climate change also accelerate the need for new capacity in PJM as a whole.

In PJM-SW, a higher penetration of renewables delays the first generic natural gas plant build to 2021, one year later than the LTER Reference Case. A third unit at Calvert Cliffs pushes back the need for a new generic natural gas capacity in PJM-SW by two years, as does aggressive energy efficiency savings in the State and the combination of a national carbon policy and construction of Calvert Cliffs 3 unit. The need for new capacity is most delayed in the low load plus PJM-wide energy efficiency scenario, where a new plant is not needed in PJM-SW until 2030.[76]

14.13 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 14.19 displays the estimated amount of land required to accommodate electricity generation for four generation types.

Table 14.19 Land Use 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 14.19, nuclear and natural gas power plants typically require significantly less land area than wind and solar generating facilities. 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 172 projects. The wide range reflects differences in size of the turbines used, the nature of the terrain, and differences in the

[76] Appendix L shows resuts for supplemental scenarios developed in response to comments received on the draft final LTER and incorporate assumptions that affect the initial year of new power plant requirements in Maryland. Please see Appendix L for a discussion of this issue with respect to the supplemental responsive scenarios.

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 are expected to be higher. For wind power generation projects where the land is not being used for secondary activities, 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 technologies 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

On-shore 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.[77] 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.[78] However, as on-shore wind facilities utilize a significant amount of land, they have the potential to fragment the ecological habitats of rare, threatened, and endangered species. The construction and maintenance of wind facilities can alter ecosystem structure, which is especially a concern in areas that are difficult to restore, such as deserts and forests. Concerns also exist regarding bird and bat mortality due to collisions with turbines, although recent European studies suggest that birds learn to fly around the turbines and avoid collisions. Finally, appropriate measures must be taken during construction to minimize erosion and control sediment runoff into nearby waterways.

Although an off-shore 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 off-shore 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,

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[77] 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

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

avian and marine life, and tourism in beach communities in Maryland.[79] 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.

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.[80] 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.[81] Solar photovoltaic typically requires more land than solar thermal, but both types of solar generation generally 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 capacity.[82] 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.

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[79] 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

[80] 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

[81] National Renewable Energy Laboratory, as sited in Gilbert Cohen, Solargenix Energy, Solar Energy Technologies Systems Symposium CD, Albuquerque, 2003.

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

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.[83] Another study estimated the land use requirements for natural gas to be as high as 2 acres per MW.[84]

Summary

The approximate amount of land area needed to build new capacity in Maryland based on the means in Table 14.20, are shown in Figure 14.38.[85] 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.[86] 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 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 used 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 14.38 shows that the High Renewables scenarios require approximately eight times the area required under the LTER Reference Case. The Medium Renewables scenario requires approximately four times the area required under the LTER Reference Case. This difference is largely attributable to on-shore wind development under the High Renewables and Medium Renewables scenarios. It should be noted that land used for on-shore wind development

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[83] 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

