FINANCIAL RISK ANALYSIS OF THE RETURN TO RATE BASE REGULATION

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Glossary

ACI	Activated Carbon Injection
ACP	Alternative Compliance Payment
AEP	American Electric Power
ALJ	Administrative Law Judge
AP	Appalachian Power
APS	Allegheny Power System
Bbl	Barrel
BGE	Baltimore Gas & Electric
bp	Basis Points
BRAC	Base Realignment and Closure
BTA	Best Technology Available
C&I	Commercial & Industrial
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CapEx	Capital Expenditure
CETL	Capacity Emergency Transfer Limit
CETO	Capacity Emergency Transfer Objective
CO_2	Carbon Dioxide
Commission	Maryland Public Service Commission
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity
CT	Combustion Turbine
DAM	Day-Ahead Market
DCF	Discounted Cash Flow
DOE	Department of Energy
DOM	Dominion
DPL	Delmarva Power & Light
DR	Demand Response
DSM	Demand-Side Management
DVP	Dominion Virginia Power
EAS	Energy & Ancillary Services
EBITDA	Earnings Before Income Taxes, Depreciation and Amortization
EIA	Energy Information Administration
EMAAC	Eastern Mid-Atlantic Area Council
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EV	Expected Value
EVA	Economic Value Added
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FMV	Fair Market Value
G&A	General & Administrative
GDP	Gross Domestic Product
GHG	Greenhouse Gases
GMP	Gross Metropolitan Product
GO	General Obligation
GT	Gas Turbine
HAA	Healthy Air Act
IEO	International Energy Outlook
IMM	Independent Market Monitor
IOU	Investor-Owned Utility
IRM	Installed Reserve Margin
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
kW	Kilowatt
LAI	Levitan & Associates, Inc.

LC	Letter of Credit
LDA	Local Deliverability Area
LIPA	Long Island Power Authority
LMP	Locational Marginal Price
MAAC	Mid-Atlantic Area Council
MACT	Maximum Achievable Control Technology
MDE	Maryland Department of Environment
MdTA	Maryland Transportation Authority
MMBtu	Million British Thermal Units
MMU	Market Monitoring Unit
MW	Megawatt
NBER	National Bureau of Economic Research
NERC	North American Electric Reliability Corporation
NO_x	Nitrogen Oxides
NRC	Nuclear Regulatory Commission
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
NYPA	New York Power Authority
O&M	Operation and Maintenance
OGPR	Oil-to-Gas Price Ratio
PATH	Potomac Appalachian Transmission Highline
PDF	Probability Density Function
Pepco	Potomac Electric Power Company
PHI	Pepco Holdings, Inc.
PJM	PJM Interconnection
PPA	Power Purchase Agreement
PPRP	Power Plant Research Program
PS	Public Service Electric & Gas
PSNH	Public Service Company of New Hampshire
RGGI	Regional Greenhouse Gas Initiative
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTM	Real-Time Market
RTO	Regional Transmission Organization
SCC	State Corporation Commission
SCR	Selective Catalytic Reduction
SMECO	Southern Maryland Electric Cooperative
SO_2	Sulfur Dioxide
SOS	Standard Offer Service
SWMAAC	Southwest Mid-Atlantic Area Council
TARP	Troubled Assets Relief Program
TrAIL	Trans-Allegheny Interstate Line
TrAILCo	Trans-Allegheny Interstate Line Company
TVaR	Tail Value-at-Risk
TVaR95	Tail Value-at-Risk (95% confidence)
UCAP	Unforced Capacity
VaR	Value-at-Risk
VaR95	Value-at-Risk (95% confidence)
WTI	West Texas Intermediate

INTRODUCTION

At the General Assembly's request, this report provides a more focused, in-depth analysis of the costs, benefits, and risks that electricity customers would incur if Maryland's investor-owned utilities (IOUs) or a State-owned power authority (Authority) were to reacquire existing generation assets and recover their costs of service under traditional regulation. Under the Maryland Public Service Commission's (Commission's) direction, Levitan & Associates, Inc. (LAI) and Kaye Scholer LLP have conducted what amounts to a case study of the possible acquisition of the existing Maryland-based generation fleet owned by Mirant. This analysis includes not only an updated assessment of the impact of the recent economic downturn but considers potential developments that could affect the desirability of IOU or Authority ownership of Maryland's existing generation assets. This review is designed to give policy makers a factual, quantitative basis for making judgments about the direction of Maryland's electricity future and the extent to which generation facilities should be returned to regulation.

This report builds on our previous analyses for the Commission. In accordance with Chapter 549, Maryland Laws of 2007, the Commission was required to evaluate the status of restructuring in Maryland and to assess options for re-regulation. Under the Commission's direction, LAI and Kaye Scholer undertook a study of Maryland's long-range energy options. The results of the first phase of the study, *Analysis of Options for Maryland's Energy Future* (Interim Report), were published on November 30, 2007. The resource options evaluated in the Interim Report included new gas-fired combined-cycle plants, the addition of a supercritical pulverized coal plant, a new nuclear reactor unit at Calvert Cliffs, long-term power purchase agreements (PPAs) between Maryland's IOUs and generation developers, fulfillment of Governor O'Malley's EmPOWER Maryland "15 by 15" conservation and load management initiative, addition of a major new "backbone" transmission project, and expansion of the in-state wind turbine fleet, both onshore and offshore.

The most attractive generation, demand-side management (DSM), and long-term contracting options were further evaluated in the *Analysis of Options for Maryland's Energy Future* published on December 1, 2008 (Task 3 Report). In the Task 3 Report, we focused on the options which are within the authority of the General Assembly and/or the Commission to effectuate through legislative action, rulemaking, and/or policy decision. We also quantified the potential benefits to Maryland's ratepayers associated with a return to rate base regulation. LAI postulated two transaction structures: first, IOU ownership using taxable debt and equity capital to finance the acquisition of the Mirant fleet in Maryland; and, second, the formation of a new state power Authority that would issue taxable revenue bonds for 100% of the Authority's capital requirements. Under both transaction structures, we have assumed that the Commission would have the statutory authority to allow for the pass-through of all reasonably incurred fixed and variable costs, including capital charges, arising from the return to rate base regulation, irrespective of changes in market prices, environmental regulation, and technology. As a proxy for IOU ownership, the potential savings to the Potomac Electric Power Co.'s (Pepco's) ratepayers relative to the business-as-usual case was modeled on a deterministic basis over a 20-year valuation period. For simplicity, we modeled the potential savings as accruing to Pepco's ratepayers, but the Commission could reasonably choose to allocate those savings among Maryland's ratepayers in some other fashion. A deterministic analysis identified a single expected outcome based on a fixed set of parameters. In contrast, probabilistic analysis produces an expected value based on random sampling of various uncertainty variables.

The present value of the net benefits to ratepayers was referred to as the Economic Value Added (EVA): the higher the EVA, the higher the net economic benefit in relation to the status quo, *i.e.*, the PJM Interconnection's (PJM's) wholesale market design.

In the Task 3 Report, LAI derived the Fair Market Value (FMV) of the Mirant fleet. Using traditional discounted cash flow (DCF) analysis – an approach used by appraisers and investors in utility assets – the FMV was determined to be $6.3 billion. Under most likely assumptions about market structure, regulation, and fuel prices available in the summer of 2008, the resultant EVA ranged from $1.65 billion to $4.10 billion under IOU and Authority ownership, respectively. Limited sensitivity analysis was also conducted. We tested the sensitivity of the financial results under much higher and lower commodity prices, as well as under the more aggressive backbone transmission buildout assumptions approved by PJM's Board in 2007. The sensitivity analysis produced results that ranged from a low of about negative $1.0 billion (Low Fuel Prices / Pepco Ownership) to a high of $8.8 billion (High Fuel Prices / Authority Ownership). Because there are many other uncertainty factors and risks besides fuel prices and transmission infrastructure additions, it was not possible in the Task 3 Report to identify the relative likelihood of good versus bad financial outcomes in relation to the expected EVA outcome.

In January 2009, the Commission asked LAI and Kaye Scholer to conduct a much more rigorous analysis of the return of the Mirant fleet to rate base regulation, including a quantification of the risk factors that had previously been identified only qualitatively. The economics of acquiring the Constellation fleet or other generation plants in Maryland is not part of this scope of work. While the prior study offered sound guidance on policy initiatives, the scope of work was not centered on a return to rate base regulation. In this study, the scope of work is exclusively centered on rate base regulation, thereby incorporating the additional rigor to support a major policy decision or legislative action. Building upon the deterministic valuation framework, we have applied more advanced modeling techniques in order to produce probabilistic, risk-adjusted EVAs under both the IOU and Authority ownership structures. The spectrum of good versus bad financial outcomes and the relative chance of occurrence are reported in this study. The distribution of EVAs allows for the use of statistical measures of risk that address both "downside" (worse than expected) and "upside" (positive earnings surprises) outcomes.

In many instances, LAI has also refined input parameters to the cash flows based on more extensive due diligence about operating costs, performance, transaction costs, and environmental compliance, among other things. Finally, we have updated key factor inputs in order to account for significant changes in economic, policy, regulatory and planning criteria. Changes to key factor inputs are limited to those variables that have a direct bearing on the FMV of the Mirant fleet or the spectrum of risks and rewards.

Key factor inputs have been changed materially to account for:

- ❒ The $100 per barrel decline in oil prices and different long-term expectations about premium fossil fuel prices since oil and gas prices peaked in July 2008.

- ❐ The emerging policies of the Obama Administration on climate change and potential federal initiatives to control greenhouse gases (GHG).
- ❐ The impact of the global credit crisis on electricity demand in PJM and Maryland, in particular.
- ❐ The anticipated commercialization of the Trans-Allegheny Interstate Line (TrAIL) in 2011 rather than 2014.
- ❐ Changes to PJM reliability criteria and planning parameters affecting capacity prices under PJM's Reliability Pricing Model (RPM).

Highlights of the financial analysis follow in the Executive Summary.

In Section 1, we provide more detail about the regulatory, economic, and market developments since publication of the Task 3 Report that affect our current analysis. In Section 2, we present more comprehensive background on the generation plants owned by Mirant in Maryland. In Section 3, we describe the transaction structure and financial assumptions used to derive the enterprise value of the Mirant fleet in Maryland under FMV. In Section 4, we explain the analytic foundation of the seven scenarios tested in LAI's production simulation model as well as the independent variables used in the probability analysis. The updated FMV analysis is presented in Section 5. In Section 6, we set forth the basis for the methodology and input factors for the probabilistic analysis. Financial results are presented in Section 7.

Finally, in Section 8, we present a more extensive analysis on an array of other risk factors that have not been quantified in the derivation of EVAs. Emphasis is placed on the prospect of resulting harm to the wholesale and retail markets in Maryland and PJM following re-regulation of the Mirant fleet.

EXECUTIVE SUMMARY

Key Findings

From the vantage point of Maryland's ratepayers, there is no way to know with even reasonable certainty how re-regulation of the Mirant generation fleet will turn out. The decision to return to rate base regulation in Maryland is a complex problem, the central controversial aspects of which are well-suited to formal probability theory and relatively standard quantitative analysis techniques. Given the financial stakes associated with re-regulation, however, it is not sufficient only to quantify the *expected* economic benefits ascribable to the acquisition of the Mirant fleet. Informed decision-making requires consideration of the possibility of other potential economic outcomes.

In this study, we have applied a rigorous analytical technique to measure both the upside reward and the downside risk relative to wholesale power costs otherwise incurred under the existing PJM market design. In general, we have used neutral estimates of probabilities, thereby avoiding any conscious skew in the results, either toward the upside reward or downside risk. In order to reflect more current economic conditions, we have also updated and refined other components of total project cash flows pertaining to plant operating performance and many financial variables that have changed even in the short period since the Task 3 Report.

Key results of this analysis follow:

- ❒ Using traditional DCF analysis, the FMV of the Mirant fleet is approximately $5.1 billion, or $1,080/kW. An enterprise value of $5.1 billion reflects a $1.2 billion reduction from the FMV presented in the Task 3 Report, primarily due to the reduced energy profits associated with the sale of energy from the coal plants.

- ❒ **Under IOU ownership**, re-regulation of the Mirant fleet exposes ratepayers to a broad dispersion of potential economic outcomes. The long-term financial benefits associated with rate base regulation are hypersensitive to volatile oil and natural gas prices, as well as evolving federal approaches to controlling GHG emissions. There are other uncertainty variables that do <u>not</u> bear directly on energy prices in Maryland, but do in fact impact the spectrum of benefits and costs from a ratepayer's standpoint. When EVA is expressed in simple terms on a deterministic basis, projected ratepayer benefits equal $1.75 billion. The timing pattern of the benefits on a risk-adjusted basis is heavily back-end loaded, meaning retail customers can reasonably expect to pay significantly more for many years at the beginning under rate base regulation relative to the existing PJM market design. When the EVA is expressed on a probabilistic basis, however, the expected EVA decreases materially to negative $0.003 billion, *i.e.*, essentially zero. This decrease of $1.75 billion in relation to the deterministic calculation of EVA is due to the combined impact of key uncertainty variables and risks. Under IOU ownership, one-half of the potential economic outcomes are positive and one-half are negative – in effect, a flip of the coin in terms of "good" versus "bad" outcomes. Across the spectrum of bad outcomes, the expected loss is $1.30 billion. There is a 1-in-20 chance of occurrence that the return to rate base regulation will *cost* ratepayers more than $2.47 billion rather than yield *any* benefits. On the positive side there is also a 1-in-20 chance of occurrence that ratepayers experience an earnings surprise larger than \$2.84 billion. Among the worst of the negative outcomes, the expected value of the loss is \$3.11 billion, a relatively low likelihood outcome.

- **Under Authority ownership**, the potential re-regulation of the Mirant fleet decidedly limits adverse ratepayer exposure. The combination of the State of Maryland's conservative debt strategy, coupled with the anticipated strength of the regulatory covenant to pass along all costs, suggests a high likelihood of a positive outcome. Assuming the issuance of revenue bonds at an average interest rate of 5.6% for 100% of the Authority's capital requirements, the EVA is \$3.59 billion on a deterministic basis. When EVA is expressed on a probabilistic basis, EVA decreases to \$1.82 billion – still a strongly positive outcome ascribable to rate base regulation. The annual net benefit on a risk-adjusted basis is deep-in-the-black, almost from the beginning of the 20-year valuation period. Under Authority ownership, ratepayers can reasonably expect to pay significantly less than under the existing PJM market design. Notably, under Authority ownership only 13% of the potential economic outcomes are negative values. Across the spectrum of bad outcomes, the expected loss is \$0.66 billion. Under Authority ownership there is a 1-in-20 chance of occurrence that losses exceed \$0.60 billion, but on the positive side there is the same chance of savings worth more than \$4.6 billion. Among the worst of the bad outcomes associated with Authority ownership, the expected value of the loss is \$1.2 billion, also a low likelihood outcome.

- The broad dispersion of financial results under either IOU or Authority ownership is largely explained by the impact of uncertain premium fossil fuel prices and federal GHG policy about the timing and structure of a federal cap-and-trade program for carbon dioxide (CO_2) allowances. All forecasts of oil and natural gas prices over the long term are subject to large measurement error, which is why we have randomly sampled across a large bandwidth of potential values. The price of CO_2 allowances over the forecast period is likewise subject to large measurement error. In producing the dispersion of financial results, we have accounted for other financial and operational "second-tier" independent variables, including future environmental compliance costs, transaction costs, transition costs related to organizational staffing, cost of capital, and long-term operating problems that may arise from time to time in operating coal plants that are forty or fifty years old.

- Rejection of the PJM wholesale market design in favor of the return to rate base regulation of the Mirant fleet will not necessarily impair the *wholesale market* administered by PJM elsewhere in Maryland or across the market area. We believe that the return to rate base regulation of the Mirant assets in Maryland would not unleash a contagious, anti-competitive reaction at the wholesale level across PJM. We note, however, the high likelihood that either the IOU or the Authority would need to "anchor" future resource additions in the Southwest Mid-Atlantic Area Council (SWMAAC) either by owning or purchasing under long-term agreement both conventional and renewable resource additions. In light of the recent credit implosion, this reliance on a utility anchor – at least in the foreseeable future – appears inescapable, regardless of the State's decision about re-regulation.

- The return to rate base regulation at the *retail level* is plagued with a number of logistical complexities that are highly likely to undermine the Commission-approved Standard Offer Service (SOS) procurement framework covering retail customers. At a minimum, retail choice in the IOU's service territory would no longer be feasible as retail service providers' ability to attract and maintain market share would be seriously impaired. Following a Commission decision to return to rate base regulation, we would expect existing SOS contracts to wind down during a two- to three-year transition period. The IOU or the Authority would assume the traditional load-serving obligation, including resource, portfolio, and risk management responsibilities. Whether or not large industrial customers would retain the freedom to shop when competitive prices warrant is a complex subject outside the scope of this inquiry. However, if such freedom were preserved the consequent economic burden on ratepayers still reliant on the IOU would surely be compounded.

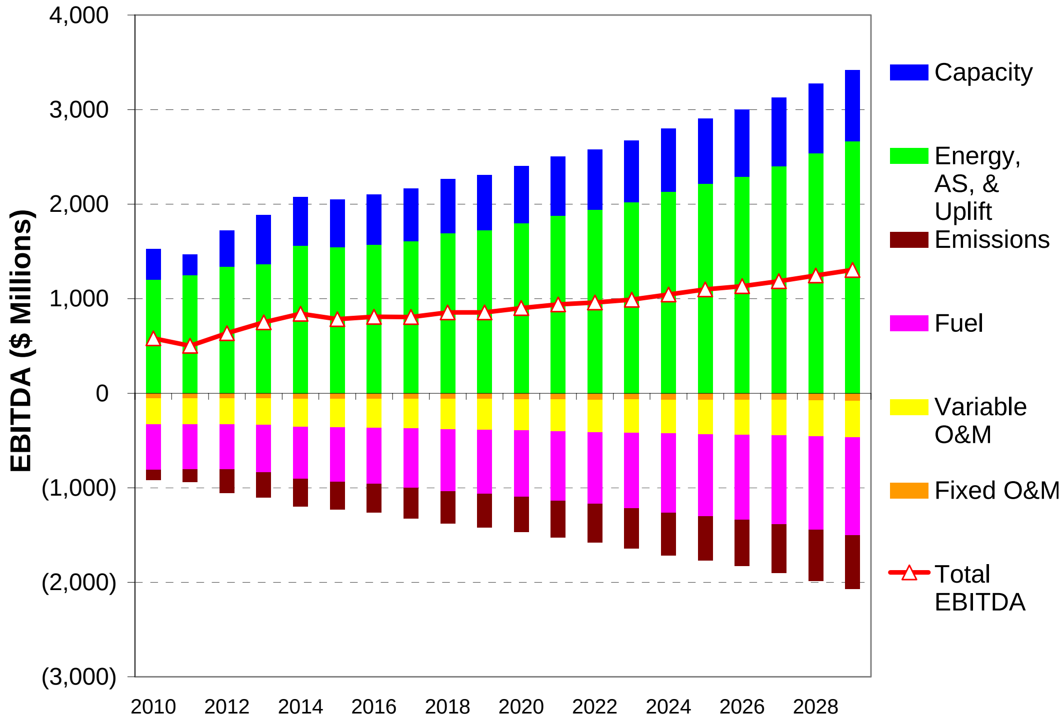
- In performing this analysis LAI has made assumptions about the cost of capital that reflect a return to normalcy in the capital markets, *i.e.*, an IOU allowed equity return of 10% and Authority revenue bonds at 5.6%. If, for whatever reason, the Commission were to later regret the decision to re-regulate the Mirant fleet, investors would nevertheless be entitled to a reasonable return on investment as well as orderly debt retirement in accord with the financial covenants set forth in private placements or revenue bonds. Under IOU ownership, prospective unwinding of a transaction of this financial magnitude should be deemed infeasible.

Fair Market Value of Mirant Generation Fleet

Under prevailing market conditions, the enterprise value of the Mirant fleet is estimated to be $5.1 billion, a reduction of $1.2 billion from the value presented in the Task 3 Report. Using an earnings before interest, taxes, depreciation, and amortization (EBITDA) multiple ranging from 7x to 9x – a conventional range under normal capital market conditions – the range in enterprise value is $4.6 billion to $6.0 billion. The primary reason for the large decline in enterprise value is the unprecedented contraction in global oil prices – a drop of nearly $100 per barrel since July 2008 – and natural gas prices that often set energy prices in PJM. The resultant profitability of Mirant's coal plants is significantly eroded due to lower projected net energy margins over the 20-year valuation period. Countering in part the depressant effect of lower commodity prices on the value of the Mirant fleet are higher estimated capacity prices relative to those used in the Task 3 Report. The change in our forecast of capacity revenues is based on revisions to PJM's planning parameters (*e.g.*, the cost of new entry "CONE", expected peak loads, *etc*.) as well as our acceleration of TrAIL's commercialization from 2014 to 2011, including necessary high-voltage downstream transmission improvements in the District of Columbia and around Baltimore. While the net profits from energy sales are materially reduced under the long-term fuel price forecast incorporated in this study, the capacity price forecast is significantly higher, reflecting capacity prices under "equilibrium" conditions in PJM over the majority of the valuation period.

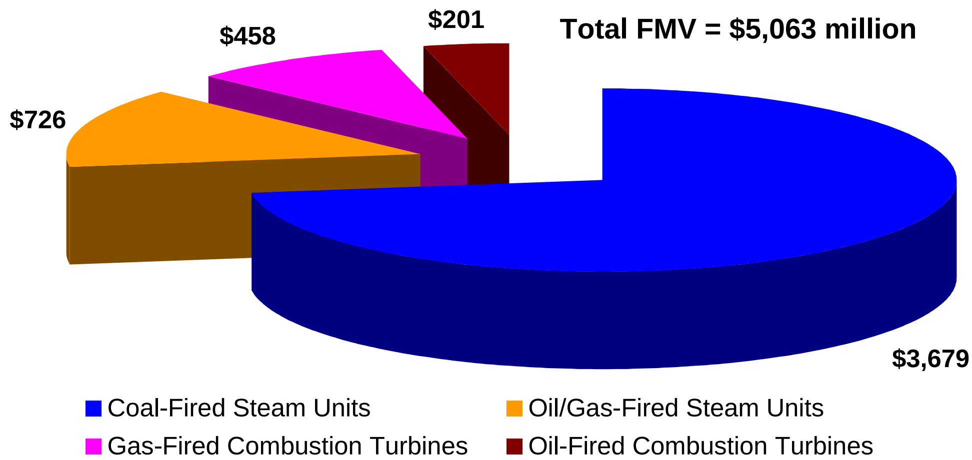
Annual cash flows used to derive FMV are summarized in Figure ES1. Annual revenues have been differentiated to reflect energy and ancillary sales as well as capacity. Operating expenses have also been differentiated to reflect emissions costs, fuel cost, and both fixed and variable operation and maintenance (O&M) costs. The red-line with triangles above the x-axis represents annual EBITDA.

Figure ES1. Mirant Asset EBITDA by Year



Mirant owns 4,588 MW of generation in Maryland; over one-half is coal-based capacity. The coal units were all constructed between 1959 and 1971, and about 1,880 MW of the coal-fired capacity is at least 40 years old. Other capacity includes oil/gas steam plants and combustion turbine (CT) units. As shown in Figure ES2, while Mirant's coal plants represent about one-half of Mirant's total capacity in Maryland, the coal plants comprise $3.7 billion of the enterprise value, about 75%.