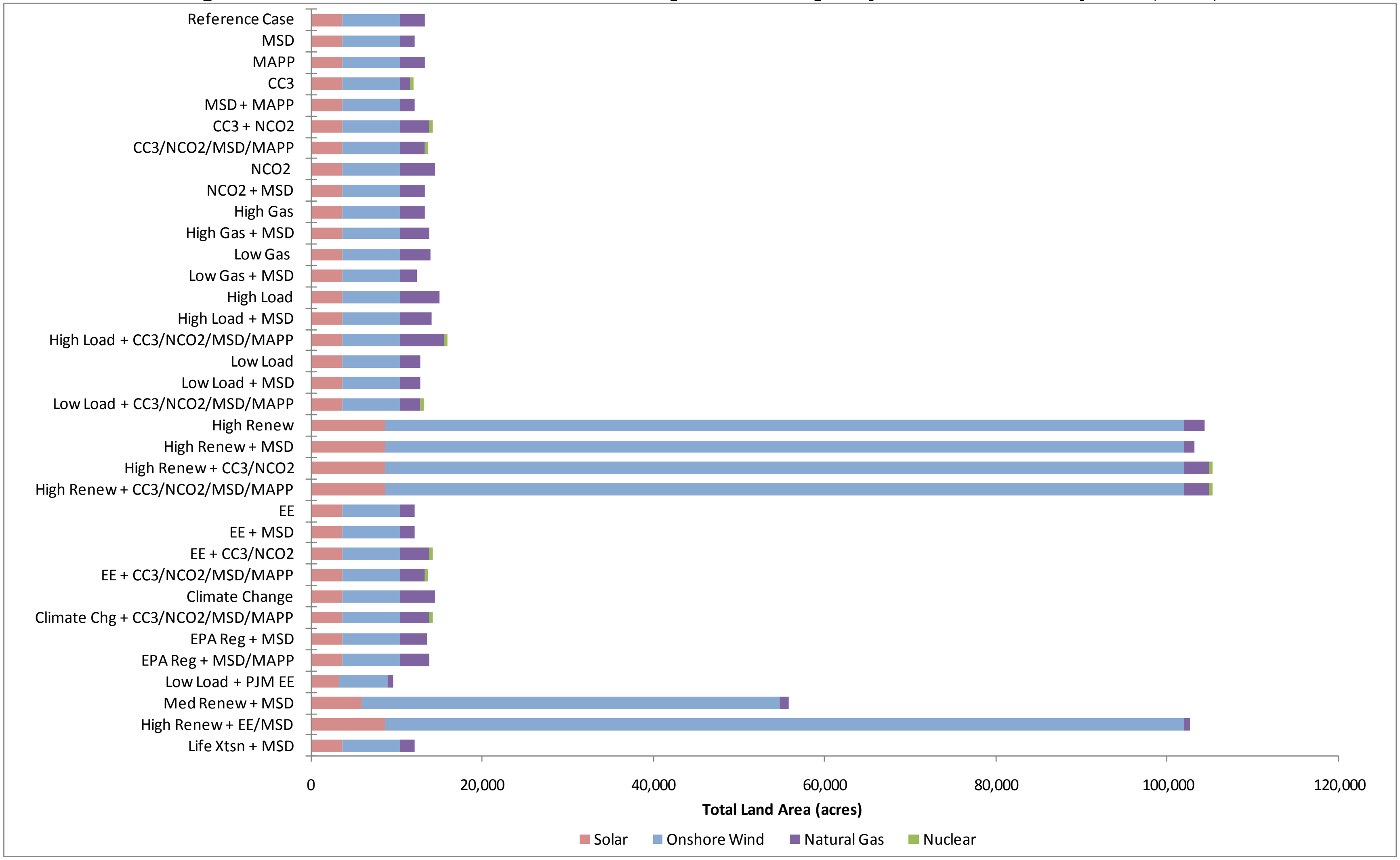
[84] David Kay, *Land Use and Energy*, Cornell University, November 15, 2010, as cited in Paula Bernstein, *Alternative Energy: Facts, Statistics, and Issues*, 2001.

[85] The analogous data for the Supplemental Responsive Scenarios are presented in Appendix L, Table L-20.

[86] 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.

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 most of the other scenarios. The range of land use requirements among those scenarios is approximately 12,000 to 15,000 acres, with the exception of two scenarios. The Low Load and PJM-wide Energy Efficiency scenario requires less than 10,000 acres, and the High Load scenario that includes the implementation of national carbon legislation requires about 16,000 acres.

Figure 14.38 Total Estimated Land Area Required for Capacity Additions in Maryland (acres)



*The land use requirements for the High Renewables and Medium Renewables scenarios shown in this figure 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.

14.14 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 the production costs of each scenario while others may be more concerned with the environmental implications. 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 an unambiguous "best" scenario and as such this section presents rankings of several key metrics rather than a single ranking across scenarios.

Table 14.20 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 highest total production costs that are ranked in the top third (66^{th} through 100^{th} percentile) amongst the scenarios are denoted with a fully-shaded circle. The scenarios with production costs ranked in the middle third (33^{rd} through 66^{th} percentile) are denoted with a half-shaded circle. Finally, the scenarios with lowest total production costs that are ranked in the bottom third (0 through 33^{rd} 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 among 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 14.20 and Figure 14.27 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 (relative to the LTER Reference Case) by $226 billion and $102 billion, respectively.