Figure ES2. Breakdown of Mirant Asset FMV



Derivation of FMV includes the capital expenditure (CapEx) necessarily incurred in 2009/10 to achieve compliance with Maryland's Healthy Air Act (HAA). Other CapEx related to more stringent standards pertaining to mercury emissions and once-through cooling water systems have not been included in the derivation of enterprise value, but are considered risk factors affecting the distribution of risk-adjusted EVAs. LAI's long-term capacity price forecast has been derived under equilibrium assumptions; therefore, we have included 100% of the "intrinsic" value of capacity in deriving enterprise value. While this convention places upward pressure on FMV, it has little or no bearing on the EVA results.

Economic Value Added

EVA has been calculated in both deterministic and probabilistic terms under IOU and Authority ownership structures. LAI has captured the uncertainty variables in a scenario-based, probabilistic analysis over a 20-year study period, producing a risk-adjusted EVA and the dispersion of EVA outcomes around the expected value. The primary drivers of EVA are oil and natural gas prices, prospective U.S. policy on GHG controls, and the magnitude and duration of the recession. Because the gross domestic product (GDP) growth rate is correlated with global oil prices, we consider these two variables together, *i.e.*, low economic growth rate corresponds to low oil prices, and *vice versa*. Seven scenarios, "S1" through "S7," have been formulated based upon four different global oil price forecasts and two postulated GHG policies, as shown in Table ES1. Each scenario represents an internally consistent set of input variables to the production simulation modeling framework used in both the Task 3 Report and again in this study.

Table ES1. Scenario Definition

		Low GDP	Base GDP	High GDP	High GDP
		Low Oil	**Base Oil**	**High Oil**	**Peak Oil**
GHG Policy	**Moderate Cap**	S3	S1	S2	S7
	Strict Cap	S6	S4	S5	

The Moderate Cap GHG policy outlook assumes that a federal cap-and-trade program for CO_2 allowances will be implemented by 2014. Prices of CO_2 allowances over the forecast period are assumed to be mitigated by a less stringent cap and "safety valve" features such as the use of offsets. Under the Moderate Cap outlook, the price of CO_2 allowances reaches about $31/ton by 2029. The Strict Cap GHG policy outlook assumes that 2012 is the first compliance year under federal GHG legislation. The Strict Cap CO_2 allowance price forecast reaches about $90/ton by 2029. Although the budget proposed by President Obama assumes that GHG auction revenues will be collected by the federal government by 2012, we foresee significant obstacles to speedy legislation and implementation of a workable U.S. allowance market. Our assumed distribution of outcomes for the CO_2 price forecast places more weight on the chance of a Moderate Cap outlook and, therefore, less chance on the Strict Cap forecast.

Premium fossil fuel prices have plummeted since LAI completed the forecast of oil and natural gas prices used in the Task 3 Report. We have incorporated the decrease in current prices and the long-term outlook based on the Department of Energy's (DOE's) 2008 International Energy Outlook (IEO) projections of world oil prices. The intermediate-term price has been reduced based on New York Mercantile Exchange (NYMEX) futures prices. S1 corresponds to the IEO Reference Case and is generally consistent with the *Federal Outlook Scenario* in the Task 3 Report. S2 and S3 correspond to the IEO High and Low forecasts, respectively. S4, S5, and S6 have somewhat lower natural gas and oil prices, reflecting the reduced demand for fossil fuels corresponding to a stricter GHG policy. S7 is based generally on the *Peak Oil Scenario* forecast used in the Task 3 Report. To support probabilistic treatment of fuel prices, we have performed econometric analysis of historic natural gas prices and volatility, including the tendency of oil and natural gas prices to revert to the average after brief intervals when prices collapse or skyrocket. Because fuel prices are a wildcard, the statistical distribution of outcomes for the fuel price forecast is centered on the Base view, but also places substantial weights on Low and High cases.

In addition to federal legislation affecting the regulation of GHG emissions and fuel prices, other independent variables exert influence on the dispersion of EVAs. Six additional "second-tier" variables have been treated in a probabilistic manner, as follows.

- First, we have examined the prospect of much lower or higher capacity prices relative to our base forecast under PJM's RPM to account for changes in Net CONE and other factors over the forecast period.

- Second, we have incorporated a significant allowance for transaction costs covering the due diligence process, legal fees, and closing costs. We have differentiated these costs by ownership structure.

- Third, we have incorporated transition costs associated with the creation of an organizational structure to continue to operate the Mirant generation plants, including headquarters expense and credit revolvers, among other things. These are also differentiated by ownership structure.

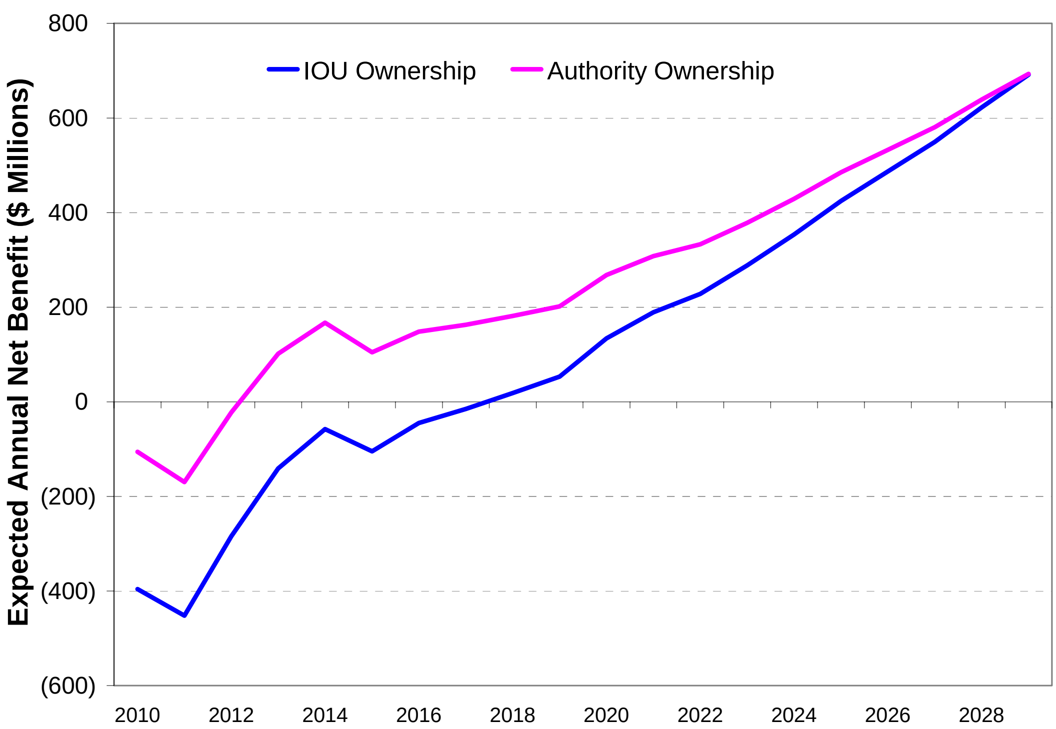
- Fourth, we have tested the effect of a higher cost of equity for IOU ownership assuming the same 50/50 debt/equity capital structure, as well as a significant basis point premium on the cost of taxable revenue bond debt applicable to Authority ownership. The potentially higher cost of general obligation (GO) bonds for other State of Maryland infrastructure projects has <u>not</u> been incorporated in the probabilistic analysis.

- Fifth, we have contemplated stricter environmental regulations that may require additional CapEx for the coal plants to meet a higher performance standard with respect to control of mercury emissions and environmental impacts associated with once-through cooling water systems. At the low end, we consider expenditures for activated carbon injection (ACI) to capture mercury emissions plus retrofit of the cooling water intake structures with fine-mesh screens. At the high end, we postulate a low probability case involving ACI plus replacement of once-through cooling with closed-loop cooling towers.
- Sixth, we have tested the impact of an extended unplanned coal unit outage associated with the aging pulverized coal plants that may be subject to explosions, equipment failures, or other major contingencies. While the impact associated with a major forced outage is potentially large, we have assumed that the likelihood of occurrence is low.

Results

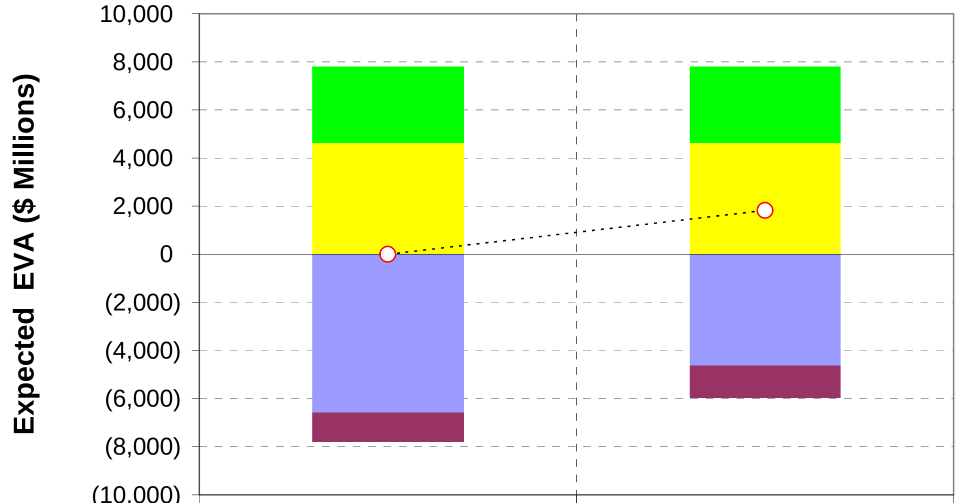
Under both IOU and Authority ownership, the expected benefits, expressed on a risk-adjusted basis, are shown for each year in Figure ES3. Under IOU ownership, the net benefits are deep-in-the-red, or negative, for the first eight years. For Authority ownership, net benefits are negative for the first three years, but the magnitude of the losses is small in relation to the comparable losses under IOU ownership. At the 7.5% discount rate used to value societal benefits and costs, the present value of the risk-adjusted net benefits ranges from *negative* $0.003 billion to $1.82 billion under IOU and Authority ownership, respectively.

Figure ES3. Expected Value of Net Annual Benefits by Ownership



The components of the EVAs under the two ownership structures are shown in Figure ES4. The difference in expected EVA is $1.83 billion, almost all of which is explained by the much higher cost of capital associated with IOU ownership.

Figure ES4. Expected EVA by Component and Ownership



	IOU Ownership	Authority Ownership
Net Energy Revenue	3,178	3,178
Capacity Revenue	4,618	4,618
Fixed Expense	(1,219)	(1,339)
Capital Recovery	(6,580)	(4,632)
EVA	(3)	1,824

The expected net annual benefits lines in Figure ES3 do not reveal the wide uncertainty band for the numerous hard-to-pin-down variables that cloud the outlook under either form of ownership. Figure ES5 and Figure ES6 include confidence level projections at 5%, 50%, and 95% for net annual benefits. The worst 5% of outcomes lie below the 5% confidence level line, and the best 5% of outcomes lie above the 95% confidence level line. Comparing these figures reveals that the 90% confidence uncertainty bands (the range between the 5% and 95% confidence levels) are similar in size for each form of ownership. This is because the key drivers of uncertainty – fuel prices, federal GHG policy, and capacity prices – are *unrelated* to IOU or Authority ownership.

Figure ES5. Annual Net Benefit – IOU Ownership

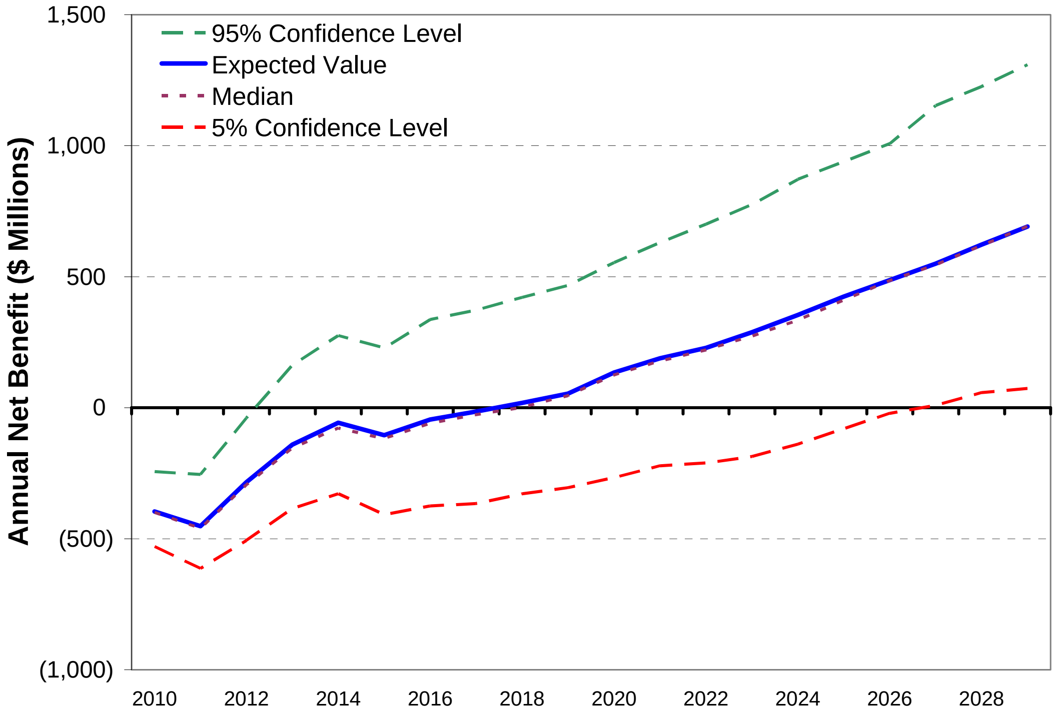
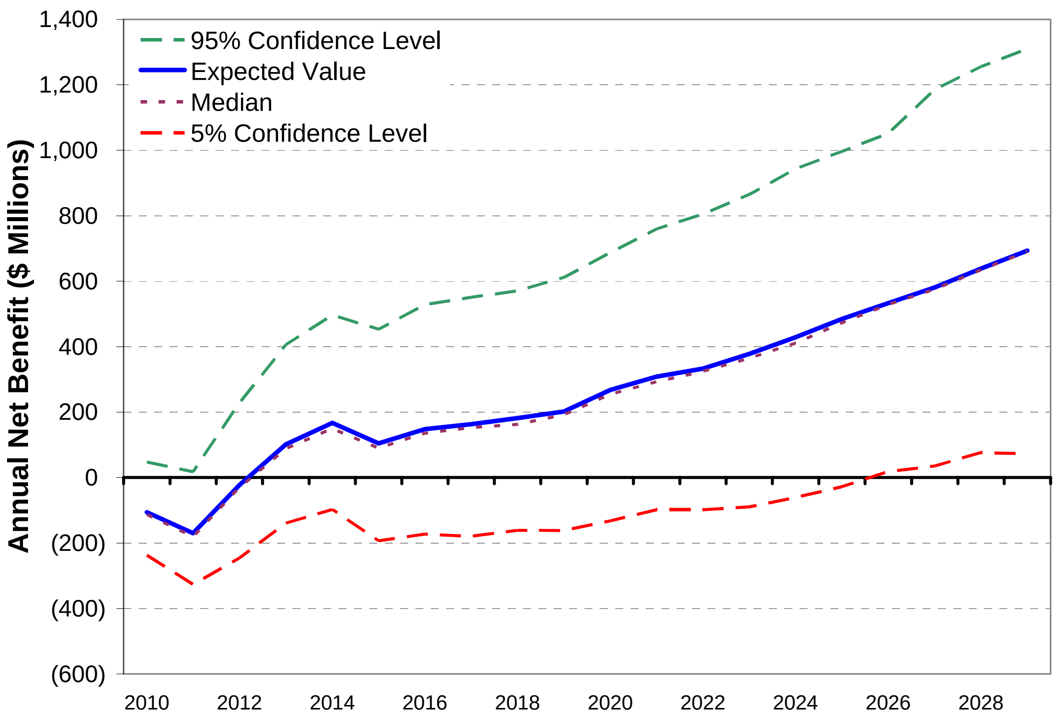
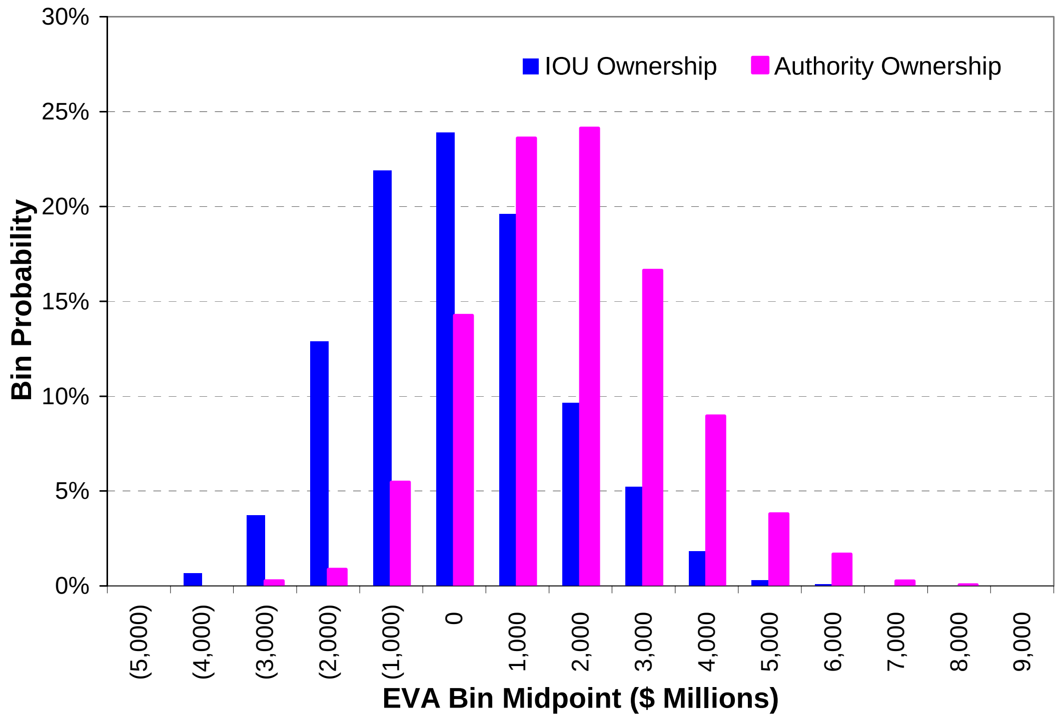


Figure ES6. Annual Net Benefit – Authority Ownership



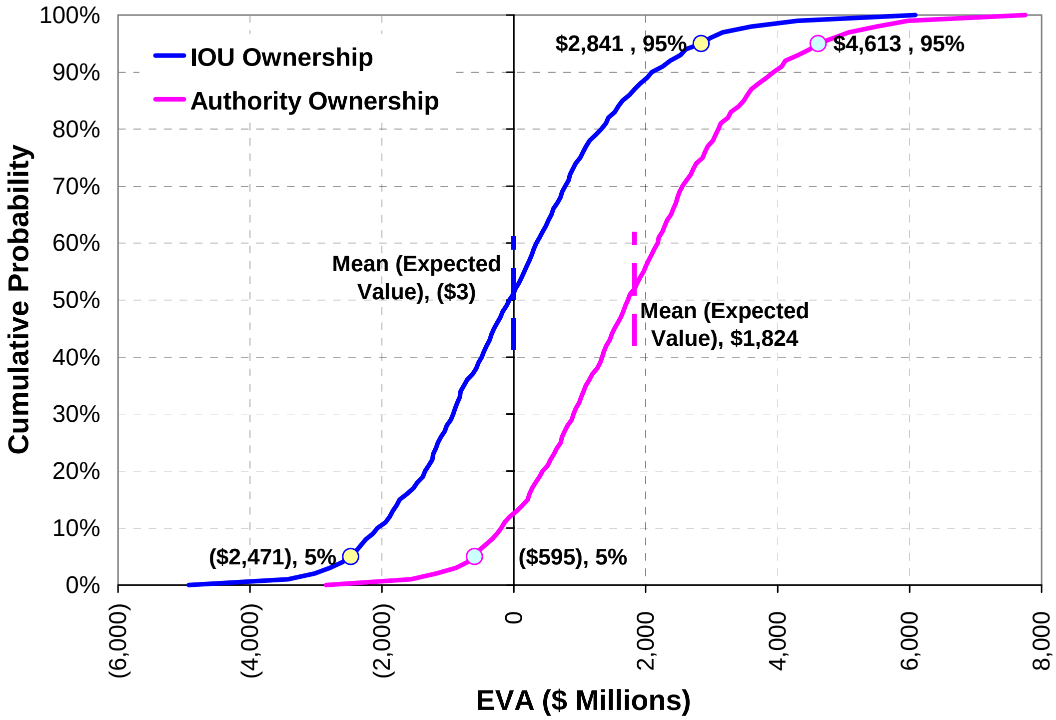
The shape of the uncertainty distribution for the present value of EVA for both IOU and Authority ownership is shown in Figure ES7. The histogram in Figure ES7 is based on “bins” of $1 billion increments on the x-axis, so the results discussed here are the midpoint EVA values of the bins. The IOU ownership distribution has a most likely EVA of zero, with a downside tail extending to negative $4 billion, and an upside tail extending to positive $6 billion. The Authority ownership distribution has a most likely value of $2 billion. Its downside tail extends to negative $3 billion, while its upside tail extends to $8 billion.

Figure ES7. Histogram of EVA Probability Distribution by Ownership



As seen in Figure ES8, the EVA cumulative probability distribution curves for the two forms of ownership have similar shapes. Most important, the EVA cumulative probability distribution curve under Authority ownership is distributed decidedly to the right of the IOU ownership distribution by about $1.8 billion across the entire probability range. While IOU ownership has about a 50% chance of negative EVA, the exposure to losses under Authority ownership is far less, about 13%.

Figure ES8. EVA Cumulative Probability Distributions



To understand the risks of unfavorable outcomes in the two distributions, it is helpful to focus on the lower left side of Figure ES8. In Figure ES9 and Figure ES10 we zoom in on the lower portion of the IOU and Authority ownership distributions, respectively, and show three key risk metrics – Probability of Loss, Expected Loss, and 95% confidence tail value-at-risk (TVaR95), all measured from the zero EVA risk threshold. Simply put, TVaR95 represents the weighted average loss of the *worst* economic outcomes. These key risk metrics have been formulated in the present context in order to address in a consistent and rigorous form either the IOU's or the Authority's downside risk exposure under rate base regulation.

The downside risk measures begin at the threshold of zero loss. From that point, Expected Loss is the mean (average) loss for all outcomes that result in a negative EVA. IOU ownership has an Expected Loss of about $1.28 billion associated with its 51% probability of loss (Figure ES9), compared to an Expected Loss of $0.66 billion associated with a 13% probability of loss for Authority ownership (Figure ES10). In other words, IOU ownership is expected to have a four-fold greater probability of loss, and if a loss occurs, its expected value would be nearly twice as large. The TVaR95 is the expected loss conditional on the outcome being worse than the 5% probability level. For IOU ownership, TVaR95 is $3.1 billion, compared to $1.2 billion for Authority ownership, a difference of $1.9 billion.

Figure ES9. EVA Downside Risk Measures – IOU Ownership

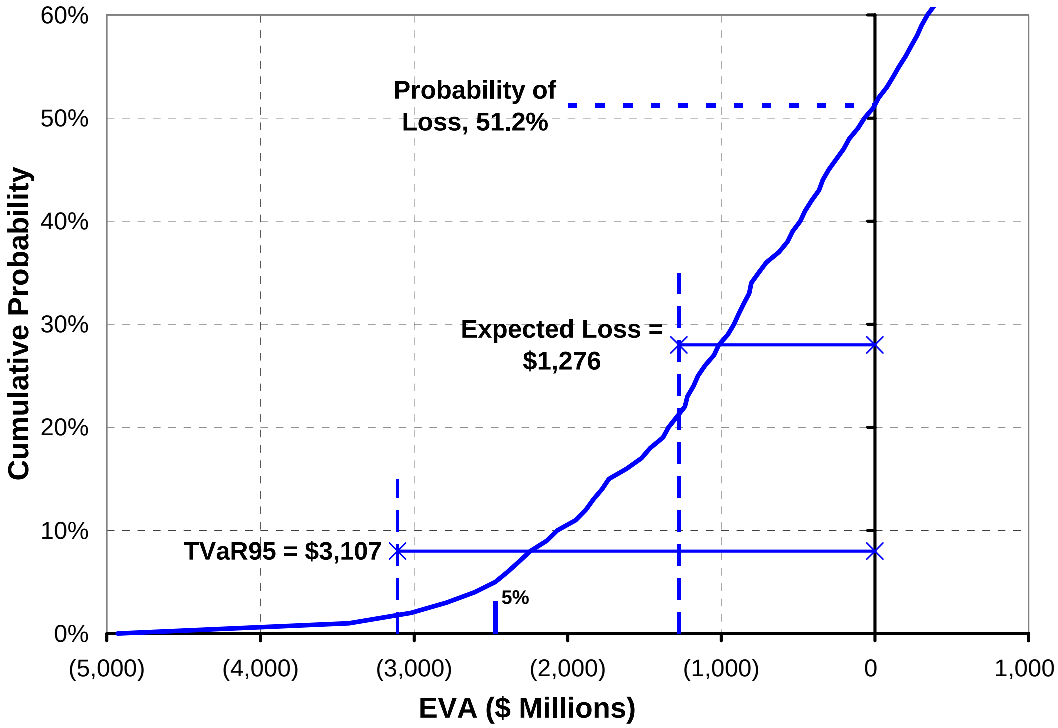
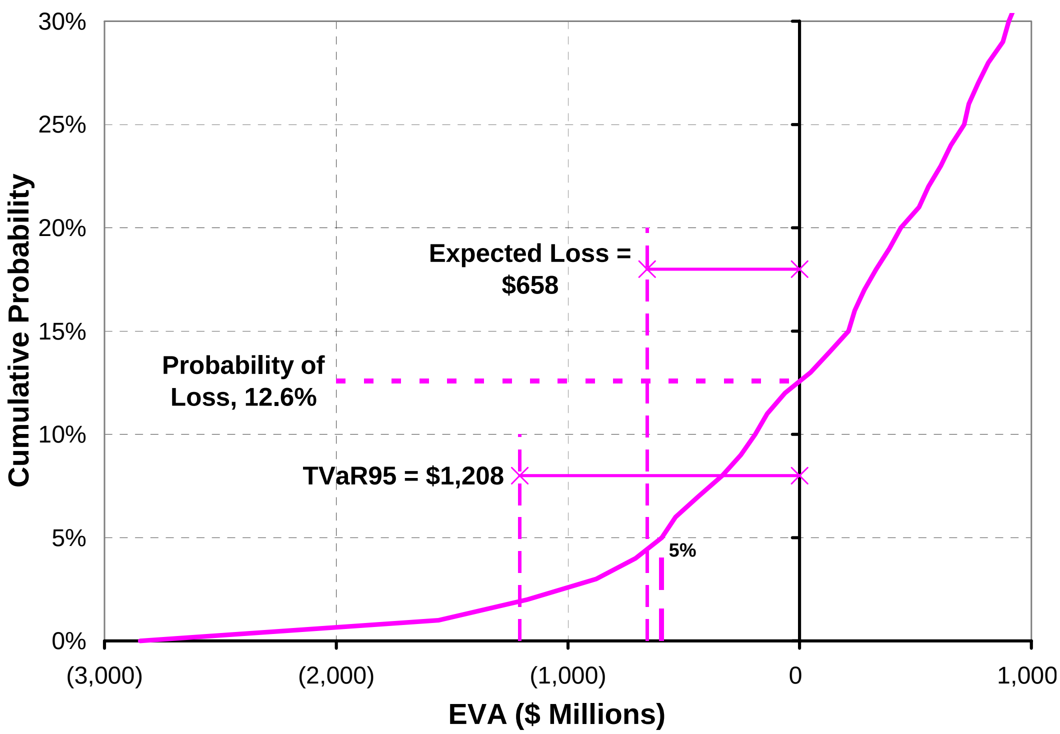


Figure ES10. EVA Downside Risk Measures – Authority Ownership



Across the board, these risk metrics demonstrate the much greater likelihood of negative outcomes under IOU ownership, including larger expected loss, and larger extreme loss relative to the Authority transaction structure. The much more favorable dispersion of economic outcomes under Authority ownership is explained wholly by the substantially lower cost of capital we have assumed would be available to support the formation of an Authority.

1 ECONOMIC, MARKET AND REGULATORY DEVELOPMENTS

Since issuance of the Task 3 Report on December 1, 2008, there have been significant shifts in economic conditions, wholesale power market dynamics, and regulatory developments. The underlying forecast assumptions and factor inputs were based, however, on a perspective of U.S. economic conditions and global oil prices that prevailed in the summer of 2008, more than two months before the global credit crisis. The economic downturn, emerging legislative and executive initiatives under the Obama Administration, recent filings and information from PJM, and the continued slide in commodity prices necessitate a comprehensive update of key factor inputs used in the Task 3 Report.

In this section, we provide the basis for updating the forecasts and assumptions used in this study.

1.1 Economic Conditions

1.1.1 Recession

In formulating our economic and financial assumptions in the Task 3 Report, we noted the unprecedented deterioration in credit fundamentals and liquidity. In Section 2.5.2 of the Task 3 Report, we concluded that "Given the 30-year study horizon in this report, we have made the simplifying assumption that the capital markets will trend towards normalcy in the next two years, reflecting a more typical and stable long-term financial environment…"

Since then, economic conditions have materially worsened. In December, the National Bureau of Economic Research (NBER) declared that the U.S. has been in a recession since December 2007.[1] There is typically a lag between the start of a recession and a formal declaration, allowing for time to finalize and evaluate various economic measures. Those measures include labor and unemployment, as well as real personal income, industrial production, wholesale and retail sales, and GDP. The NBER stated that these last three measures reached a peak between November 2007 and June 2008, and have been declining ever since.

According to a December 2009 *Wall Street Journal* economic-forecasting survey, the current recession may turn out to be the longest and most painful downturn since the Great Depression. The 54 economists who participated in the survey, on average, forecasted quarterly contractions in GDP for Q4 2008 and Q1&2 2009. The Commerce Department's preliminary estimate showed a 0.5% decline in quarterly GDP for the third quarter, so that if the economists' predictions bear out, it would mark the first time GDP has contracted in four consecutive quarters during the post-war period. On average, economists expect the downturn to conclude by year-end 2009. The recession and its longer-term impacts affect LAI's assumptions about long-term inflation, the financial markets, the costs of debt and equity, and load growth, as discussed throughout this report.

[1] The NBER is a private group of leading economists charged with dating the start and end of economic downturns.

1.1.2 Inflation

In the Task 3 Report, we assumed a long-term average inflation rate of 2.5% that underlies fuel prices, power plant expenses, and other costs. In this analysis, we use a lower inflation value of 2.0% that reflects the long-term impacts of the current recession and our outlook that this downturn will be protracted and a rebound will occur slowly. A 2.0% inflation rate is consistent with the Energy Information Administration's (EIA's) most recent IEO, the source of the crude oil forecast that is a key driver in our fuel price, and hence our energy price, forecasts. A 2.0% rate is also the Federal Reserve's target inflation rate.

1.1.3 GDP Outlook

While the current state of the financial markets raises serious concerns about the ability to fund the acquisition of a power plant portfolio on the scale of the Mirant assets in Maryland, we expect that bank and capital market funds will become more liquid as the economy bottoms out and begins to recover later this year. Our view on timing is supported, in part, by the most recent (February 13, 2009) Survey of Professional Forecasters reported by the Federal Bank of Philadelphia. GDP growth in the Survey is expected to be negative in Q1 and Q2 2009 (-5.2% and -1.8%, respectively), low in Q3 (1.0%), and recovering in Q4 2009 and Q1 2010 (1.8% and 2.4%) respectively, indicating that the overall economy may return to a more normal footing by year-end. Over the long term, the most recent economic projection by the Congressional Budget Office, issued on January 7, 2009, projects that real GDP will fall 2.2% in 2009, rise 1.5% in 2010, rebound to 4.0% annually over 2011 to 2014, and then decline to a 2.4% annual rate from 2015 to 2019.[2] GDP forecast assumptions used in our current load forecasts are described in Section 1.1.3.

We recognize considerable uncertainty regarding the near-term state of the domestic economy in spite of the Troubled Assets Relief Program (TARP) and the American Recovery and Reinvestment Act of 2009 (Stimulus Plan) recently signed into law. While the Stimulus Plan provides over $34 billion in funding for improving national energy production, distribution, and transmission systems, half of which will be investments in electric transmission infrastructure, it is not possible to predict with any confidence which projects or investments will be affected or when that effect might be felt. For that reason, we have not explicitly included any modifications that directly reflect TARP or Stimulus Plan funding.

1.1.4 Financial Markets / Cost of Capital Outlook

At this point there is considerable uncertainty about how exactly the TARP monies will be spent and, more importantly, how effective that spending will be. LAI believes it is reasonable to anticipate that equity and debt markets will be functioning more or less normally by year-end

[2] Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2009 to 2019*, January 2009.

2009, the point in time that we have assumed for purposes of this study when either Pepco / Pepco Holdings, Inc. (PHI) or an Authority would acquire the generation assets.[3]

In deriving FMV and EVA we estimate that the *nominal* capital costs for willing merchant buyer, IOU and Authority ownership will be lower due to our assumption of a lower long-term inflation rate. Based on our outlook that capital markets will return to some sense of normalcy, we see no fundamental reason to alter the real cost of capital. Hence, the costs of equity and debt capital will be 0.5% lower for each ownership structure, consistent with the lower long-term inflation rate. In addition, we note that the equity rate assumption for merchant financing used in the Task 3 Report for calculating FMV was based on a consistent PJM, New York Independent System Operator (NYISO), and ISO New England (ISO-NE) assumption, namely, that "…market capacity mechanisms would be stable because capacity additions would be 'rational' in quantity, type, and timing."[4] Since the comparatively recent inception of capacity markets, none of the three capacity markets has sustained rational behavior – all three market areas have an oversupply of capacity that we expect will persist for many years in spite of unforced capacity (UCAP) prices below net CONE. Thus we believe that a willing buyer of the Mirant fleet would include an equity risk premium to account for the uncertain and unstable operating revenues derived under the existing PJM market design. This premium has been conservatively estimated to equal 150 basis points (bp) – it could be higher, but, in LAI's opinion, probably not much lower.

Table 1 compares the current cost of capital assumptions to the assumptions in the Task 3 Report.

Table 1. Acquisition Cost of Capital Assumptions

	Merchant Buyer		**IOU**		**Power Authority**	
	Task 3 Report	Current Study	Task 3 Report	Current Study	Task 3 Report	Current Study
Debt/Equity	50/50	50/50	50/50	50/50	100/0	100/0
Debt Term	20	20	20	20	20	20
Debt Rate	7.5%	7.0%	7.0%	6.5%	6.1%	5.6%
Equity Rate	12.5%	13.5%	10.5%	10.0%	n/a	n/a

[3] Our working assumption of a year-end 2009 financing to support a January 1, 2010, transaction date is merely a simplifying study convention. Given the significant corporate, legislative, and/or regulatory hurdles that must be overcome, it will take much more time to complete the transaction. To the extent that any acquisition financing were to occur in 2010 or 2011 the odds improve that the financial market will have returned to normalcy.

[4] In LAI's *ICAP Demand Curve Study* for NYISO in which we developed cost of capital assumptions, we made similar assumptions that "[c]apacity, energy, and ancillary services from postulated gas turbine peakers can be 'merchandized' at compensatory prices, *i.e.*, sold at market-based prices that provide equity investors with a reasonable return on investment."

1.2 GHG Controls

Since January 1, 2009, CO_2 emissions from fossil fuel-fired power plants 25 MW and larger in the ten Regional Greenhouse Gas Initiative (RGGI) states, including Maryland, have been subject to a cap-and-trade system for controlling GHG emissions. In the Task 3 Report, the cost of CO_2 emission allowances was incorporated as a variable operating cost, initially for all fossil fuel-fired units in the RGGI states, and subsequently expanded as a federal program in 2014 over the entire study area. We considered 2014 to be the earliest date that a CO_2 cap-and-trade program could be implemented on a national scale. Recognizing considerable uncertainty in the CO_2 market, we assumed that the starting price would be in the neighborhood of the RGGI Stage 1 trigger price of $7/ton (2005$) through 2013. Thereafter, we anticipated real increases in the allowance prices, reflecting the onset of a federal program and a ratcheting down of the GHG cap.

The first auction for 2009-vintage RGGI allowances was conducted on September 25, 2008, and produced a clearing price of $3.07/ton. Only six states participated in this auction and the number of allowances offered was only a small percentage of the total allocation for all RGGI states. The second auction, with all RGGI states participating, was held on December 17, 2008, with a clearing price of $3.38/ton. As of February 23, 2009, the NYMEX Green Exchange reports RGGI monthly futures through December 2011 at $3.60/ton, although trading volumes appear to be very thin. These initial RGGI allowance prices appear to reflect the fact that the market is still nascent and that the anticipated generation in 2009 is lower than forecasted at the time that the RGGI reduction targets and cap were established.

The Obama Administration and the new Congress appear to desire quick action on national GHG legislation. A number of bills have been introduced in both houses of Congress over the last few years, which consider a range of mechanisms for achieving targeted GHG reductions. We continue to assume that future federal GHG legislation will be in the form of a cap-and-trade system rather than a carbon tax. One model proposal may be S. 3036, the Boxer-Lieberman-Warner *Climate Security Act of 2008*. Senator Boxer, Chair of the Senate Committee on Environment and Public Works, and Senator Bingaman are reportedly collaborating on a new bill based on a cap-and-trade system, to be introduced in Congress prior to the United Nations Climate Change Council on December 7, 2009. Representative Waxman, Chairman of the Committee of Oversight and Reform, has also announced he is working on a new cap-and-trade bill.[5]

Despite the current focus on economic recovery and banking reform measures, it is nevertheless likely that Congress will consider GHG legislation by the end of 2009. The budget that President Obama submitted to Congress assumes that the federal government will begin collecting revenue from the sale of allowances by 2012. Considering that the first auction was not conducted until three years after the RGGI states signed the Memorandum of Understanding

[5] Other current legislation considered in the 111th Congress includes Bill H.R. 232, Baldwin's Greenhouse Gas Registry Act, which proposes a national Greenhouse Gas Registry, and Bill H.R. 594 Stark's Save our Climate Act of 2009, which proposes a national carbon tax, increasing at a rate of $10/year until an 80% reduction of GHG below 1990 levels are observed.

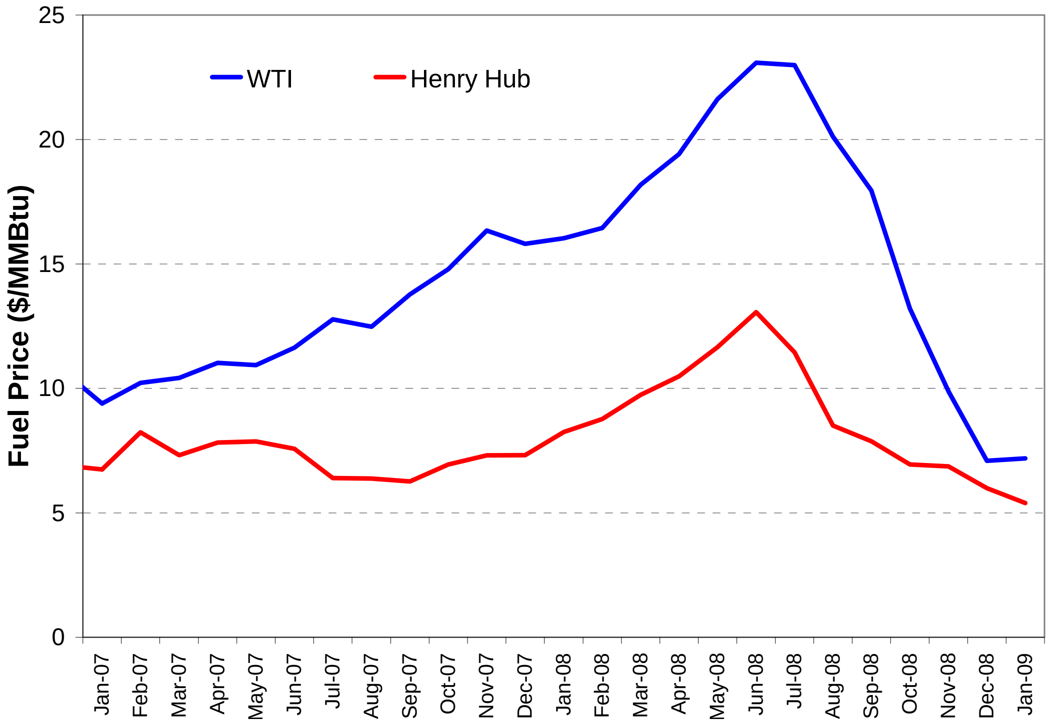
that had already established each state's CO_2 budget, we believe that three years to roll out a national trading system encompassing a broader economic sector is aggressive. Regional differences between states that rely more heavily on coal versus states that rely more heavily on natural gas versus states with large wind resource potential will surely lead to protracted debate in both the Senate and the House. We continue to believe that a CO_2 allowance market will be implemented on an expedited basis, although exactly how and when a workable, national cap-and-trade market will be in place is uncertain.

1.3 Fuel Price Outlook

The *Base Scenario* in the Task 3 Report was oriented around the fuel price forecasts comprising the *Conventional Wisdom Scenario*, which reflected supply and demand trends typical of the prior ten years, in particular, tight energy supplies and continued robust demand in India and China. In the *Conventional Wisdom Scenario*, crude oil prices were projected to decline for a few years, from an annual average price in 2008 of $118/Bbl to $100/Bbl by 2014. Slowing production and diminishing global reserves growth subsequently were expected to result in increasing prices, reaching $144/Bbl in 2029. The *Conventional Wisdom Scenario* also projected that natural gas prices at the Henry Hub will decrease from an annual average of about $9.88/MMBtu in 2009 to an average of $8.41/MMBtu in 2014 and then increase to around $13.50/MMBtu by 2029.

The bubble in premium fossil fuel prices burst in the fall of 2008. A combination of market and financial developments events has resulted in a dramatic decline in commodity prices since last August. The decline reflects demand and supply responses to high prices along with the rapidly developing global economic recession. High prices leading up to the summer price spikes ultimately reduced energy commodity demand while at the same time contributing to increasing supplies. The recession is putting major downward pressure on prices as well. Figure 1 shows the paths of spot West Texas Intermediate (WTI) crude oil and Henry Hub natural gas prices from January 2007 through January 2009. In 2008, according to the International Energy Agency, global oil demand contracted for the first time in 25 years, while in another development that tended to depress energy commodity prices, EIA reported that U.S. natural gas production increased by 8% for the first 11 months of 2008 compared to the first 11 months of 2007.

Figure 1. Historical Spot Crude Oil and Natural Gas Prices



Since peaking in the summer of 2008, commodity fuel prices have continued to decline. While the decline has been steepest in the "front month" NYMEX futures, longer-dated futures prices have likewise declined materially relative to the futures prices that prevailed last summer. Crude oil prices dropped 69% since July and natural gas prices have dropped 59% since June. Spot coal prices (Central Appalachian) have dropped 51% since August. Relative to the forecast values defined last summer and used to derive the FMV of the Mirant fleet, fuel prices have declined over 60%. The low fuel price scenario in the Task 3 Report, the *Federal Outlook Scenario*, now appears to better match the recent market movements and the expected long-term value trend.

While NYMEX futures contracts are showing increasing prices over the next few years, the futures markets do not anticipate a return to last summer's price levels anytime soon. As of settlement in late February, the average annual futures strips for crude oil increase from $54.60/Bbl for 2010 to $69.25/Bbl for 2014. Natural gas futures strips increase from $5.90/MMBtu for 2010 to $7.13/MMBtu for 2014. Coal futures have a shorter forward period, but nonetheless show average annual prices increasing from $59.42/ton in 2010 to $63.97/ton in 2012.

1.4 PJM and Maryland Load Growth

In the Task 3 Report, the load forecast for our chronological simulation model was derived from the most current PJM and other ISO load forecasts available. The principal load forecast data source was PJM's *2008 Load Forecast Report* (*2008 Report*), issued in May 2008. The PJM Regional Transmission Organization (RTO) coincident peak demand was forecast to be 140,407

MW in 2009. Non-coincident peak demand was forecast to be 27,675 MW in 2009 for the four load zones covering Maryland:

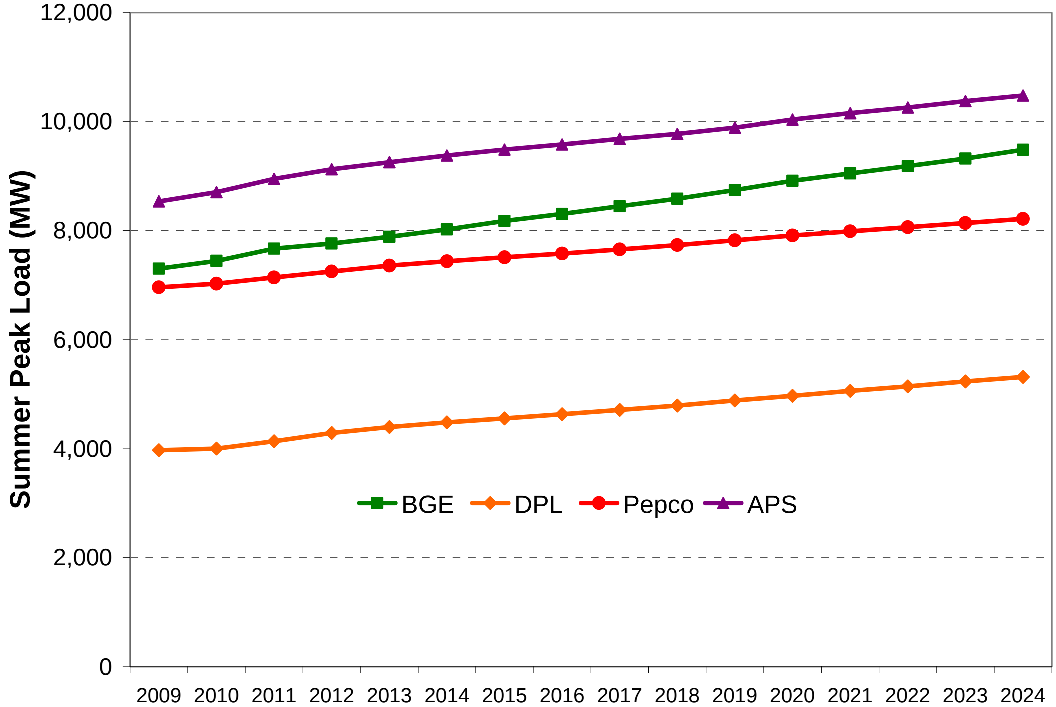
- Baltimore Gas & Electric (BGE),
- Delmarva Power & Light (DPL),
- Pepco, and
- Allegheny Power System (APS).