Table 14.20 PJM-Wide Cost and Revenue by Scenario

	Total Production Costs	Wholesale Energy Revenues	Capacity Revenues
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	●	●	●
EPA Reg + MSD	◑	◑	●
EPA Reg + MSD/MAPP	◑	◑	●
Low Load + PJM EE	○	○	○
Med Renew + MSD	○	○	◑
High Renew + EE/MSD	○	○	○
Life Xtsn + MSD	◑	○	○
Early Natural Gas Plant	◑	○	●
Combined Events	○	○	●
EPA/MSD/AR1	◑	◑	●
EPA/MSD/AR2	◑	◑	●

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

The second column of Table 14.20 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 Gas scenario to $1.371 trillion 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 14.20 also ranks capacity market revenues earned by PJM generators over the study period (in 2010 dollars). Capacity market revenues are $175 billion in the LTER Reference Case and most of the alternative scenarios have total capacity market revenues in the $160-$180 billion range. Load growth is an important driver of capacity market revenues. The three high load growth scenarios have capacity market revenues in excess of $245 billion. Conversely, the four low load growth scenarios have capacity market revenues under $120 billion. The highest level of capacity revenues occurs under the Combined Events scenario, in which PJM generators earn over $300 billion in capacity market revenues.

Table 14.21 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. In general, the total emissions of each pollutant do not vary widely across scenarios. Emissions levels in most scenarios are within 5 percent of the LTER Reference Case; however some scenarios result in significant emissions reductions relative to the LTER Reference Case. The assumptions regarding load levels and the proposed EPA regulations induce the largest shifts from LTER Reference Case emissions levels.

Under the Low Load and PJM-wide Energy Efficiency scenario, total SO_2 emissions are about 8 percent lower than in the LTER Reference Case. In the Combined Events scenario, total SO_2 emissions are about 21 percent lower than in the LTER Reference Case, resulting from the combination of a much newer and cleaner PJM fleet along with the proposed EPA regulations regarding SO_2 emissions. In the EPA/MSD/AR2 scenario, total NO_x emissions levels are about 32 percent lower than in the LTER Reference Case, also resulting from the proposed EPA regulations regarding NO_x emissions and a much newer and cleaner fleet of PJM power plants. The scenarios that include EPA regulations without additional plant retirements, however, result in total NO_x emissions that are only about 11 percent lower than in the LTER Reference Case. In the Low Load + CC3/NCO2/MSD/MAPP scenario, total CO_2 emissions levels are about 11 percent lower than in the LTER Reference Case. Note that the highest emissions levels, relative to the LTER Reference Case, are observed in the High Load scenario. Under the high load assumptions, total CO_2 emissions are about 5 percent higher than in the LTER Reference Case.

Table 14.21 PJM-Wide Summary Emissions by Scenario

	Total NOx Emissions	Total SO_2 Emissions	Total CO_2 Emissions
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	◑	◑	◑
EPA Reg + MSD	○	◑	◑
EPA Reg + MSD/MAPP	○	◑	◑
Low Load + PJM EE	○	○	○
Med Renew + MSD	◑	◑	●
High Renew + EE/MSD	◑	◑	◑
Life Xtsn + MSD	●	●	●
Early Natural Gas Plant	●	●	●
Combined Events	○	○	○
EPA/MSD/AR1	○	○	◑
EPA/MSD/AR2	○	○	○
● = top third	◑ = middle third	○ = bottom third	

Table 14.22 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 14.22 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 less than 2.5 GW is built in the Low Load plus PJM-wide Energy Efficiency 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 high 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. The Combined Events scenario induces the highest level of generic capacity additions, resulting in 61.6 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 14.22 PJM-Wide Summary Diversity and Capacity Additions by Scenario

	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	●	●
EPA Reg + MSD	◑	◑
EPA Reg + MSD/MAPP	◑	◑
Low Load + PJM EE	○	○
Med Renew + MSD	◑	◑
High Renew + EE/MSD	◑	○
Life Xtsn + MSD	◑	○
Early Natural Gas Plant	◑	◑
Combined Events	●	●
EPA/MSD/AR1	◑	●
EPA/MSD/AR2	●	●

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

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

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A copy of the full report is provided on the CD below. To obtain additional copies of the Long-term Electricity Report (LTER), contact PPRP at (410) 260-8660 (toll free number in Maryland 1-877-620-8DNR x8660). The LTER can be downloaded by visiting the DNR PPRP website at: http://esm.versar.com/pprp/pprphome.htm.