In the updated *2009 Load Forecast Report* (*2009 Report*) issued in January 2009, PJM projects that the economic recession, as forecasted by Moody's Economy.com, will cause peak demands in most PJM zones to be lower in 2009 than in 2008. According to the *2009 Report*, the PJM RTO coincident peak demand is forecast to be 134,428 MW in 2009, a reduction of 5,979 MW from the forecast presented in the *2008 Report*. The forecast RTO peak for 2009 is also expected to be less than the weather-normalized actual 2008 summer peak of 136,315 MW. The non-coincident peak demand for the Maryland zones is forecast to be 26,773 MW in 2009, a reduction of 902 MW from the previous forecast.

According to the *2009 Report*, an economic rebound forecasted in 2010 is expected to cause load growth to resume, although summer RTO peak load will not exceed the 2008 level until 2011. Summer peak load growth for the PJM RTO is projected to average 2.1% over the first five years (2009-2014), 1.2% for the second five year period (2014-2019), and 1.0% over the last five year period (2019-2024). PJM's forecast is based, in part, on forecast RTO gross metropolitan product (GMP) growth averaging 2.9% over the first five years, 1.7% for the second five years and 1.1% over the last five years

PJM's *2009 Report* forecasts that several zones will have notably different load growth patterns compared to the *2008 Report*. The BGE zone is one of two that has a notably different economic outlook. The BGE zone is expected to have accelerated load growth as a result of the U.S. military's Base Realignment and Closure (BRAC) Program. PJM also reports that the outlook for the APS zone has been impacted by an enhancement to PJM's forecast model to account for large historical load shifts. Over the next 15 years, annual summer peak load growth for the BGE zone is projected to average 1.8%. Over the same period the projected growth rates for the other Maryland Zones will be 2.0% for DPL, 1.1% for Pepco and 1.4% for APS. Figure 2 shows the summer peak loads for the Maryland Zones based on Table B-1 in the *2009 Report*.

Figure 2. Summer Peak Load Growth Forecast for the Maryland Zones



LAI contacted representatives of BGE and APS for further insight regarding the *2009 Report*. BGE reported to us that they were comfortable with the *2009 Report* as it currently stands. BGE agrees with PJM that the BRAC Program is the primary driver of accelerated load growth for the BGE zone due to the expected addition of higher paying jobs in the area and the resultant construction and/or office development. APS reported to us that they believe the differences in the *2008 Report* and *2009 Report* for APS are primarily due to incorporating the revised economic measures from the Moody's outlook. APS also reported that between 2005 and 2006, two significant load changes occurred in the APS zone. First, the Ohio load that was served by APS was transferred to American Electric Power (AEP) at the end of 2005. Second, the largest industrial customer in APS's zone (>300 MW) significantly reduced its load near the end of 2005. APS explained that PJM enhanced its forecasting model to better account for historic load shifts in its most recent forecast.

One important consequence of PJM's lower peak demand forecast is the potential disappearance of a capacity "gap" in SWMAAC or in Maryland. According to a February 25, 2009, presentation by PJM to the Commission, there may not be a gap in 2011/12 under base case scenario assumptions of lower loads and more demand response (DR), even without TrAIL, although under those circumstances, the transmission system will be at or near its capacity. With TrAIL (as discussed in the next section), PJM expects there would be a sufficient capacity margin to assure reliability.

1.5 Transmission Infrastructure

1.5.1 TrAIL's In-Service Date

The *Base Scenario* in the Task 3 Report assumed that the TrAIL transmission project would be in-service in 2014, about three years after TrAIL's developers and PJM had indicated planned commercial operation. This was intended to be a conservative assumption based on the uncertainties surrounding the ability of the project to get all regulatory approvals in time for construction.

TrAIL has now received all of the state public utility commission approvals for construction from Pennsylvania, West Virginia, and Virginia. On February 13, 2009, the WV Commission also denied the Petitions for Reconsideration of its Final Order filed by several parties.[6] Responding to a petition by the TrAIL Company (TrAILCo), the WV Commission reconsidered two critical aspects of the Final Order:

- The WV Commission will now allow TrAILCo to begin construction in segments upon filing verifications that all permits and approvals have been obtained for that specific segment. The WV Commission's Initial Order would have prevented TrAILCo from beginning construction on any WV segment until a hearing was held and a determination made as to whether all pre-construction permits and approvals had been obtained and all pre-construction conditions had been met for the entire line in the state.
- The WV Commission will not require TrAILCo to install a $50 million Static VAR Compensator at the Meadow Brook Substation in Virginia because it would no longer be necessary to provide voltage benefits once the line is in-service.

Having received all of the necessary state commission approvals for construction, we believe the project is now on track for a 2011 in-service date.[7] All LAI scenarios therefore reflect a TrAIL in-service date in 2011. We do not consider either a delay or conceivable cancellation of TrAIL. The TrAIL+PATH alternative scenario included in the Task 3 Report has not been reformulated in this study.[8]

1.5.2 SWMAAC and EMAAC Transfer Limits

In the Task 3 Report, LAI did not conduct transmission power flow or security-constrained dispatch modeling of TrAIL to determine the transfer limits of relevance to SWMAAC and Eastern MAAC (EMAAC). For purposes of defining the change in the Capacity Emergency Transfer Limit (CETL) attributable to TrAIL, PJM recommended that the Commission compare the CETL values in the 2010/11 Planning Parameters (pre-TrAIL) to the CETL values for

[6] On August 1, 2008, the WV Commission issued its Final Order granting a certificate of convenience and necessity to TrAIL for the construction and installation of the West Virginia segments of the line.

[7] The commercial operation date for TrAIL is consistent with the February 25, 2009, presentation by Michael Kormos, Executive Vice President of PJM to the Commission.

[8] The Potomac Appalachian Transmission Highline (PATH) is described in Section 3.2.4 of the Task 3 Report.

2011/12 (post-TrAIL). Based on this PJM-recommended methodology, the increase in CETL attributable to TrAIL was at least 230 MW for SWMAAC and at least 290 MW for EMAAC.[9]

During the course of our due diligence in 2008, the Commission sought technical information from PJM for purposes of defining the anticipated change in CETL for the relevant zones in Maryland.[10] We interpreted PJM's response as confirmation that 6,897 MW should be treated as the actual 2011/12 CETL for SWMAAC and 8,514 MW as the actual 2010/11 CETL for EMAAC. In the Task 3 Report we acknowledged that these CETL values may constitute a lower limit, but elected to use them in accordance with our interpretation of what PJM recommended to the Commission.

PJM has recently recalculated the SWMAAC CETL to account for significant transmission improvements in the District of Columbia and around Baltimore. On January 30, 2009, PJM posted the Planning Parameters for the 2012/13 RPM auction. The SWMAAC CETL is now shown as 7,400 MW, 733 MW higher than the 2010/11 pre-TrAIL value of 6,667 MW and 503 MW higher than the 2011/12 post-TrAIL value incorporated in the Task 3 Report.[11] We have incorporated the much higher CETL assumptions based on this current information from PJM. In a meeting among Commission staff, LAI, and senior PJM staff on February 4, 2009, PJM explained that:

- PJM posted a SWMAAC CETL of >6,897 MW for the 2011/12 RPM auction because under the 5% Capacity Emergency Transfer Objective (CETO)/CETL LDA test, PJM was under no obligation to run its load flow models beyond that cut-off limit. However, with the introduction of the proposed 15% CETO/CETL test, PJM now reports the CETL value beyond the 15% cut-off limit. Hence, PJM reports an actual value of 7,400 MW for 2012/13, which is 124% above the SWMAAC CETO. The CETL value reported also reflects the expected retirement of both Benning and Buzzard Point units in 2012.
- The change in CETL does *not* incorporate the start-up of PATH.
- The SWMAAC CETL increase also includes several transmission upgrades in the District and around Baltimore. The biggest contributor to the CETL increase is the Burches Hill transformer.

In this study we therefore use the updated CETL values for SWMAAC, EMAAC (9,079 MW), and MAAC (6,377 MW), consistent with our capacity price forecast. These values are held

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[9] The 2010/11 CETL value for SWMAAC was 6,667 MW and the 2011/12 CETL value was reported as >6,897 MW, a difference of 230 MW. PJM recommended that this difference should be used as an approximate proxy for the CETL change in SWMAAC attributable to TrAIL. The 2010/11 CETL value for EMAAC was >8,514 MW and the 2011/2012 CETL value for EMAAC was 8,804 MW, a difference of 290 MW. LAI noted in the Task 3 Final Report that it was not clear whether the >6,897 and the >8,514 values for SWMAAC and EMAAC are the actual values.

[10] Of particular interest was the actual CETL values for each local deliverability area (LDA) and not the 10% cut-off point which >6,897 MW and >8514 MW appear to represent.

[11] A 7400-MW CETL for SWMAAC is consistent with the February 25, 2009, presentation by PJM to the Commission.

constant over the study period for all scenarios. No sensitivity analysis was performed using the prior CETL assumption.

1.6 PJM Reliability Criterion

Based on PJM's *2007 Reserve Requirement Study*, the Task 3 Report incorporated a 15.5% Installed Reserve Margin (IRM) for the PJM system. The IRM was treated as a constant over the planning horizon. The *2008 PJM Reserve Requirement Study* recommended that PJM's IRM for the 2012/13 Delivery Year be increased to 16.2%.[12] The recommendation has been approved by the PJM Board and is posted on its website. PJM also posted the associated Forecast Pool Requirement[13] of 1.0872 together with the other Planning Period Parameters, which will be used in the 2012/13 Base Residual Auction scheduled for May 2009.

1.7 Capacity Market

1.7.1 RPM Process

In Section 2.2 of the Task 3 Report, LAI described RPM, PJM's market mechanism for establishing locational capacity values. We briefly described the background that led to the establishment of RPM, its basic functions, and results of the five auctions that established UCAP prices for the delivery years 2007/08 through 2011/12. We noted that PJM was in the process of updating the RPM parameters through a stakeholder process and provided then-current proposed Gross CONE values that we used to forecast UCAP prices. We cautioned that "the proposed values have not achieved consensus among market participants – much less been approved by the PJM Board…" and that "the CONE values ultimately agreed upon by PJM stakeholders may vary significantly from these proposals." While the most recently proposed CONE values are not dramatically different from our previous values, there have been other changes that put upward pressure on our forecast of clearing prices.

1.7.2 Update on CONE / Stakeholder Process

There have been a number of capacity market developments since the Task 3 Report, summarized below, that we used to update our forecast of UCAP prices in SWMAAC. The four most important developments are as follows:

- PJM's proposed RPM Amendments to the PJM Tariff filed with the Federal Energy Regulatory Commission (FERC) on December 12, 2008 (Docket No. ER09-412),
- PJM's Planning Parameters for the upcoming 2012/13 RPM auction dated January 30, 2009,
- PJM's and the Load Group's Offer of Settlement filing of February 9, 2009, and

[12] *2008 PJM Reserve Requirement Study – 10-year Planning Horizon: June 1st 2008 – May 31st 2018*, October 8, 2008.
[13] The IRM expressed in UCAP terms.

- Supplier Caucus Comments to the Offer of Settlement filing of February 17, 2009.

PJM market rules require regular reviews of the RPM mechanism and its inputs. Under FERC's September 19, 2008, *Order on Motion for Technical Conference*, PJM was required to address RPM issues and shortcomings. FERC must approve or reject any RPM tariff revisions by March 27, 2009, in order for those revisions to be incorporated in the May 2009 auction for the 2012/13 delivery year.

1.7.2.1 PJM's Proposed RPM Amendments

PJM stakeholders tried to establish RPM input parameters through the PJM Markets and Reliability Committee and the Capacity Markets Evolution Committee, but were unsuccessful. As a result, PJM requested that FERC authorize a settlement process to hammer out compromise parameters under a FERC Administrative Law Judge (ALJ). On December 12, 2008, PJM submitted two filings to FERC. The first filing reported that the stakeholder committees had failed to reach consensus on the most significant RPM issues, and that the stakeholders were continuing to work through a settlement process under the auspices of ALJ Citron. In the second filing, PJM proposed its own compromise tariff revisions based on stakeholder discussions to date, as well as on an independent report prepared by the Brattle Group. The principal revisions filed by PJM are as follows:

- Gross CONE for a gas turbine (GT) peaker will be updated from its current value of \$72/kW-year to \$125-\$135/kW-year, depending upon the PJM area in which it is used.[14]
- PJM proposed to increase the CETL/CETO threshold for which PJM would calculate an LDA's capacity price from 105% to 115%. This may increase the number of LDAs in the future that will have separate capacity clearing prices.
- PJM proposed objective criteria to set "bright lines" that address the uncertain timing of proposed and approved transmission projects. Transmission projects can significantly affect system congestion and hence locational capacity prices given RPM's three-year forward design.
- Interruptible Load Resources will no longer be able to receive capacity revenues without participating in the RPM auctions. Instead, there will be special provisions for these and other short-term resources (such as non-dispatchable energy efficiency resources that reduce peak load) to participate in the RPM auctions and receive capacity resources based on measurement and verification requirements.
- New entrants will be permitted to bid for and receive a capacity price for up to five years rather than just one year (similar to the Forward Capacity Market "FCM" in ISO-NE) provided the plant is located in an LDA that will have a separate capacity clearing price calculated.

[14] In the Task 3 Report LAI expected that CONE values would be increased and therefore assumed Gross CONE of \$131/kW-year.

Net CONE will continue to be calculated by subtracting Energy and Ancillary Services (EAS) revenues (net of fuel and operating expenses) from Gross CONE. EAS revenues will continue to be determined on a rolling 3-year historical basis for a GT peaker proxy.

The manner in which Net CONE for the RTO is established has changed since the Task 3 Report. The forecast contained therein relied on PJM's November 10, 2008, proposal, in which PJM had proposed to set Net CONE for the RTO equal to the lowest *Net* CONE of any region. As a result, Net CONE for the RTO and SWMAAC were identical in that forecast. As shown in the 2012/13 Planning Parameters, Net CONE for the RTO is now calculated as the lowest *Gross* CONE of any of the regions (in this case SWMAAC), minus the EAS offset for the RTO reference unit. Because the offset for the RTO reference unit is lower, Net CONE for the RTO is substantially higher than Net CONE for either MAAC or SWMAAC. The difference is a key driver of the higher capacity clearing prices shown in Section 4.6.

1.7.2.2 PJM's Planning Parameters

The Gross CONE, EAS, and Net CONE values for the regions relevant to this analysis were filed with FERC on December 12, 2008, and posted by PJM in the 2012/13 Planning Parameters on January 30, 2009. These values are provided in Table 2, along with the MAAC / SWMAAC values from PJM's November 10, 2008, proposal that we used in the Task 3 Report.[15]

Table 2. PJM CONE Values for 2012/13

	November 10, 2008 PJM Proposal	**PJM December 12, 2008 Filing / Posted Planning Parameters for 2012/13**		
	MAAC / SWMAAC	RTO	MAAC	SWMAAC
Gross CONE ($/MW-yr)	$131,806	$125,409	$135,600	$125,409
EAS Offset ($/MW-yr)	$50,483	$27,483	$49,524	$52,665
Net CONE ($/MW-day; UCAP)	$238.14	$286.76	$252.06	$213.02

The 2012/13 Planning Parameters include 2,852 MW of load for Duquesne Light Company which had left but decided to return to the PJM market. The 2011/12 RPM auction excluded Duquesne's load but included the associated capacity resources. It is believed that the extra capacity depressed UCAP prices for 2011/12. Returning Duquesne's load to RPM should increase UCAP prices beginning in 2012/13. Separate clearing prices will be calculated by PJM

[15] The Task 3 Report listed an installed capacity value of $222.80/MW-day for Region 2, which is equivalent to the UCAP value of $238.14/MW-day shown here.

for SWMAAC, MAAC, and RTO in the 2012/13 auction. The Mirant assets will receive clearing prices based on the highest of the three LDAs.[16]

1.7.2.3 PJM and Load Group Offer of Settlement

After formal settlement discussions at FERC were terminated pursuant to a January 15 Order, a group of PJM stakeholders representing various load-serving entities and users (PJM Load Group), along with PJM, filed an Offer of Settlement on February 9, 2009. A number of state commissions (including Maryland's) stated that they would not oppose the terms of the Offer of Settlement. The Offer of Settlement included, among other provisions, a proposal to reduce the Gross CONE values by 10%, switch to an "empirical" CONE adjustment process, and extend the new entry Commitment Period to seven years.

1.7.3 Study Assumptions

Given the uncertainty regarding the RPM parameters, it is not possible to predict how the RPM mechanism will be modified for the 2012/13 auction or for subsequent auctions. It is unlikely that FERC will decide which modifications to approve until at least late-March 2009. Nevertheless, it is highly likely that FERC will increase CONE substantially from previous levels, and the current PJM planning parameters based on the December 12, 2008, filing represent a plausible outcome, given the divergent views. Thus, for purposes of this study, we have used the CONE values and other RPM parameters contained in PJM's December 12th filing. While the proposed settlement sponsored by PJM and the Load Group would reduce the CONE value by 10%, that is still well within the ±25% range of UCAP price uncertainty that we have modeled. LAI's capacity price forecast is presented in Section 4.6.

1.8 Mercury Emissions Controls

On May 18, 2005, the U.S. Environmental Protection Agency (EPA) issued the Clean Air Mercury Rule (CAMR) which was designed to reduce mercury emissions from coal-fired power plants. Under CAMR, mercury emissions were to be reduced in two phases. The first phase, beginning in 2010, would have reduced nationwide mercury emissions by about 20%. The second phase, scheduled for 2018, was intended to reduce mercury emissions by 70%. CAMR would have created a national cap-and-trade system for mercury, and also would have removed power plants from the list of sources of hazardous air pollutants under Section 112 of the federal Clean Air Act.

A number of parties, including several of the states that were implementing more stringent mercury emissions regulations, filed a petition for review in the U.S. Court of Appeals for the D.C. Circuit challenging CAMR and the delisting of the coal-fired power plants as sources of hazardous air pollutants with regard to mercury. On February 8, 2008, the D.C. Circuit issued a

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[16] Although SWMAAC has a CETL/CETO ratio great than 115%, PJM has decided to calculate separate clearing prices for any LDA that has exhibited a binding constraint within the last three years. Therefore, separate clearing prices were calculated for MAAC, EMAAC, SWMAAC, Public Service Electric & Gas (PS), PS North, and DPL South as well as the RTO, despite the fact that the CETL/CETO ratio is greater than 115% in each of those regions except PS, PS North, and MAAC.

decision declaring that CAMR was invalid and thus vacated. As a consequence of this decision, the EPA is required to develop mercury emissions standards for coal-fired power plants that reflect emissions reductions that are attainable using maximum achievable control technology (MACT), consistent with the power plants remaining listed as sources of hazardous air pollutants involving mercury. To date, EPA has not issued MACT standards.

Subsequent to the issuance of mercury emission caps under CAMR, a number of states within the study area, including MD, NJ, MA, CT, NH, and DE, implemented regulations that are intended to achieve a comparable or more aggressive level of reductions. In anticipation of more stringent state and/or potential federal mercury emission limits, coal-fired power plants throughout PJM have initiated mercury emissions control strategies. In Maryland, Phase I of HAA will reduce statewide mercury emissions from coal-fired plants by 80% in 2010, relative to a 2002 baseline. Further reductions are required by 2013. Consistent with the Task 3 Report, we continue to assume that the required mercury reductions from the state's fleet of coal-fired plants will be achieved as co-benefits from the installation of selective catalytic reduction (SCR) and flue gas desulfurization (FGD, or scrubbers) to meet the nitrogen oxide (NO_x) and sulfur dioxide (SO_2) limits under HAA. Mirant has undertaken SCR and/or scrubber retrofit projects at each of its Maryland coal plants to achieve compliance with HAA by 2010.

In order to assess the effectiveness and estimate the costs of mercury emissions controls for coal plants, a number of tests and demonstrations of various control technologies have been conducted by DOE, the Electric Power Research Institute (EPRI), a number of emissions control technology vendors, and several coal-fired power plant operators. These tests have shown that when burning bituminous coals, the combination of FGD for controlling SO_2 emissions, SCR for NO_x control, and particulate control systems can achieve mercury emissions reduction on the order of 90%.[17,18,19,20] Additional testing demonstrated the ability of ACI to achieve high levels of mercury removal when used with only a particulate removal system and significantly higher levels of removal (>90%) when used in combination with FGD and SCR systems.[21]

New MACT rulemaking by the EPA is expected to take several years. The first compliance period may be as early as 2014.[22] Controlling mercury emissions from coal-fired power plants to

[17] "Effects of SCR Catalyst and Wet FGD Additive on Speciation and Removal of Mercury within a Forced-Oxidized Limestone Scrubber," S. Ghorishi *et al*. Babcock & Wilcox Company, C. Teets *et al*. Dominion Generation, and T. Hastings *et al*. Cormetech, Inc., ICAC Clean Air Technologies and Strategies Conference '05, March 2005.

[18] "Mercury Capture and Fate Using Wet FGD at Coal-Fired Power Plants" C.E. Miller et. Al., U.S. Department of Energy, National Energy Technology Laboratory and Science Applications International Corporation, August 2006.

[19] "Control of Mercury Emissions From Coal-Fired Electric Utility Boilers," Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, 2004.

[20] "Enhancing Mercury Control on Coal-fired Boilers with SCR, Oxidation Catalyst, and FGD," Institute of Clean Air Companies.

[21] "Sorbent Injection Technology for Control of Mercury Emissions from Coal-fired Boilers," Institute of Clean Air Companies.

[22] Rossler, Michael, Edison Electric Institute, "Where Now without CAMR?" Proceedings of the 12th Annual Energy & Environment Conference & Expo, February 1-4, 2009, Phoenix, AZ.

meet future MACT standards increases the likelihood that mercury emissions reduction levels of greater than 90% will be required. In the event that the removal rates under MACT are more stringent than achievable with the control technologies installed for HAA, additional capital and operating costs would be incurred by the Mirant plants.

The Base case in this study assumes that emissions control technologies that have been installed on the Mirant coal facilities in response to HAA will achieve sufficient removal efficiency so that the units will also be in compliance with any future federal emissions regulations for mercury, NO_x, or SO_2. The Base case scenarios do not include any additional CapEx or incremental O&M for compliance under a revised CAMR MACT standard.

However, in the event that the EPA issues MACT standards that require greater than 90% mercury removal, we consider a sensitivity case in which the Mirant coal plants are required to install ACI. We assume that under a reasonably fast-tracked rulemaking process, the equipment would need to be installed by 2013 to meet a 2014 compliance date. In this sensitivity case, our financial model has incorporated capital costs of \$3/kW for the installation of ACI, and operating costs of \$3/MWh. The incremental operating cost includes the cost of the sorbent, foregone sales of fly ash for concrete additive, and the additional cost of fly ash disposal. These cost estimates are in the high range of the DOE and EPRI studies, and should be considered conservative.

1.9 SO_2 and NO_x Emission Controls

In response to several challenges that were filed in 2006, on July 11, 2008, the D.C. Circuit vacated EPA's Clean Air Interstate Rule (CAIR), finding several flaws in its construction. CAIR was intended to expand existing controls on NO_x and SO_2 emissions through a cap-and-trade mechanism. On September 24, 2008, EPA filed a petition for rehearing or for remand without vacating the rule. On December 23, 2008, the Circuit reversed itself and remanded CAIR to EPA without vacating the rule because it determined that vacating the rule "would have serious adverse implications for public health and the environment." The Court did not impose a specific deadline for EPA to revise CAIR.

In this study, we continue to assume that EPA will remedy the Court's initial objections to CAIR. All cases utilize a forecast for NO_x and SO_2 emission allowances similar to the forecast utilized in the Task 3 Report, but updated to incorporate the current forward prices.

1.10 Compliance with Clean Water Act 316(b)

Section 316(b) of the Clean Water Act requires that the location, design and construction of cooling water intake structures reflect the "best technology available" (BTA) for minimizing adverse environmental impact. Cooling water intake structures may cause adverse environmental impact to fish, shellfish, larvae or eggs by impingement (being pinned against screens or other parts of a cooling water intake structure) or entrainment (being drawn into cooling water systems and subjected to thermal, physical or chemical stresses). There are three rulemaking phases. Phase II, promulgated in 2004, applied national standards to existing electric generating plants that are designed to withdraw 50 million gallons per day or more and that use at least 25% of their withdrawn water for cooling purposes only.

Entergy, along with several other parties, challenged the Phase II rule in the Second Circuit Court of Appeals. In January 2007, the Court remanded several provisions of the rule. EPA subsequently suspended the Phase II Rule and issued a directive substituting "Best Professional Judgment" for the BTA standard. In April 2008, the Supreme Court agreed to hear the case, but only with respect to whether the EPA has authority under Section 316(b) to weigh the costs and benefits when evaluating the appropriate cooling water intake technology for existing facilities. *Entergy v. Riverkeeper* was argued in December 2008, and a decision is pending.

Absent a stricter federal standard, Maryland's cooling water intake and discharge regulations (COMAR 26.08.03) under its federally-delegated authority remain applicable to large facilities.[23] The state regulations also apply the BTA standard to cooling water intake structures, but do apply a cost-benefit test. The cost-benefit test takes into account the commercial value of the organisms lost to impingement and the adverse impact to the local population of representative important species of aquatic organisms. The Maryland Power Plant Research Program (PPRP), of the Maryland Department of Natural Resources, has conducted studies of the applicability of the BTA standard to power plants in Maryland. PPRP's analyses included the Mirant coal units, which all utilize once-through cooling water systems. All of these facilities had 316(b) demonstration studies conducted in the late 1970s or early 1980s and all were eventually found to be in compliance with Maryland's requirements. In order to attain compliance, some facilities were required to conduct additional studies to determine the extent of their entrainment and impingement impacts and Chalk Point was required to mitigate its impacts. Since the original BTA determinations for these facilities, PPRP has found no basis for reconsideration of those determinations or for requiring additional intake modifications.[24]

Depending on the outcome of the Supreme Court decision in *Entergy v. Riverkeeper*, the BTA standard in Maryland may stand, or the EPA Phase II Rule may become the minimum standard. EPA undertook a technical analysis of the cost of implementing BTA at representative power plants nationwide. These cost estimates were not intended to be complete engineering studies, but were based on generic cost modules to develop compliance costs at model facilities as guidance for developing the final Phase II Rule. The generic compliance projects all involved some type of retrofit to the existing cooling water intake system, such as installation of fine mesh screens. The EPA study results are reported in Table 3.

[23] Maryland rules are applicable to facilities with water withdrawal rates greater than or equal to 10 million gallons per day and less than 20% of the net stream flow at the intake point.

[24] http://esm.versar.com/pprp/316/MD-phase2-proposed-comments.htm

Table 3. Costs Considered by EPA in Establishing Performance Standards for 316(b) Phase II Final Rule[25,26]

Facility	Net Summer Capacity[27] (MW)	Capital Cost	Incremental Annual O&M Cost	Annualized Capital + Net O&M
Chalk Point	683	$6,080,054	$600,880	$1,466,543
Morgantown	1164	$6,410,550	($514,309)	$398,409
Dickerson	546	n/a	n/a	n/a

More stringent interpretation of the BTA standard may require replacement of once-through cooling water systems with closed-loop systems. Mirant has reported to the Maryland Department of Environment (MDE) that its cost estimate for installing a cooling tower for Dickerson is $158 million, plus parasitic load for fans and pumps.[28] In addition, conversion to closed-loop cooling would reduce the efficiency of the plant. A study undertaken by the North American Electric Reliability Corporation (NERC) of bulk power system reliability resulting from Section 316(b) Phase II compliance assumed a 4% reduction in nameplate capacity due to conversion from once-through to closed-loop cooling systems.[29] In this study, NERC examined the effects on installed capacity margins resulting from replacement of once-through cooling water systems with closed-loop systems on all affected power plants in the U.S. NERC concluded that due to retirements and capacity reductions for auxiliary loads and parasitic losses, the U.S. could experience a reduction in capacity margins by 4.3%, from 14.7% to 10.4%. Some regions would be more severely impacted than others. For the ReliabilityFirst Corporation region, which includes Maryland, NERC estimated an installed capacity margin reduction of 2.4%, from 14.5% to 12.1%.

In summary, we have incorporated the most recent data on the rapidly evolving economic and regulatory environment. Since our Task 3 Report, changes in projected economic activity, the estimated cost of capital, future fuel prices, anticipated environmental requirements, forecast electricity demand, planned transmission infrastructure, and the mechanisms for calculating capacity value have all affected the risk-adjusted distribution of EVAs presented in Sections 6 and 7. We have surveyed the best available information and adopted neutral parameters for this study.

[25] EPA, Technical Development Document for the Final Section 316(b) Phase II Existing Facilities Rule. February 12, 2004, EPA 821-R-04-007, DCN 6-0004., Attachment A.

[26] All costs reported in 2002$, amortization period for CapEx of 10 years, and 7% discount rate.

[27] Coal units only. Two steam units at Chalk Point operating on residual fuel oil and natural gas use cooling towers, with make-up water withdrawn from the once-through discharge canal.

[28] Dickerson Generating Station Best Professional Judgment Criteria under Section 316(b) of the Clean Water Act draft report, in review by MDE.

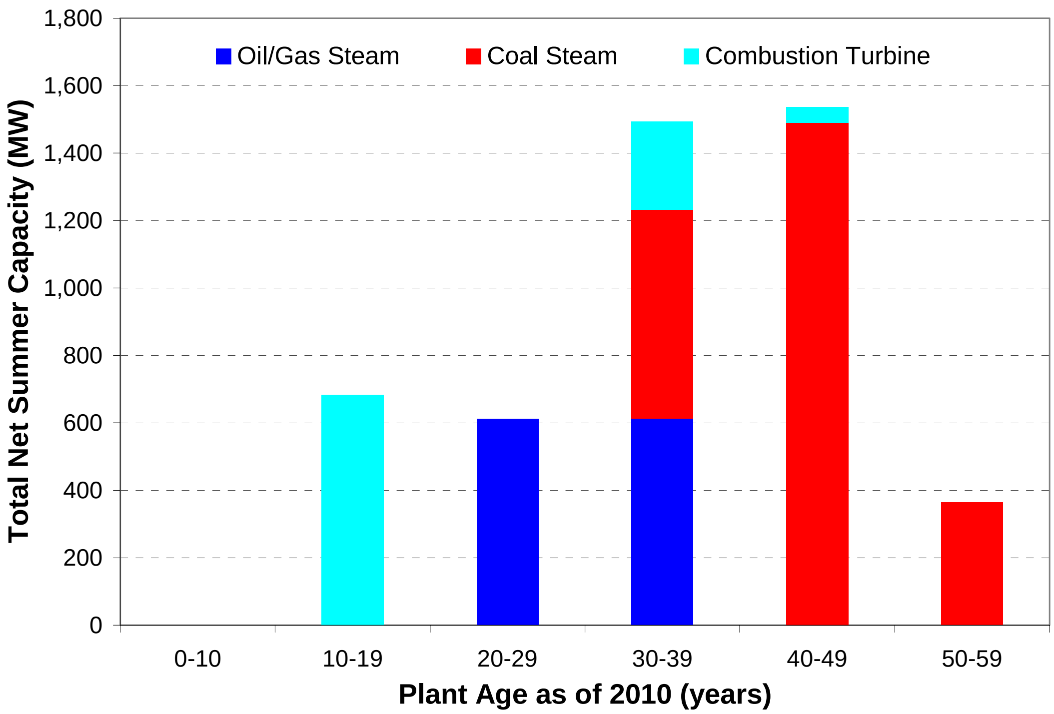
[29] NERC "2008-2017 NERC Capacity Margins: Retrofit of Once-Through Cooling Systems at Existing Generating Facilities," September 2008.

2 MIRANT ASSETS

2.1 Description of Assets

Table 4 lists Mirant's generation assets in Maryland that were acquired from Pepco – a total of 4,690 MW. Other Mirant assets, including plants located elsewhere in PJM, PPAs, and other entitlements, are not included as part of the postulated transaction. As illustrated in Figure 3, the coal units are the oldest assets in the fleet, with most being constructed in the late 1950s and 1960s. Sources of data and assumptions regarding the operating parameters of the Mirant Maryland fleet, O&M, and general and administrative (G&A) costs are described in Sections 8.4 and 8.5 of the Task 3 Report. Unit heat rates have been updated with more recent information available in the MarketSym database. We are not aware of any other material changes in the assets since completion of the Task 3 Report.

Figure 3. Vintage by Technology Type of Mirant Plants



2.2 Ownership History

Mirant (formerly Southern Energy, Inc.) acquired Pepco's generation assets in Maryland and Virginia on December 19, 2000, after Mirant was selected as a winning bidder in Pepco's divestiture process.[30] The net purchase price for these assets was reported as approximately $2.75 billion, which included working capital and CapEx. As part of the acquisition, Mirant also

[30] At the time of the divestiture, Pepco transferred the Benning Road and Buzzard Point generating plants, which were not included in the divested generation assets, to Pepco Energy Services. These power plants are located in Washington, DC, have a total installed capacity of 806 MW, function as exempt wholesale generators, and have third party O&M services.

assumed net liabilities, including transition power agreements and a total of five PPA obligations.

The PPAs were estimated to be a liability of $2.4 billion. For each PPA, Pepco was required to obtain the consent of the counterparty before transferring ownership to Mirant. Pepco was not able to obtain the consent of Panda Brandywine (which was supported by the 230-MW combined-cycle facility in Brandywine, MD), and therefore not able to transfer ownership of the PPA. Mirant and Pepco entered into a "back-to-back" arrangement whereby Pepco would continue to receive the plant's output but Mirant would purchase all of that output and pay Pepco the amount it had owed to Panda Brandywine. By so doing, the PPA between Panda Brandywine and Pepco technically remained in effect, but the economic value of that asset was transferred to Mirant.

According to Mirant's 2000 10-K report, the acquired assets consisted of four generating stations totaling 5,154 MW, three separate coal ash storage areas, a 51.5-mile oil pipeline, and an engineering and maintenance service facility and related assets. In addition to the three Maryland stations shown in Table 4, the transaction also included the Potomac River generating facility located in Virginia. Southern Maryland Electric Cooperative (SMECO) also owns an 84-MW CT co-located with Chalk Point, which operates under a PPA with Mirant. Neither Potomac River nor SMECO are included in transaction postulated in this study.

Table 4. Mirant Assets in Pepco's Maryland Service Territory

	Net Summer Capacity (MW)[31]	Primary, Secondary Fuel	Year In Service	Location (County)	Technology	Full Load Heat Rate (Btu/kWh)[32]
Chalk Point 1	341	Coal, Gas	1964	Prince George's	ST	9,947
Chalk Point 2	342	Coal, Gas	1965	Prince George's	ST	10,399
Chalk Point 3	612	Oil, Gas	1975	Prince George's	ST	11,874
Chalk Point 4	612	Oil, Gas	1981	Prince George's	ST	11,868
Chalk Point CT 1	18	Oil	1967	Prince George's	CT	12,971
Chalk Point CT 2	30	Oil	1974	Prince George's	CT	14,095
Chalk Point CT 3	86	Gas	1991	Prince George's	CT	15,099
Chalk Point CT 4	86	Gas	1991	Prince George's	CT	15,099
Chalk Point CT 5	109	Gas	1991	Prince George's	CT	15,645
Chalk Point CT 6	109	Gas	1991	Prince George's	CT	15,645
Dickerson 1	182	Coal	1959	Upper Montgomery	ST	9,455
Dickerson 2	182	Coal	1960	Upper Montgomery	ST	9,442
Dickerson 3	182	Coal	1962	Upper Montgomery	ST	9,455
Dickerson D CT1	13	DFO	1967	Upper Montgomery	CT	14,079
Dickerson H1 CT	147	Gas	1992	Upper Montgomery	CT	10,168
Dickerson H2 CT	147	Gas	1993	Upper Montgomery	CT	10,168
Morgantown 1	624	Coal, RFO	1970	Charles	ST	9,705
Morgantown 2	620	Coal, RFO	1971	Charles	ST	9,705
Morgantown CT 1	16	DFO	1970	Charles	Frame 5 CT	14,080
Morgantown CT 2	16	DFO	1971	Charles	Frame 5 CT	14,080
Morgantown CT 3	54	DFO	1973	Charles	Frame 7 CT	11,711
Morgantown CT 4	54	DFO	1973	Charles	Frame 7 CT	11,711
Morgantown CT 5	54	DFO	1973	Charles	Frame 7 CT	11,711
Morgantown CT 6	54	DFO	1973	Charles	Frame 7 CT	11,711
Total	4,690					

[31] 2007 PJM 411 Report
[32] Data from Ventyx in MarketSym database.

2.3 Environmental Compliance

2.3.1 Maryland HAA

HAA requires Mirant to address NO_x, SO_2, and mercury emissions from each of its coal-fired power plants. Compliance dates and limits for NO_x and SO_2 are shown in Table 5.[33] To achieve these reductions, Mirant has installed two SCR units at Morgantown and one at Chalk Point. These systems are expected to reduce NO_x emissions by approximately 70-90%.[34] The additional load required to run the SCR system is approximately 0.5% of the net generation capacity of the unit.

Table 5. Emissions Limits Based on HAA

Emission	NO_x	NO_x	NO_x	NO_x	SO_2	SO_2
Implementation Year	2009	2012	2009	2012	2010	2013
Tonnage Limit	by year	by year	by ozone season	by ozone season	by year	by year
Chalk Point 1	1415	1166	611	503	3403	2606
Chalk Point 2	1484	1223	655	542	3568	2733
Dickerson 1	672	554	311	257	1616	1238
Dickerson 2	736	607	333	274	1770	1355
Dickerson 3	698	575	314	259	1678	1285
Morgantown 1	2540	2094	1053	868	6108	4678
Morgantown 2	2522	2079	1048	864	6066	4646
Totals	10067	8298	4327	3567	24209	18541

Mirant also intends to install FGD emissions controls, along with associated equipment, handling and storage facilities to control SO_2 at Chalk Point, Dickerson and Morgantown by 2010. The FGD and SCR systems provide a co-benefit of reducing emissions of mercury. The layout of the FGD system was designed to allocate space for a fabric filter baghouse and powdered ACI equipment, if needed to comply with future mercury control requirements.

Mirant's estimate for the total CapEx to achieve compliance with HAA and other regulatory requirements is $1.8 billion through 2010, as shown in Table 6. Costs through 2009 are considered sunk and not used in the current analysis. The CapEx budget also includes installation of upgraded coal pulverizers on Morgantown Units 1 and 2 and Dickerson Units 1-3 in order to be able to burn lower sulfur coals and achieve fuel flexibility.

[33] *Environmental Review of the Air Pollution Control Project at the Morgantown Generating Station,* June 2008.

[34] *Environmental Review of the Proposed Selective Catalytic Reduction (SCR) System Project at the Chalk Point Generating Station,* March 2008.

Table 6. Capital Expenditures by Year ($ Millions)

Year	Expenditures
through 2006	80
2007	573
2008	689
2009	286
2010	125
Total	1,753

2.3.2 Water Use and Discharge

Morgantown – Water is withdrawn from the Potomac River for once-through cooling in Units 1 and 2 and for process water. Under the facility's permit, the plant may withdraw a daily average of 1.5 billion gallons on a yearly basis and a maximum daily quantity of 2.4 billion gallons. As noted in Section 1.10, the PPRP determined that the plant meets state requirements for BTA under 316(b), primarily due to a curtain wall in front of the intake. Morgantown also has permits for groundwater withdrawal from several wells throughout the site. The station discharges cooling water, clean stormwater runoff, and treated process and wastewater under an EPA permit to the Potomac River and Pasquahanza Creek. Cooling water discharge was determined by the MDE to comply with the state's thermal mixing zone requirements.

Chalk Point – Water is withdrawn from the Patuxent River for once-through cooling and associated process water for coal-fired Units 1 and 2. Chalk Point complies with state 316(b) requirements by using barrier nets and by operating an aquiculture center at the station. Oil-fired Units 3 and 4 utilize natural draft cooling towers and obtain makeup water from the discharge canal of the once-through system. Chalk Point also has permits to withdraw water from groundwater wells for potable supplies, sanitary facilities, boiler make-up, pollution control, and for cooling water. The station discharges cooling water into a canal that empties into the Patuxent River. The MDE determined that the discharge from Units 1 and 2 did not meet thermal discharge limits, and has required Chalk Point under its discharge permit to conduct long-term monitoring of fish and shellfish.

Dickerson – Water is withdrawn from the Potomac River for once-through cooling, air pollution control, and ancillary uses at Units 1-3. The PPRP determined that there was no cost-effective technology to reduce fish impingement since the cost of the technology would exceed five times the annual value of the fish. The station also has permits for withdrawal of water from wells for potable and non-potable supplies. The station discharges cooling water, clean stormwater, and treated process and wastewater to the Potomac River and the Chesapeake & Ohio canal. The MDE determined that the discharge from Dickerson did not meet thermal discharge limits, and has required the station to conduct biological monitoring under the terms of its discharge permit.

2.3.3 Solid Waste

Fly ash and bottom ash are the two products produced by coal combustion. Ash is utilized on site for roadway maintenance, sold to outside parties, or trucked to off-site ash storage sites.

Under federal regulations, coal combustion products are not considered hazardous waste. For the purposes of this analysis, we consider a federal rule change that would regulate coal ash as hazardous to be highly unlikely. If a coal plant were required to install ACI, we assume that the ash could no longer be sold for beneficial use but could continue to be disposed of at a permitted ash storage facility.

3 FINANCING OPTIONS AND TRANSACTION STRUCTURE

3.1 Acquisition by IOU

In Section 2.5.3 of the Task 3 Report, we explained our assumption that an IOU (such as Pepco) would be able to finance the acquisition of the Mirant assets on-balance sheet using its existing 50/50 debt/equity structure, a standard capital structure that is consistent with many utilities that are vertically integrated as well as those that have divested their generating assets. In the Task 3 Report, we also assumed that an IOU would be able to issue 20- to 30-year debt at a 7.0% interest rate and that the cost of equity (allowed return on equity) would be 10.5%. We made explicit our "simplifying assumption that the capital markets will trend towards normalcy in the next two years, reflecting a more typical and stable long-term financial environment of the capital markets prior to the sub-prime meltdown."

The only factor that has changed since last December is the long-term inflation outlook, as described in Section 1.1.2 of this report. Since our inflation assumption has dropped from 2.5% per annum to 2.0%, we have also reduced Pepco's cost of debt and equity funds by 0.5% to keep our financing assumptions consistent on a real basis. Thus LAI is assuming that Pepco would be able to finance the acquisition of the Mirant generating assets 50/50 with 30-year debt at a 6.5% interest rate and a 10.0% cost of equity.

Whether Pepco or PHI acquires the Mirant assets, their financial condition has not materially changed in the past few months.[35] As of mid-February 2009, PHI had BBB / Baa3 / BBB (S&P / Moody's / Fitch) credit ratings that have not changed since 2006.[36] Pepco had BBB / Baa2 / BBB+ credit ratings that have also not changed since 2006.[37] Thus, our IOU financing assumptions have not been altered except for the underlying inflation rate.

3.2 Acquisition by State Power Authority

In Section 2.5.3 of the Task 3 Report, we explained our assumption that a new state power Authority, established by the statute, would be able to finance the acquisition of the Mirant assets by issuing long-term revenue bonds that are exempt from state income tax but not federal income tax. We presented our assumptions about tax status, debt cost, and other facets based on financial data for the Maryland Transportation Authority (MdTA) and various municipal bond issuances. We concluded that the new Authority would have a credit rating in the AA/Aa range, consistent with the MdTA, and that a 6.1% average interest rate was reasonable assuming that interest payments for MdTA debt were fully tax-exempt, while interest payments for Authority debt would only be exempt from Maryland state income taxes.

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[35] It may be possible for PHI, Pepco's parent, to establish a separate regulated generation company to own and operate the Mirant fleet in Maryland. Relative to Pepco, PHI is a much larger company and may therefore be better able to absorb the Mirant assets. According to the most recent SEC 10-Q financial data (as of September 30, 2008), PHI was a $15.6 billion firm in terms of assets, relative to $4.5 billion for Pepco.

[36] S&P and Moody's downgraded PHI one notch from BBB+ / Baa2 in 2006.

[37] S&P and Moody's downgraded Pepco one notch from BBB+ / Baa1 in 2006; Fitch downgraded Pepco one notch from A- in 2005.

We see no reason to alter the expected cost of debt for an Authority except for the reduction in the long-term inflation rate of 0.5%. As noted in the Task 3 Report, the MdTA, which also issues Revenue Bonds, is a better starting point for estimating the cost of 30-year debt than the State of Maryland, which issues GO bonds backed by the full faith and credit of the State. Thus we have assumed that a power Authority would be able to issue 30-year debt at a 5.6% average interest rate.

3.3 Transaction Costs

In the Task 3 Report we did not explicitly include any transaction costs for an IOU or for a new Authority to acquire the Mirant generating assets. We recognize that the acquirer would incur significant transaction costs for legal counsel, accounting, appraisals, financing fees, commercial and technical consulting reviews, and other due diligence / transaction tasks. We are familiar with other acquisitions and large financial transactions, and believe that such transaction costs could be $20 million for a merchant generation company to prepare and submit a bid under a competitive divestiture process, conduct commercial and technical due diligence, engage outside counsel (on a limited scale), and complete the acquisition.

Transaction costs for Pepco / PHI could be much higher than the merchant estimate, roughly $30 million, to cover incremental legal fees to amend corporate documents and mortgage indentures, participate in condemnation proceedings, and conduct other necessary steps to accommodate ownership and operation of a new group of generating assets. Debt and equity issuance costs would be responsible for another $6 to $15 million for issuance / floatation costs, underwriter's discount, and other necessary fees.[38] A new Authority would incur additional legal fees to establish a full set of by-laws and other required documents, so we estimate a higher transaction cost of $40 million, as indicated in Table 7. A discussion of condemnation risks and uncertainty factors is provided in Section 8.

Table 7. Study Assumptions for Transaction Costs

Merchant	Pepco / PHI	Power Authority
$20 million	$30 million	$40 million

3.4 Transitional Risks and Costs

In the Task 3 Report, LAI identified, but did not quantify, the myriad risks and costs to transition from a competitive power generation market to rate base regulation of generation assets. We mentioned that the "…many complex and interrelated policy, legal, regulatory, and economic constraints…may be time consuming and potentially costly, and therefore may affect the EVA analysis…" The acquirer will have to ensure a smooth transition in the operation of the generating assets, and retain virtually the entire O&M staffs at the plants. In this study we

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[38] A February 27, 2008, offering memorandum for $400 million on State of Maryland GO Bonds had issuance costs of just over $1.2 million, equivalent to 0.3% of the total issuance proceeds. Scaling these issuance costs up to, say, a $5 billion issuance would imply costs of $15 million.

quantify some of the primary transitional costs if Pepco / PHI or a new Authority were to acquire the Mirant generation assets in Maryland.

3.4.1 Transitional Risks and Costs – Organizational Structure

In order for Pepco / PHI to absorb the Mirant generating assets, the company's organizational structure would have to be radically altered and expanded to incorporate the new generation function as well as all of the associated headquarter functions of fuel supply, supplies and stores management, operator training and safety, risk management, *etc*.[39] For an Authority, establishing and staffing a new organization structured around the demands of operating the generation assets would constitute a major challenge. This effort would require the assistance of outside services to formulate an organizational structure, hire appropriate personnel, establish operating practices and procedures, establish relationships with outside entities (PJM, fuel suppliers, vendors, maintenance contractors, *etc*.), and operate in parallel with Mirant prior to the actual turnover of generating assets.

We assume that all plant O&M staff would be retained in an acquisition, so only management functions would have to be established. While the vast majority of plant staff typically continue to work for a new owner when generation assets change hands, retaining the trained and knowledgeable plant O&M staff cannot be guaranteed. Regarding headquarters functions, Pepco / PHI would have to broaden the capabilities of many existing departments such as treasury, accounting, legal, *etc*., to accommodate the needs of the generation business. While some of these functions could be temporarily outsourced, such a strategy only delays the inevitable cost and effort of establishing those functions internally.

The incremental cost of expanding the existing Pepco management organization is material. Whether there are more efficient ways to "leverage" the existing PHI management structure in the context of acquiring and then managing the Mirant fleet has not been part of this inquiry. As discussed in Section 3.4.2, in deriving the cost of expanding the Pepco organization in order to ensure successful operational and financial performance, we have not assumed any operational synergies with PHI management.

Based on the above concerns, LAI assumes that an Authority would incur greater transition costs than Pepco / PHI. We estimate one-time Authority transition costs at $25 million, equal to 6 months worth of our estimate of annual G&A expense (to cover headhunter fees, compensation prior to turnover, and outside services to establish practices and procedures). Pepco / PHI would incur much lower transition costs that we estimate at $10 million, equal to 3 months of estimated G&A expenses. Transition costs would be negligible for a merchant generator that already has a fully functional organization in place.

[39] We recognize that Pepco has retained Benning Road and Buzzard Point, but we have assumed that Pepco did not retain the full compliment of generation and related function staff that would be required if the Mirant generating assets were purchased.

3.4.2 Transitional Risks and Costs – G&A Expenses

Regardless of Pepco / PHI or Authority ownership of the Mirant assets, a new management organization would have to be created that includes all of the typical headquarters functions for a generation entity. To estimate the G&A expenses associated with the Mirant asset acquisition by Pepco / PHI or an Authority, LAI reviewed three data sources: historical Pepco G&A expenses, management staffing and cost data for the New York Power Authority (NYPA) and the Long Island Power Authority (LIPA), and Mirant's reported G&A expenses.[40]

3.4.2.1 Pepco G&A Expenses

LAI evaluated the historical G&A expenses reported by Pepco in its FERC Form 1 for 2000 when Pepco owned the Maryland assets. Pepco reported total G&A expenses of $85.7 million for 1999 and $96.7 million in 2000, of which power production accounted for $38.4 million and $41.3 million, respectively. We believe these values serve as a reasonable starting point, which when escalated to 2008 provides us with an estimated G&A expense of $50 million on a stand-alone basis (without synergies from existing generation activities).

3.4.2.2 NYPA and LIPA G&A Expenses

As of year-end 2007, NYPA had $7.0 billion in assets and $2.9 billion in revenues, and owned 6,635 MW of generation. In its *2008-2011 Approved Budget and Financial Plan 2008-2011*, NYPA planned to have the following approved employee positions in 2008 by functional area: 616 for headquarters, 809 for power generation, and 206 for transmission. According to this same report, total compensation (salaries plus benefits) for these employees was $193.1 million in 2008, divided between $140.3 million in salaries and $52.8 million in benefits. This report also indicated that total headquarters expenses would be $79.3 million (out of total O&M expenses of $295.2 million).[41] This yields an average annual headquarters compensation plus miscellaneous expenses of roughly $129,000 per employee. NYPA's budgeted headquarters expenses of $79.3 million represent 3.0% of NYPA's budgeted total operating expenses of $2,619 million.

As of year-end 2007, LIPA had $10.9 billion in assets, $3.5 billion in revenues, and owned 6,690 MW of generation. In its *2008-2012 Approved Operating Budget*, LIPA announced they had 103 approved employee positions, all of which were for headquarters. These headquarters positions included the office of the president and the most senior managers in communications, customer relations, finance, human resources, legal, power markets, and other administrative positions. No other staff positions were identified, as LIPA outsources most of its management staffing requirements for engineering, legal, financial, accounting, insurance, and other functions under a professional services agreement.

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[40] NYPA and LIPA were described in Section 2.5.2 of the Task 3 Report.

[41] NYPA's budgeted O&M expenses of $295.2 million for 2008 are consistent with its actual 2007 O&M expenses as reported in its 2007 *Financial Report*, which lists O&M expenses of $501 million; when voluntary contributions to New York State of $205 million are subtracted, the resulting value is $296 million.

According to the LIPA budget document, total compensation for the 103 headquarters employees in 2008 was $16.1 million, including $10.5 million in salaries and $5.6 million in benefits. This yields an average annual expense of roughly $155,000 per employee, slightly higher than the NYPA value. In order to estimate the additional LIPA management staff provided through the professional services agreement, we relied on LIPA's 2008 budget which lists an additional $24.0 million for professional services and general expenses for an estimated total of $40.1 million for management functions at LIPA's headquarters. Assuming the same average compensation for outsourced staff, this implies total management staff equivalent of 256 personnel.

Table 8 compares NYPA's and LIPA's headquarters' staffing and expenses. We estimate the total cost of management functions for a new Authority at $50 million and for Pepco / PHI at $40 million, derived as follows:

- Assuming FMV of approximately $5 billion for the Mirant assets, the management staff and costs for NYPA and LIPA provide a reasonable estimation basis due to their similarity in function and financial size. Table 8 provides asset sizes and annual revenues (estimated for Pepco and the Authority).
- We believe the NYPA staff of 616 includes various retail, transmission, and hydroelectric functions that would not be required for the Mirant generation assets, and is too high. On the other hand, the estimated equivalent LIPA staff of 256 cannot be relied upon because so many are outsourced, and may be too low. Therefore we expect that an Authority would require about 400 management staff, a midpoint value, and that Pepco / PHI would require about 20% fewer incremental management staff. While Pepco already has many functions required for the generation business, the acquisition is so large relative to Pepco's existing size that most functions would have to be expanded significantly.
- We estimate average compensation at $125,000, slightly lower than NYPA because of lower living expenses in Maryland. The average LIPA compensation is probably biased high because it probably includes a relatively high percentage of internal senior-level positions, while relatively more mid-level and lower-level management positions are outsourced at lower compensation levels.

Table 8. Estimated Annual G&A Expenses for Pepco / PHI and Authority

	NYPA	**LIPA**	**Pepco / PHI**	**Authority**
Assets	$7.0 billion	$10.9 billion	$5 billion	$5 billion
Revenues	$2.9 billion	$3.5 billion	$2.0 billion	$1.7 billion
Management Staff	616	256 [42]	320	400
G&A per Staff	$129,000	$155,000	$125,000	$125,000
Total G&A	$79.3 million	$40.1 million	$40 million	$50 million

[42] Includes estimated G&A staff under Professional Services Agreement.

3.4.2.3 Mirant G&A

As a check to our G&A estimate, we reviewed Mirant's financial statements in its Form 10-K for 2000 and 2001 to see if there was any relevant data that identified an increase in G&A after acquiring Pepco's generating assets in December 2000. While Mirant's G&A expenses increased materially, it is impossible to discern how much of that increase was due to the acquisition as opposed to other corporate changes, such as acquiring an 80% interest in the Jamaica Public Service Company, incorporating the operations of an Energy Marketing affiliate, and other provisions.

We also reviewed the most recent financial statement in the 2007 Form 10-K for Mirant North America, the Mirant subsidiary that currently owns its North American generating assets. We found that Mirant NA incurred $152 million of "management, personnel, and other services," plus $125 million in administrative overhead expenses. Mirant NA's Mid-Atlantic business segment accounts for $144 million of these expenses, and since the Maryland assets account for almost 91% of Mirant NA's Mid-Atlantic assets, this implies roughly $130 million of annual management and overhead expenses. We are concerned that the Form 10-K data is incompletely defined and the business functions are not identified, so we are reluctant to base our G&A estimate on the Mirant NA data. However, we consider Mirant's much higher management and overhead expenses in our probabilistic analysis in Section 6.3.

3.4.2.4 LAI Study Assumptions

The escalated G&A value of $50 million from Pepco's FERC Form 1 is entirely consistent with our independent G&A estimates based on NYPA and LIPA data. For FMV purposes, we assume that a merchant generation acquirer would already have G&A that is fully staffed and functioning, and thus would only incur incremental G&A expenses of $20 million. The G&A values that we adopt for this assignment are summarized in Table 9.

Table 9. Study Assumptions for Transition Cost and G&A and Bank Facility Expenses

	Merchant	**Pepco / PHI**	**Authority**
Transition (one time)	$0 million	$10 million	$25 million
G&A (per year)	$20 million	$40 million	$50 million
Bank Facility (per year)	$10 million	$10 million	$10 million

3.4.3 <u>Transitional Risks and Costs – Short-Term Bank Facility</u>

Virtually all power generation companies have risk management departments that are responsible for providing credit in the form of unconditional corporate guaranties and security in the form of cash or irrevocable standby letters of credit (LCs) required by PPAs and other contracts. It is common for counterparties to require or provide credit or security based on marking-to-market contracts against standardized power market indices. In addition, virtually all power generation companies have significant working capital requirements to fund periodic expenses for fuel, payroll, materials, and other short-term needs. Thus Pepco / PHI or an Authority would require a revolving credit facility, perhaps in addition to other short-term bank debt, to provide cash and LCs required by contractual commitments and to fund working capital. These types of bank facilities typically have interest rates tied to LIBOR or another daily inter-bank rate. We estimate the cost of establishing a revolving credit facility at 1.25% of the nominal facility size under normal credit conditions.

In order to estimate the size of an appropriate revolving credit facility for the acquirer of the Mirant generating assets, we reviewed Mirant's short-term bank facilities. Mirant has $1.5 billion in short-term bank facilities (an $800 million senior secured revolving credit facility and a $700 million senior secured term loan) that it uses to provide cash and LC security, working capital, and other cash requirements. Mirant had $38 million of cash collateral and $204 million of LCs outstanding at year-end 2006, and $108 million of cash collateral and $290 million of LCs outstanding as of year-end 2007. As a competitive wholesale generation company, the Maryland assets comprise about 50% of Mirant's assets, revenues, and gross margin. Thus, we estimate that an appropriate revolving credit or other short-term bank facility would be sized at 50% of Mirant's combined facilities, or $750 million, and that the annual fee for such facility would therefore be close to $10 million (2008$).

4 SCENARIOS AND PRIMARY MARKET VARIABLES

Formulation of the risk adjusted distribution of financial outcomes associated with the return to rate base regulation has required the definition of multiple scenarios covering plausible combinations of primary variables affecting wholesale energy prices in Maryland. The primary variables include fuel prices, environmental policy affecting climate change, and the economy, in particular, the impact of the recession on load growth. This scenario-based approach has been used as the foundation for the analysis used to support the value of the Mirant fleet under FMV as well as the range of consequent potential economic outcomes under either Pepco or Authority ownership.

In order to quantify the risk-adjusted distribution of financial outcomes, LAI has first conducted a deterministic analysis of the value of the Mirant assets. This valuation encompasses the array of assumptions investors would be most likely to use to project cash flows from the sale of capacity, energy and ancillary services over the valuation period. The first analysis method is a deterministic estimation of FMV of the Mirant fleet under the Base scenario. The values of key factor inputs are described more fully in this section. The second analysis method considers all seven scenarios in separate, deterministic estimates of ratepayer impact. Details about the scenario formulation and study assumptions used in the second analysis are provided in this section. The third analysis, described in Section 6, uses probability distributions and Monte Carlo simulation techniques across the array of scenarios formulated by LAI.

Monte Carlo analysis is a relatively conventional financial evaluation method used by investors in capital-intensive industries in order to compute value-at-risk (VaR). Random sampling of key uncertainty variables allows for the derivation of probability-weighted EVAs. Using this statistical modeling technique, LAI has produced various measures of dispersion around the expected EVA in order to reveal the probability and magnitude of risk that Pepco's ratepayers would be exposed to on the downside, as well as the potential opportunity on the upside.

4.1 Primary Uncertainty Factors and Scenario Definitions

Seven scenarios have been formulated to capture the uncertainties in key variables – market, economic, infrastructure and regulatory assumptions – that are the primary drivers underlying the value to load in Maryland associated with the return to rate base regulation. The scenarios represent discrete, internally consistent views of potential energy futures in both Maryland and PJM. Each scenario corresponds to a separate run in MarketSym, the production simulation model used to forecast locational marginal prices (LMPs) across PJM, and the direct link between energy prices and capacity prices derived in the capacity price model. Project net cash margins from energy sales coupled with the operating income derived from the sale of capacity and ancillary services provide the revenue streams of relevance over the 20-year valuation period. The resultant EVA for each scenario has been computed, representing the present value differential between what Pepco's ratepayers would otherwise pay under the existing PJM market design versus the return to rate base regulation.

The seven scenarios have been labeled "S1" through "S7," as indicated in Table 10. The top block of blue shaded cells illustrates the concept that the scenarios represent distinct combinations of two primary economic drivers: global oil prices and anticipated federal policy on GHG controls. We have assumed that the GDP growth rate is correlated with global oil prices; hence, we consider these two variables together, *i.e*., low economic growth corresponds to low global oil prices, and *vice versa*. These two primary economic variables underlie the other factors that are necessary inputs to MarketSym: PJM and Maryland load forecast, the delivered price of both residual fuel oil and distillate, natural gas, coal, and the price of CO_2 emissions allowances. Because energy margins vary by scenario, variances in operating revenue associated with capacity sales are likewise differentiated by scenario. The primary variables also impact the quantities of new capacity resources and attrition of existing resources. Relative to the Task 3 Report, all transmission topology assumptions are the same except one: whereas TrAIL had been added to the region's total transmission supply in 2014, in this study, we have added TrAIL and various downstream transmission improvements in SWMAAC to the transmission infrastructure of the region in 2011.

In developing the scenarios, we have considered two different federal GHG policies and four different outlooks on global oil prices. The combination of four oil price forecasts and two federal climate policies results in up to eight possible scenarios. For purposes of the probabilistic model, however, only six scenarios are needed to adequately determine the distribution of EVA outcomes.[43] The yellow shaded cells in Table 10 summarize the input parameters that are used to construct the seven scenarios. The FMV of the Mirant assets is based on the Base scenario, S1.

[43] The Peak Oil / Strict Cap combination, as shown by the cross-hatched cells in Table 10, was not modeled as a separate scenario because it is considered highly improbable.

Table 10. Scenario Matrix

Energy Market Simulation

		General Economic Conditions			
	Oil Prices	**Low**	**Base**	**High**	**Peak**
	GDP Growth	**Low**	**Base**	**High**	**High**
Federal Climate Policy	**2014 Moderate Cap**	**S3**	**S1**	**S2**	**S7**
	2012 Strict Cap	**S6**	**S4**	**S5**	

Fuel Price Forecast

Federal Climate Policy	2014 Moderate Cap	IEO Low Oil Price Case	NYMEX & EIA 2008 IEO Reference Case	IEO High Oil Price Case	LAI Peak Oil Price Case
	2012 Strict Cap	S3 Oil & Coal, higher NG	S1 Oil & Coal, Higher NG	S2 Oil & Coal, Higher NG	

Load Forecast

Federal Climate Policy	2014 Moderate Cap	Lower than S1	PJM 2009 Forecast	Higher than S1	Same as S2
	2012 Strict Cap	Slightly lower than S3	Slightly lower than S1	Slightly lower than S2	

Resource Mix

Federal Climate Policy	2014 Moderate Cap	Less new capacity than S1 (same renewables)	LAI analysis of economic mix	More new capacity than S1 (same renewables)	Same as S2 but more renewables and DSM
	2012 Strict Cap	Add CC3, more NG and renewables, retire some coal v. S3	Add CC3, more NG and renewables, retire some coal v. S1	Add CC3, more NG and renewables, retire some coal v. S2	

4.2 GHG Policy and CO_2 Allowance Price Forecast

As discussed in Section 1.2, we believe that there is little doubt that Congress will enact some form of climate change legislation by 2010. We continue to assume that federal GHG controls will be implemented in the form of a cap-and-trade program for CO_2, and a federal allowance market will subsume the RGGI market and other regional initiatives. However, among other uncertainties, it is premature to gauge with any reasonable accuracy what the target GHG reductions may be, what sectors of the economy will be subject to the legislation, when the first compliance period will begin, how allowances will be allocated and/or auctioned to the regulated entities, how revenues from the sale of allowances will be applied, what mechanisms will be incorporated to ensure reliability of the grid, or whether international trading will be allowed. Therefore, there is little hard information on which to build a model to forecast GHG allowance prices. However, the expected level of allowance prices is a major consideration in passing the legislation and the only consideration that this analysis needs to consider. Regardless of GHG control policy details, fuel prices and electricity prices will be impacted similarly for a given market price per CO_2 allowance.

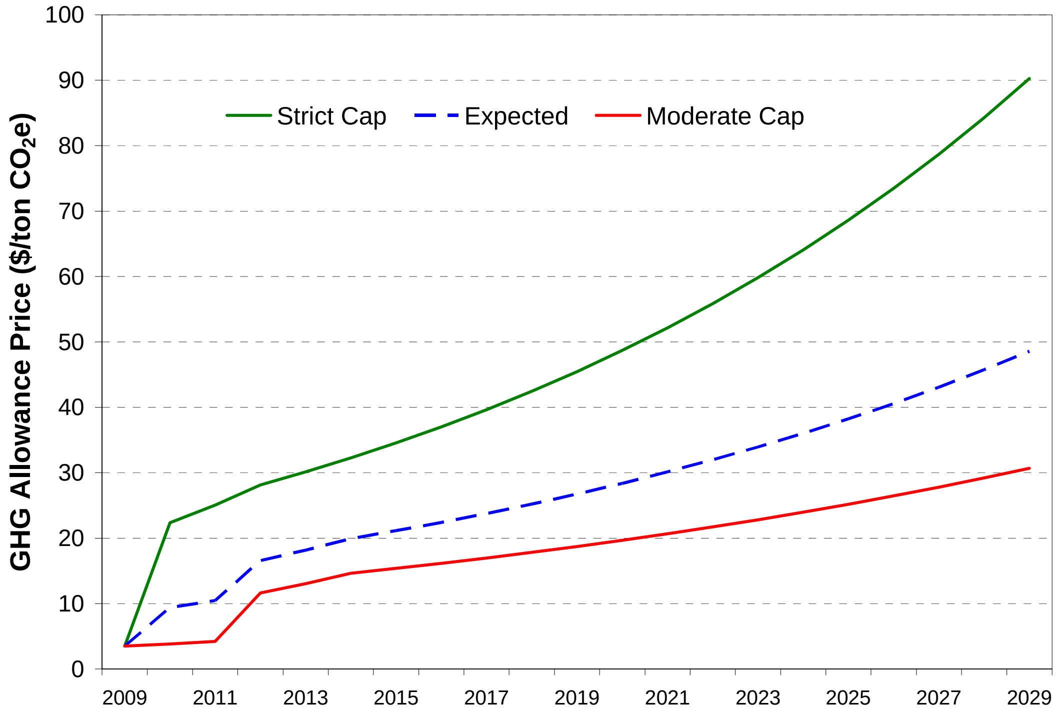
LAI has compared a number of studies which modeled alternative GHG cap-and-trade policy rules and reported results for CO_2 allowance market prices, electricity prices, fuel prices, and GDP under scenarios similar to those proposed in various bills in Congress. Forecasts of CO_2 allowance prices vary widely. For the scenario analysis, we have postulated two CO_2 allowance price projections that bracket the likely range of outcomes regarding implementation of a federal GHG control policy: the "Moderate Cap" and the "Strict Cap" forecasts.

In the "Moderate Cap" forecast, we postulate that the first compliance year of a federal program will be 2014, although forward trading of CO_2 allowances in anticipation of a federal allowance market will occur. Prices of CO_2 allowances will be mitigated by establishing a less stringent cap and "safety valve" features such as use of offsets, *e.g.*, credit for investments such as reforestation projects that permanently reduce GHG emissions.

In the "Strict Cap" forecast, we assume that GHG controls will be pursued on an expedited basis, and more stringent compliance rules will be implemented. The first compliance year will be 2012, and a tighter cap and/or less flexible use of offsets will result in the price of CO_2 allowances being higher than in the Moderate Cap forecast.

LAI's long range CO_2 allowance price forecasts are presented in Figure 4. The Moderate Cap forecast, applicable to S1, S2, S3, and S7, is near the low end of the price range resulting from numerous published GHG policy model studies. The Strict Cap CO_2 allowance price forecast, applicable to S4, S5, and S6, is near the high end of the same set of studies. The wide variation in the Moderate Cap and Strict Cap CO_2 allowance price projection cases is due to differences among models, data, and assumptions used across these GHG policy studies, as well as substantial differences in the degree of control of GHG emissions assumed. The smoothly growing price forecasts after introduction of the federal GHG program reflect the ability to bank and draw allowances between years, as well as possibly escalating safety valve prices. With banking and drawing, the scarce GHG allowances would be expected to grow in price equal to the rate of interest on financial investments. The Moderate Cap case assumes the first-year price is $12/ton (2009$) in 2014 and that real prices grow 3% thereafter. The Strict Cap case assumes the first-year price is $24/ton (2009$) in 2012 and that real prices grow 5% thereafter. Both cases assume that for the two years prior to the start of the federal GHG allowance trading program, RGGI allowance prices rise due to the federal program allowing exchange of RGGI allowances for federal allowances on a 1:1 basis. LAI assumes that the expected price is equivalent to weighting the Moderate Cap CO_2 price projection at 70% probability and the Strict Cap case projection at 30%, also shown in Figure 4.

Figure 4. CO_2 Allowance Price Forecast



Both forecasts start with allowance prices in 2009 that are generally consistent with the two recent RGGI auctions and NYMEX futures. The Moderate Cap forecast assumes that allowance prices increase slowly over the first few years of the regional cap-and-trade program, when the costs are applicable to the RGGI states only.

As a point of reference, the Moderate Cap allowance price forecast is similar to the second (level 2) of four GHG cap levels simulated by EIA with its detailed National Energy Modeling System simulation tool. The Strict Cap outlook corresponds closely to the most stringent (level 4) of the four control cases EIA analyzed. EIA selected this range of possible caps to bracket the range of GHG control legislation under consideration at the time. In EIA's level 2 cap-and-trade case, resulting allowance prices were low enough that coal generation would continue to increase over time, but at a slower rate than in EIA's reference case, which does not model a federal GHG cap-and-trade system. Level 2 case prices tended to result largely in a switch from coal to natural gas generation. In contrast, level 4 case prices were sufficiently high to significantly reduce generation across all fossil fuels.[44]

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[44] The level 4 cap-and-trade case coal generation in 2030 is only 39% of EIA's reference case value while the level 2 coal generation is 76% of the reference level. Natural gas generation in 2030 in the level 2 case increases 50% over the reference level while level 4 natural gas generation increases only 13%. Total fossil fuel generation (coal, oil, natural gas) in 2030 in the level 2 case is 82% of the reference case level, while the level 4 case fossil fuel generation is only 48%. See EIA, *Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals*, March 2006, SR/OIAF/200601.

4.3 Fuel Price Forecast

Rapidly changing market dynamics cloud the outlook for fuel prices delivered to power plants across PJM. As explained in Section 1.3, the global recession, changes in the U.S. natural gas supply outlook, and pending federal GHG controls have combined to materially reduce the long-term trajectory of oil and delivered natural gas prices relative to the *Conventional Wisdom Scenario* in the Task 3 Report. The correction from the top of the market in the summer of 2008 to the recent trough in commodity prices has been over 70%. To capture the range of uncertainty in fuel prices over the study horizon, we have utilized four discrete fuel price forecasts to capture the range in delivered fuel prices under the Moderate Cap scenarios, S1, S2, S3 and S7. In these scenarios, we assume the *status quo* GHG policies in the EU, an anticipated "moderate" U.S. cap-and-trade system, and possible expansion of GHG controls in other countries. The fuel price forecasts incorporated in S4 through S6 reflect "strict" cap assumptions. Hence, for these scenarios we have incorporated adjustments to reflect the market reaction to more stringent GHG controls.

4.3.1 Fuel Forecasts for S1, S2, S3, and S7 (Moderate Cap Scenarios)

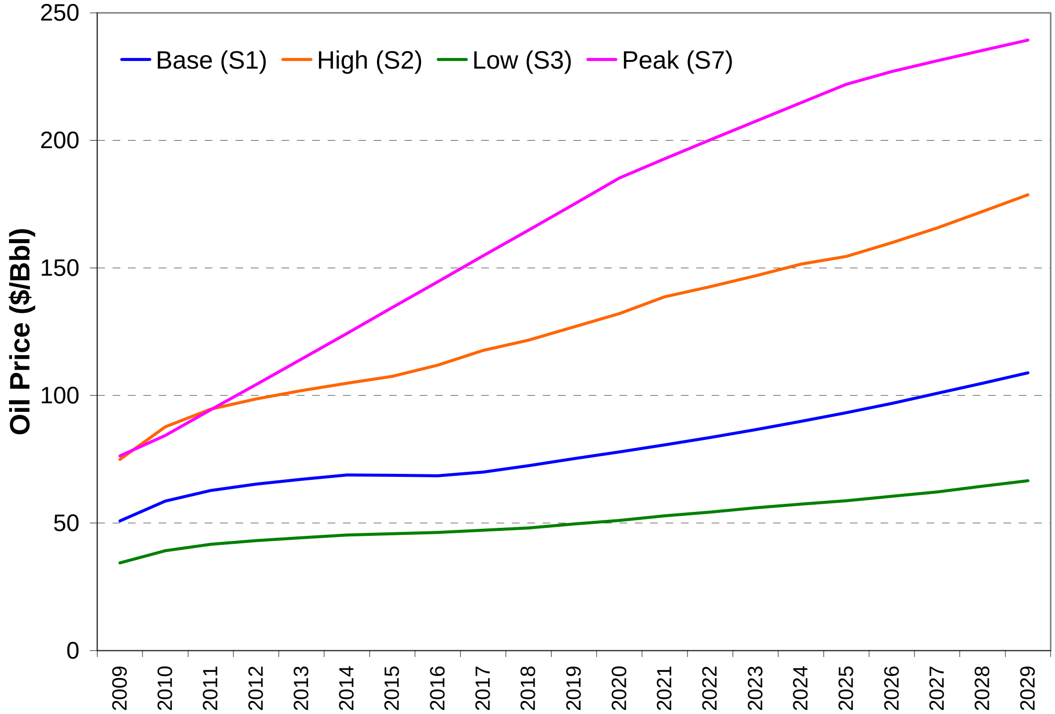
EIA's 2008 IEO projections of world oil prices form the basis for the long-term (2015 onward) portion of the fuel price forecasts in S1, S2, and S3. Issued in June 2008, this forecast is generally consistent with recent long-term market expectations. S1, the Base scenario, reflects the Reference Case of the 2008 IEO and is generally consistent with the *Federal Outlook Scenario* presented in the Task 3 Report. We kept the long-term trend of the *Federal Outlook Scenario* in the Base Fuel forecast for S1, but made significant adjustments between 2009 through 2014 to account for NYMEX futures prices as of January 28, 2009.

The new High and Low Fuel forecasts are applied to S2 and S3, respectively. They utilize the corresponding 2008 IEO High Oil and Low Oil cases for the longer-term oil price trends. The near-term price trends for the High and Low Fuel forecasts were based on the NYMEX futures prices and probability levels consistent with the IEO High Oil and Low Oil cases.

For the super-high oil price scenario, S7, we have retained the *Peak Oil Scenario* from the Task 3 Report, but again incorporated reasonable near-term adjustments consistent with NYMEX futures prices through 2014 to account for the deep drop in market expectations relative to last summer. Consistent with the Peak Oil view, this scenario reflects a relatively quick return to high global demand for transportation fuels, declining proved global oil reserves, and peak OPEC production in 2010.

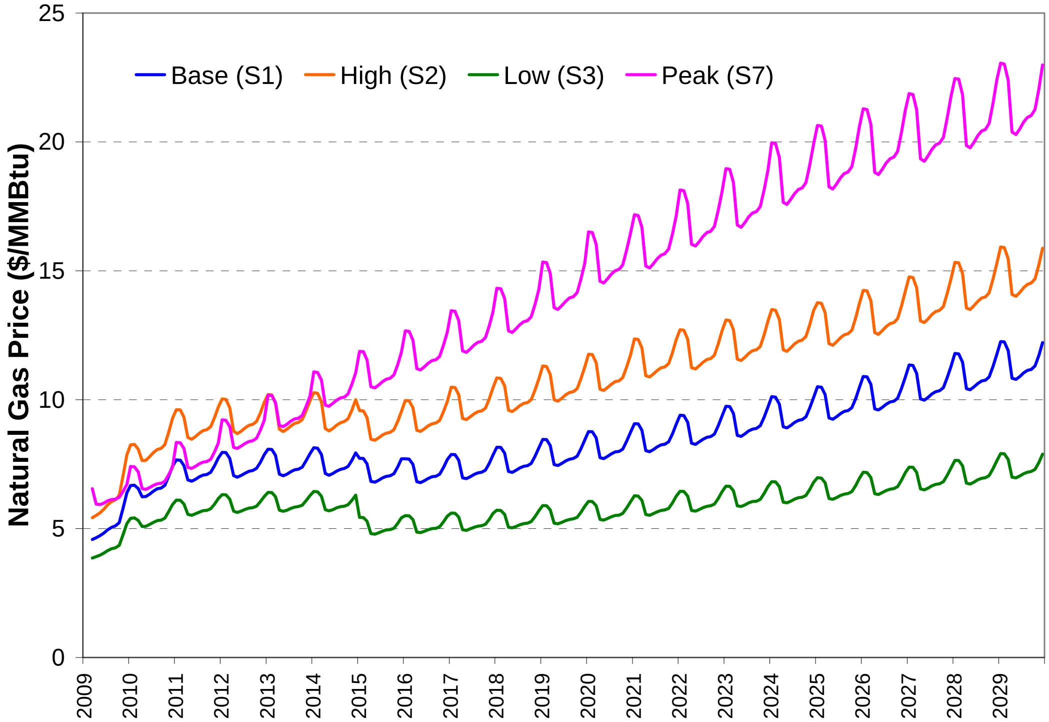
These scenarios result in a spread in crude oil prices by 2029 that ranges from $67/Bbl for the Low Fuel forecast to $109/Bbl for the Base Fuel forecast to $179/Bbl for the High Fuel forecast, to $239/Bbl for the Peak Oil forecast. The comparative annual average outlooks under four oil price forecasts are presented in Figure 5.

Figure 5. WTI Forecasts for S1, S2 S3, and S7



The WTI crude oil price forecasts provide the basis for our natural gas price forecasts through a scenario-specific oil-to-gas price ratio (OGPR). In our Base Fuel forecast we use an average OGPR of 9.5, which is consistent with the historical OGPR over the last 20 years. The OGPR has recently ranged from 8.0 to about 10.0. Given the recent volatility in OGPRs, we have assumed different OGPRs in the High Fuel and Low Fuel forecasts. In the High Fuel forecast the OGPR averages 12.0, primarily due to recent positive domestic gas supply developments involving unconventional gas production from the newly developed shale plays. The improved outlook for unconventional gas production results in domestic gas prices moving less in tandem with the high price trend in international oil prices and more in tune with domestic supply conditions. In the Low Fuel forecast, we have assumed an average OGPR of 9.0, which is in general accord with periods of low oil prices over the last 20 years. In the Peak Oil forecast, we assume an average OGPR of 11.8. For the monthly average prices for the Moderate Cap scenarios shown in Figure 6, the new forecasts result in a large and increased cone of uncertainty over the forecast period. By 2029 Henry Hub gas prices range from $7.40/MMBtu (Low), to $11.46/MMBtu (Base), to $14.89/MMBtu (High), and to $21.60/MMBtu (Peak Oil). As discussed in Section 1.3, the likelihood of gas prices materializing along the Peak Oil trajectory should be considered extremely low.

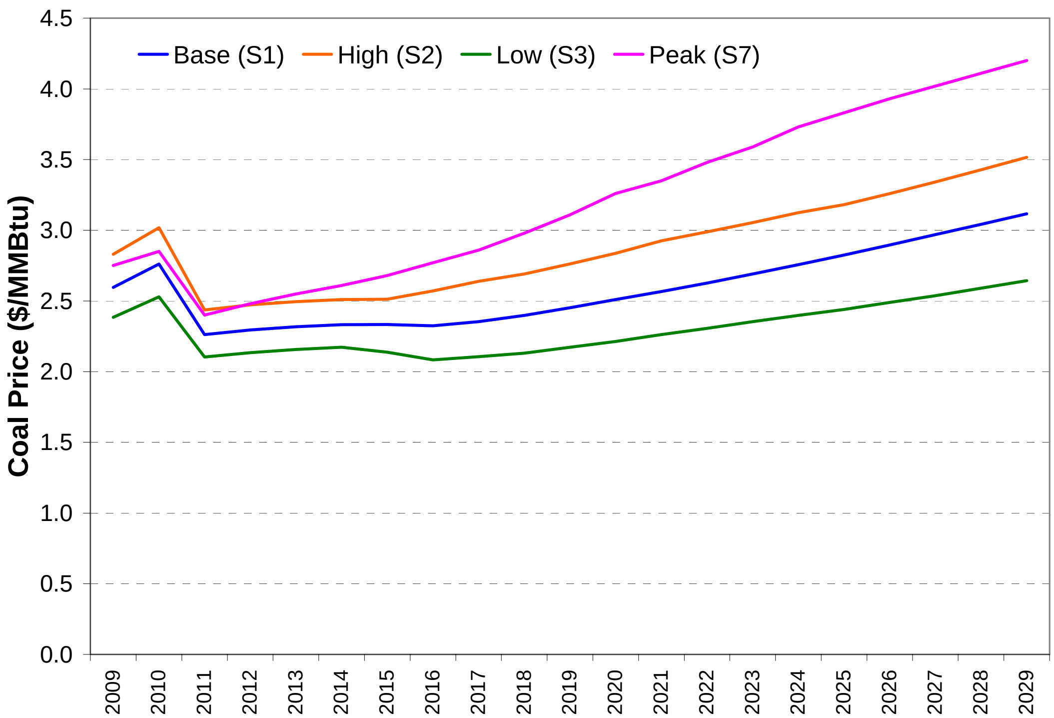
Figure 6. Henry Hub Forecasts for S1, S2 S3, and S7



The burner tip natural gas price forecasts include a transportation basis to relevant pricing points in PJM and surrounding market areas. The basis adders were first derived in 2007 for the Interim Report. We have adjusted the adders to key pricing points to account for anticipated changes in pipeline and storage infrastructure. The forecast of prices at Dominion Transmission's South Point, Transco's Zone 6 Non-New York and Texas Eastern Transmission's Zone M3 are in close accord with the forecast of basis adders used in prior studies. Consistent with prior research, monthly adders have been used in MarketSym over the forecast period.

We have updated the coal price forecasts by basin for the Central and Northern Appalachian Basins, the Powder River Basin and the Illinois Basin. The models for each basin provide long-term price trends based on trends in basin mining productivity, basin production, the level of coal exports, and natural gas prices. The natural gas price provides the linkage between the oil and coal price forecasts under each scenario. The relationship to natural gas prices is less important than trends in mining productivity. The near-term coal basin prices are based on the NYMEX futures prices for the Central Appalachian and Powder River Basins. We developed the High and Low Fuel coal forecasts for S2 and S3, respectively, through the application of historical price volatilities. The near-term forecasts of Northern Appalachian and Illinois Basin coal prices are based on the historical relationships between basin specific spot coal prices and the Central Appalachian basin. Again, the relationships are used to convert the NYMEX Central Appalachian futures prices to equivalent near-term price forecasts for the other two basins. Coal prices are then adjusted for transportation costs. In Figure 7 we show the forecast of annual average coal prices delivered to PJM for S1, S2, S3, and S7. In order to capture the effect of transmission interchange between PJM and neighboring control areas, similar forecasts have been prepared for NYISO, and portions of Midwest ISO, the SERC Reliability Corporation,[45] and ISO-NE.

Figure 7. Delivered Price of Coal in PJM for S1, S2, S3, and S7



4.3.2 Fuel Forecasts for S4, S5, and S6 (Strict Cap Scenarios)

Under the Strict Cap scenarios, S4, S5, and S6, we expect CO_2 allowance prices to be significantly higher, thereby affecting the price of all fossil fuels of relevance in MarketSym, as well as increasing the simulated LMPs. Price elasticities for power plant fuels relative to CO_2 allowance prices have been used to adjust the fuel price projections for S4 to S6, relative to the corresponding Base, High, or Low Fuel forecasts under the Moderate Cap scenarios, S1 to S3. Relative to the Moderate Cap scenarios, we assumed that the higher CO_2 allowance price forecast under the Strict Cap scenarios will have the following directional impact on commodity fuel prices based on our review of various studies:

- Natural gas prices will be *reduced slightly* despite the increased demand for this relatively low carbon-intensity fuel and the higher cost of replacing existing natural gas supply in western Canada and the U.S., *i.e.*, the accelerated depletion effect. Even though increased demand and higher replacement costs normally result in higher prices, the reason that we have incorporated the slight decline in natural gas prices when moving from a Moderate to a Strict Cap policy is due to the overall decline in demand for all fossil fuels if federal GHG reduction targets are aggressive.

[45] Formerly the Southeast Electric Reliability Council.

- Petroleum prices for distillate and residual oil will be *little changed*, since these prices are highly correlated with the commodity price of oil to the refiner, which was assumed to be unchanged in S4, S5 and S6 relative to the corresponding oil prices in S1, S2 and S3.

- Coal prices will be *reduced slightly* due to decreased demand for this relatively high carbon fuel and its slightly upward sloping supply cost function in Appalachian production basins, and, elsewhere in North America.[46]

Cross price elasticity coefficients have been estimated from simulation results in EIA's detailed 2006 study of four alternative GHG control policies that mainly vary in the stringency of their annual caps.[47] By calculating the difference in the EIA model results for GHG allowance prices between cases and the difference in natural gas and coal prices, a cross price elasticity coefficient was calculated for natural gas and coal.[48] The S4, S5 and S6 fuel prices have been calculated from the corresponding S1, S2, and S3 fuel price forecasts, the difference between S4, S5 and S6 GHG prices and S1, S2, and S3 GHG prices, and the assumed cross price elasticities. The resulting lower fuel prices for natural gas and coal are shown in comparison with the Moderate Cap fuel prices in Figure 8 for natural gas at Henry Hub and Figure 9 for PJM delivered coal. Note that Figure 8 and Figure 9 show annual average prices for each fuel.

[46] While coal commodity prices decrease in the stricter GHG scenarios, the burner-tip fuel plus GHG allowance cost of fuel from coal increases relative to natural gas due to coal being about twice as carbon-intensive as natural gas per MMBtu.

[47] EIA, *Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals*, March 2006, SR/OIAF/200601.

[48] The cross price elasticity coefficient is a linear slope coefficient, calculated as the ratio of the price differences.

Figure 8. Henry Hub Natural Gas Prices, S1 to S6

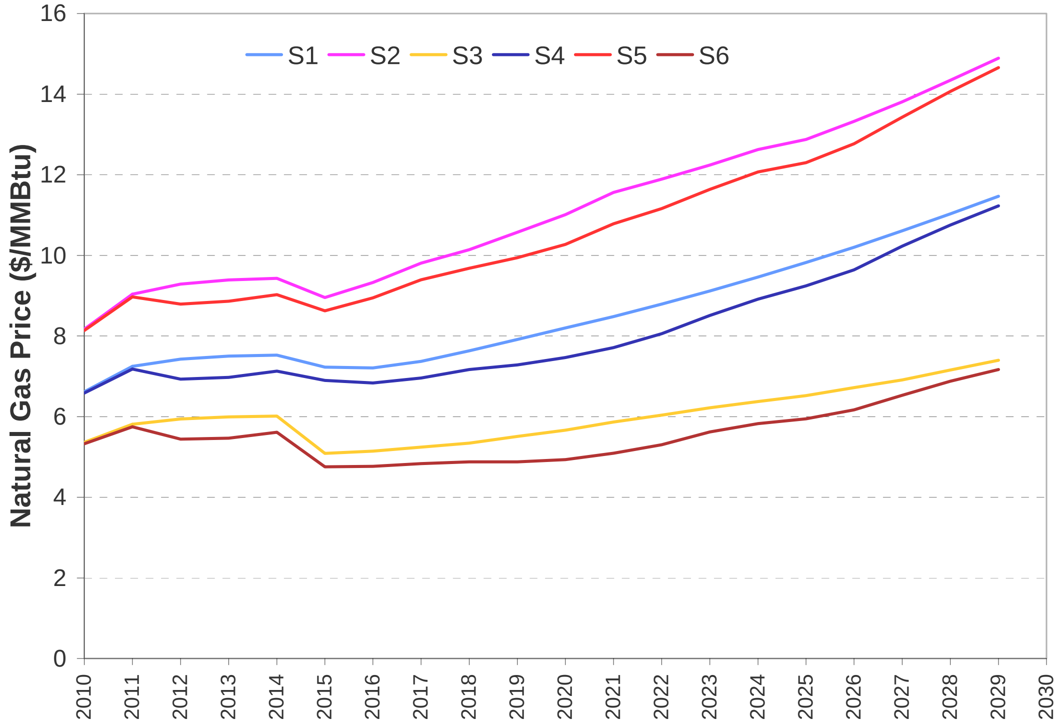
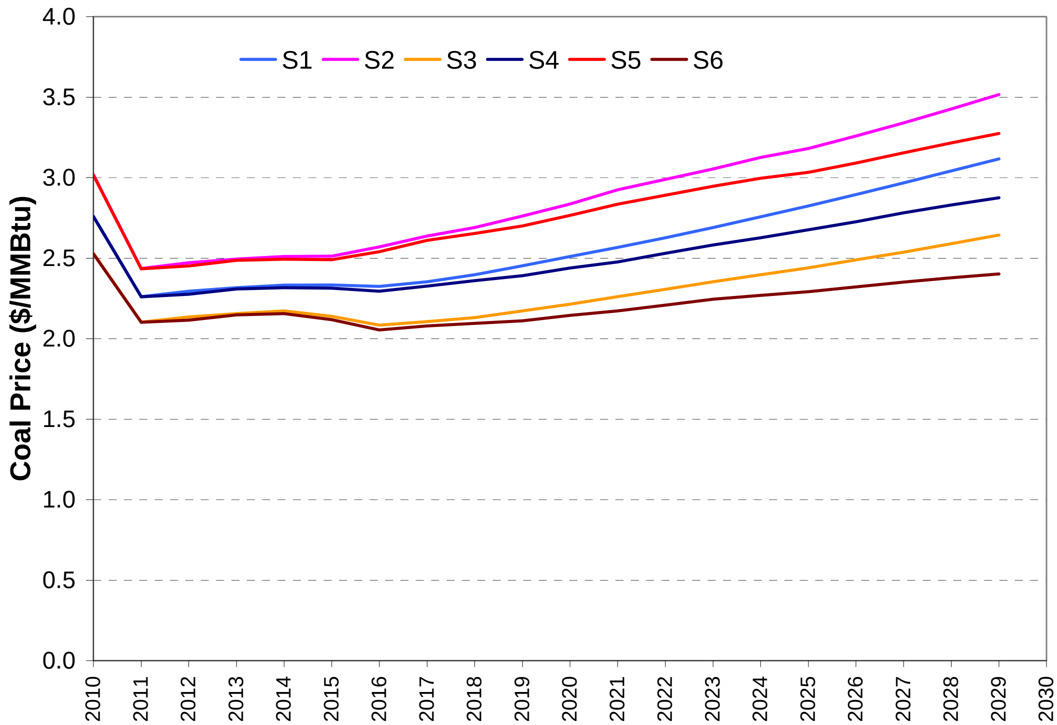


Figure 9. PJM Delivered Coal Prices, S1 to S6



4.4 Load Forecast and GDP Growth Rate

In the Task 3 Report, LAI used the PJM *2008 Report* to provide a single load forecast in MarketSym. In this study, we used the PJM *2009 Report* as the basis for different load forecasts by scenario. The current PJM load forecast includes the return of the Dusquesne load in PJM. The *2009 Report* was issued in January 2009, so it reflects recent forecasts of GMP for each load area. Slow growth in GMP over the next several years due to the recession has been addressed by PJM. The *2009 Report* also projects different relative rates of growth among areas.

Six distinct forecasts have been prepared, for S1 to S6. The PJM *2009 Report* has been used "as-is" for the Base GMP growth scenario, S1. Since the same GDP growth rate is assumed for S2 and S7, the same load forecast has been used for both scenarios.

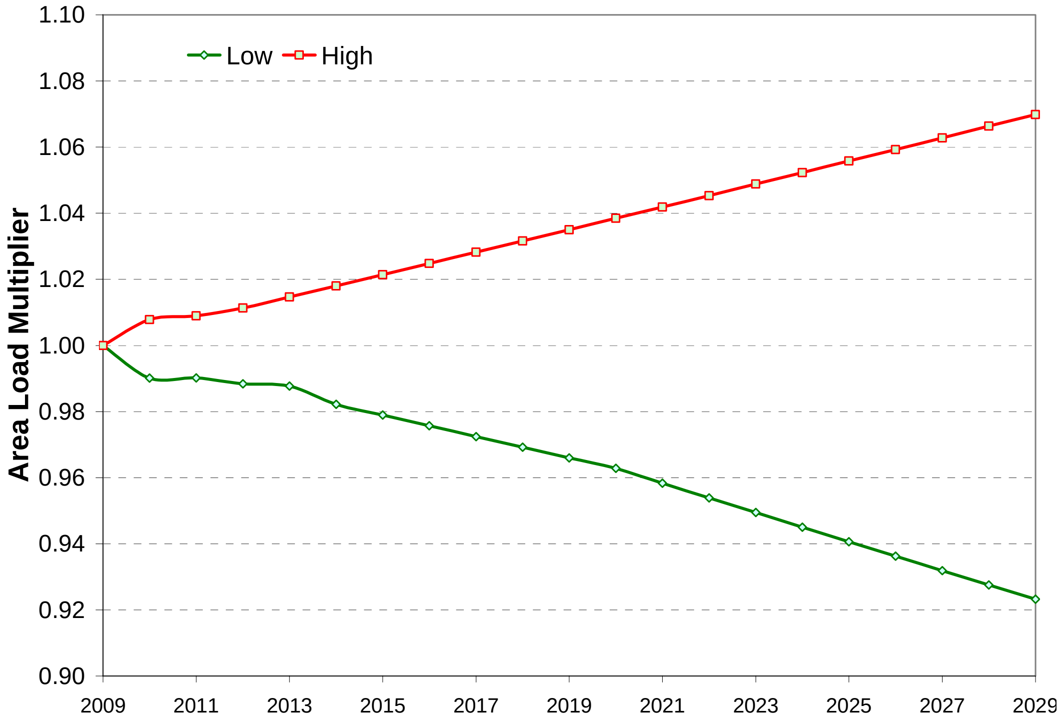
For the High (S2, S5) and Low (S3, S6) load growth scenarios, LAI assumes that GMP grows at slower or faster rates, and that electric load is correspondingly higher or lower due to its correlation with GMP. The Base load growth projection in S1 assumes the recession lasts four years. The High load growth S2 assumes the current recession lasts three years. The Low load growth S3 assumes the recession lasts five years, which is the maximum duration currently forecasted by macroeconomists. The Peak Oil forecast scenario, S7, uses the same GMP assumption as S2. We assume that after the current recession is over, GMP in the high load growth scenarios (S2, S5) grows 0.5% to 0.7% faster than in the Base scenario (S1), and GMP in the Low load growth scenarios (S3, S6) grows 0.5% to 0.7% more slowly than in the Base scenario. In the Low load growth scenarios (S3, S6), load does not fully recover to the Base scenario load, and in the High load growth scenarios (S2, S5), load rebounds above the Base scenario load.

For the High and Low load growth scenarios, a statistical analysis was performed to estimate the elasticity of percentage change in load to percentage change in real GMP. Using national data on annual electric energy consumption and real GDP for 1961 to 2007 and a linear regression model, a load/GDP elasticity of 0.68 was estimated, indicating that load changes less than proportionally to changes in GDP.[49] The percent difference between the High (or Low) real GDP projection used in S2 or S3 and the GDP projection of the Base scenario, S1, times the load/GDP elasticity, produces the load increase (or decrease) for S2 or S3 relative to S1.

The High (S2) and Low (S3) load growth scenarios were implemented as load index multipliers, relative to the Base load growth scenario, as shown in Figure 10. The same index multiplier projection was applied to each PJM load area. No adjustment from the Base load growth scenario was made to loads in areas outside PJM.

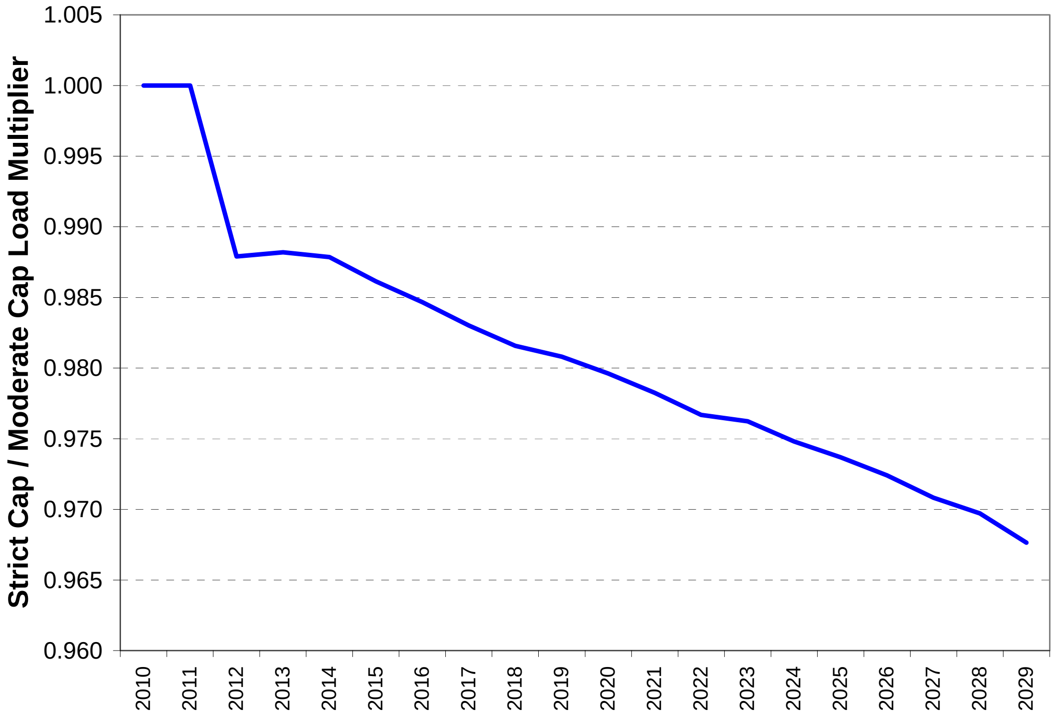
[49] The regression analysis also accounted for two other variables: change in electricity intensity relative to real GDP, and change in real retail electricity prices over time.

Figure 10. High and Low Load Growth Scenario Multipliers



For the Strict Cap scenarios, S4 to S6, greater investment in controlling GHG is expected to result in slightly lower real GDP growth. Furthermore, the significant increase in retail electricity prices will result in reduced energy use. As a result of these economic responses, LAI adjusted load projections in S4 to S6 to reflect slightly lower GDP and higher electricity prices in the Strict Cap scenarios. The same EIA GHG policy model simulation cases used for estimating fuel price elasticities were used here to estimate the load reduction impacts associated with the lower GDP and higher retail electricity prices resulting from a stricter GHG control program. The EIA load to CO_2 allowance price elasticity, calculated from the EIA study's "less" and "more" strict cases, times the increase in CO_2 allowance prices in our Moderate Cap and Strict Cap scenarios results in the same series of annual load multipliers for all three Strict Cap scenarios, shown in Figure 11.

Figure 11. Strict Cap to Moderate Cap Scenario Load Multipliers



4.5 Resource Mix

Consistent with the methodology in the Task 3 Report, new generation and DSM resources have been added to the resource mix in the chronological dispatch model to maintain reserve margins and meet reliability requirements. As discussed in Section 1.6, system reliability is preserved by adding new generic resources across PJM in all scenarios to maintain an IRM equal to 16.2% over the 20-year study period. No sensitivity analysis of the IRM criterion is conducted in any scenario. The schedule of additions also reflects the CETL values for SWMAAC, EMAAC, and MAAC. As discussed in Section 1.7, the CETL values for SWMAAC and MAAC have changed materially. Because distinct load forecasts have been used in each of the scenarios, and because they are based on different economic conditions and policy directions, the schedule of additions varies by scenario.

In all scenarios, new generation projects that are currently under construction, have executed long-term contracts, and/or have cleared in an applicable capacity market auction have been added to the resource mix.[50] In addition to the projects noted in the Task 3 Report, we have also incorporated the increased capacity at Constellation's Perryman and Riverside stations. In all scenarios, generic simple-cycle and combined-cycle units have been added as needed to maintain a mix of 2/3 simple-cycle to 1/3 combined-cycle units across the study horizon. Prior analysis conducted in the Task 3 Report indicated that this ratio represents close to the optimum blend of simple-cycle versus combined-cycle units.

[50] Details of the specific project additions and retirements have been described in Sections 2.1.4 and 2.1.5 of the Task 3 Report.

Consistent with the Task 3 Report, we assume that most of the renewable generation that will be built in PJM over the study horizon will consist of onshore wind turbines. The resource additions for the Moderate Cap scenarios S1, S2, and S3 are identical to the wind build-out schedule that was assumed in the *Reference Case*.[51] From a UCAP perspective, these scenarios include about 2,900 MW of onshore wind capacity across PJM in 2028, or 12,000 MW of installed wind capacity. This build-out schedule partially satisfies the states' Renewable Portfolio Standard (RPS) requirements since we assume that some of the RPS requirements will be met through alternative compliance payments (ACPs). We note that the proposed Bluewater offshore wind farm was not included in the *Reference Case* of the Task 3 Report and has not been included in the resource mix tested in any scenario in this study.

In the three Strict Cap scenarios, S4, S5, and S6, we postulated a marked increase in the development of renewable and nuclear resources at the expense of conventional fossil fuel generation. These three scenarios all assume that a third nuclear unit at Calvert Cliffs with a nominal capacity of 1,600 MW will be commercialized on January 1, 2018. To maintain the same level of resource adequacy, this will coincide with the retirement of a UCAP-equivalent amount of coal generation outside of SWMAAC. For S4 through S6, we also increased wind capacity by 20% relative to the Moderate Cap scenarios, at the expense of simple-cycle and combined-cycle units, based on the assumption that stricter GHG controls will be accompanied by policy initiatives promoting more wind power.

For the Peak Oil scenario, S7, we have assumed that more wind development will occur with very high oil and gas prices. We have therefore increased wind capacity by a further 20% relative to Scenarios S1, S2 and S3. This 20% increase in wind capacity has been applied as a 1.2 multiplier for wind capacity in each PJM zone in each year. Wind speed profiles and therefore wind capacity factors for all the MarketSym zones in all scenarios are unchanged from those used in the Task 3 Report.[52]

No hydroelectric, biomass, or landfill gas plants have been added in any scenario to satisfy RPS. Consistent with the Task 3 Report, we have postulated that the IOUs will meet Maryland's in-state solar requirement through actual photovoltaic installations, not the payment of the solar ACP. This study also assumes that only commercial / industrial crystalline silicon photovoltaic installations of at least 1 MW in size will be installed as needed to meet the solar band RPS requirement over the study period. By 2022, roughly 1,400 MW of solar capacity will have to be installed to meet the in-state solar RPS requirement.

The amount of DSM incorporated in the load forecast is based on PJM's outlook. In Maryland, the amount of DSM included in S1, S2, and S3 is the same as the *Reference Case* in the Task 3 Report, *i.e*., 25% of the EmPOWER Maryland goal through 2015. For S4 through S6, we have assumed that more stringent GHG legislation will be accompanied by policy initiatives promoting enhanced DSM. Therefore in S4, S5, and S6 we have increased the total DSM saturation rate by 20% over the Moderate Cap scenario level. In S7 we assumed higher price levels would also result in increased DSM.

[51] See Task 3 Report, Section 6.2.

[52] See Task 3 Report, section 6.2, Table 20.

4.6 Capacity Market

The mechanics of the RPM are described in Section 2.2 of the Task 3 Report.[53] Important changes to the RPM planning parameters and related assumptions used to update our capacity price forecast are addressed in Section 1.7 of this report. The results of the updated analysis are presented below and with the basis for our revisions.

For each scenario, S1 through S7, LAI developed three forecasts of UCAP clearing prices. The base forecast for each scenario is based on the Net CONE values distributed in PJM's Planning Parameters for the 2012/13 auction. As discussed in Section 1.7, FERC has not yet approved PJM's proposed CONE values and other tariff revisions. Therefore, LAI also prepared two alternative forecasts for each scenario, one with CONE increased by 25% and one with CONE decreased by 25%.[54]

4.6.1 Base Capacity Price Forecast for S1

In the Task 3 Report, LAI based our UCAP forecast on the proposed Net CONE value of $222.80/MW-day for both SWMAAC and the RTO, which was an interim value distributed by PJM to stakeholders in Q4 2008 as part of the RPM stakeholder process. PJM has posted 2012/13 Planning Parameters that establish Net CONE values of $286.76/MW-day for RTO, $252.06/MW-day for MAAC, and $213.02/MW-day for SWMAAC. In the 2012/13 Planning Parameters, Gross CONE for RTO and SWMAAC are identical, but Net CONE in SWMAAC is lower due to a higher EAS offset for that region.

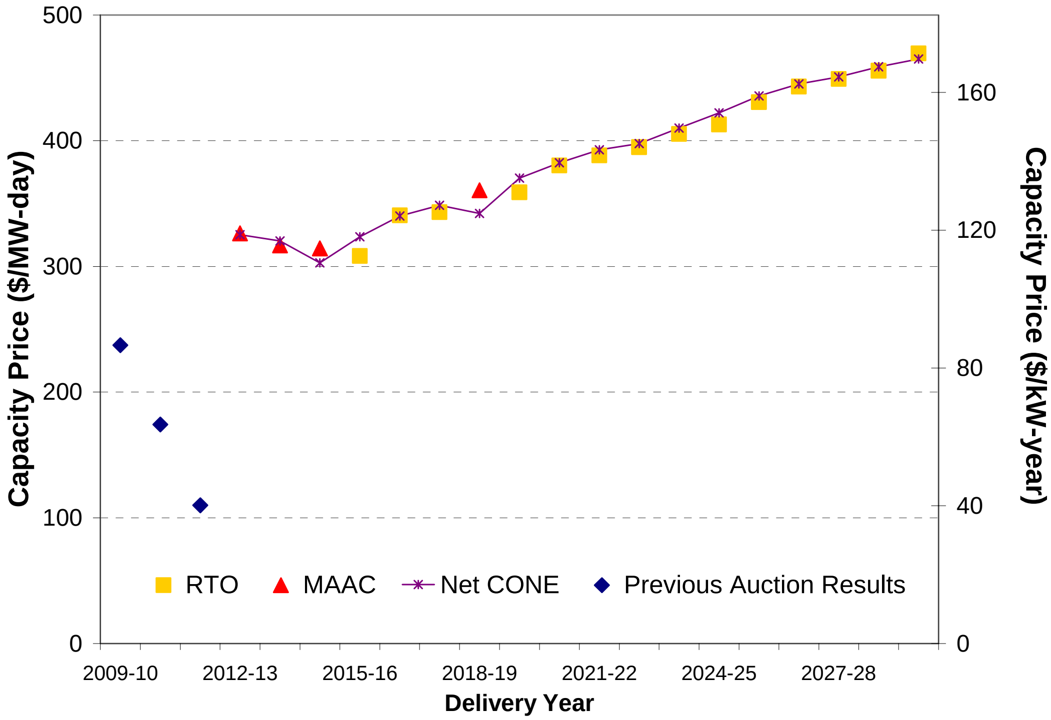
Other changes detailed in the 2012/13 Planning Parameters also affect the capacity price forecast. CETL for SWMAAC was increased from 6,897+ MW for the 2011/12 auction to 7,400 MW for the 2012/13 auction, an increase of 503 MW due to transmission upgrades and improvements around Baltimore and the District of Columbia. The CETL/CETO threshold that determines whether a region can bind was raised from 105% to 115%.

The S1 UCAP forecast is shown in Figure 12. Three years of historic clearing prices for SWMAAC are shown on the left side, set by the auctions held for Delivery Years 2009/10 through 2011/12. For the forecast period, the plot indicates which region sets the clearing price for SWMAAC. In S1, MAAC sets the clearing price for the first three Delivery Years, and then the RTO sets the clearing price for each subsequent Delivery Year thereafter (except 2018/19). Net CONE values are also shown for each Delivery Year for the region that sets the clearing price.

[53] The capacity price forecast for the resource options tested in the Task 3 Report can also be found in Section 2.2 of the Task 3 Report.

[54] The ±25% adjustment is made to Gross CONE which is escalated by the 2% inflation rate over time. The EAS offset is then deduced from Gross CONE consistent with MarketSym results for each scenario to establish Net CONE values.

Figure 12. S1 UCAP Price Forecast (Base CONE Value)



The clearing price for the first forecast Delivery Year, 2012/13, is significantly higher than the most recent historical clearing price primarily due to higher CONE values and the change in the CETO/CETL threshold to 115%. This is a key difference from the Task 3 Report forecast, in which SWMAAC clearing prices were never set by MAAC. PJM expects that MAAC will have a CETL/CETO ratio of 114% in 2012/13 according to the latest Planning Parameters, just failing the 115% threshold, and PJM will therefore calculate a clearing price. Under the previous threshold of 105% a MAAC price would not have been calculated.[55]

Beginning in 2015/16, we anticipate that the RTO will have worked off enough excess capacity that the RTO clearing price rises to just below Net CONE. Since the RTO Net CONE is higher than the MAAC Net CONE, and both markets are near equilibrium, all generators in MAAC, including SWMAAC, will receive the higher RTO price. Beginning in the following year, we modeled RTO capacity in "equilibrium" close to the IRM for the duration of the forecast horizon, with clearing prices close to Net CONE. In S1, net EAS revenues for the reference RTO unit are about flat over the period of the forecast. As a result, Net CONE increases in nominal terms over the course of the forecast as Gross CONE escalates by the long-term inflation rate.

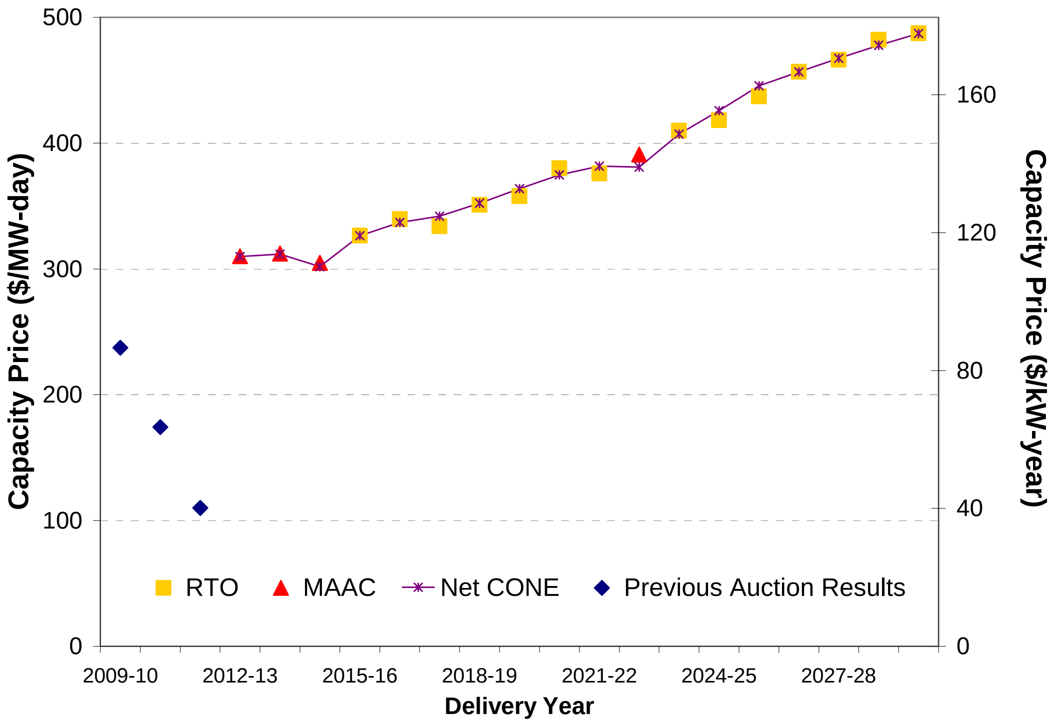
[55] For the 2012/13 auction, PJM is allowing for the possibility of up to seven different capacity clearing prices. Auctions will be run for the RTO, MAAC, EMAAC, SWMAAC, PS, PS North, and DPL South. For this auction, PJM determined that an auction will be run for a sub-region if the CETL/CETO ratio is less than 115% *or* if there has been a binding constraint in that region in any of the three immediately previous auctions.

4.6.2 Base Capacity Prices for S2 through S7

For S2 through S7, LAI developed separate forecasts to track changes to capacity clearing prices based on different load growth and supply additions, varying EAS offsets based on energy margins, and other factors.

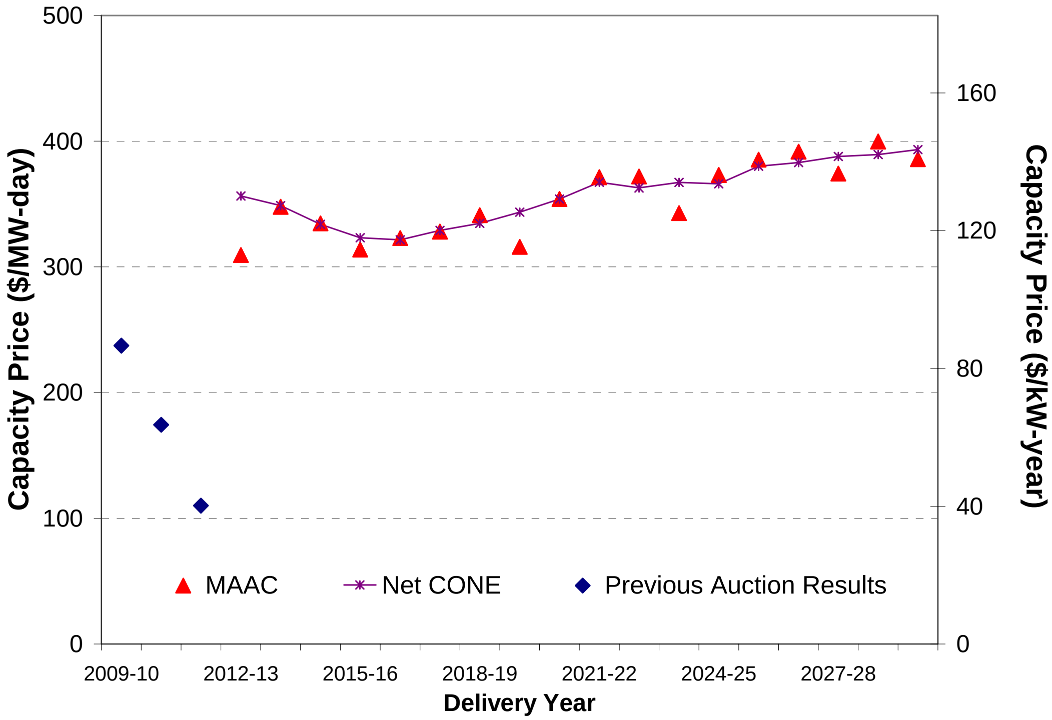
In S2, energy margins are forecasted to be slightly lower than those in S1 in the later years of the forecast, causing an increase in Net CONE. A key difference in the S2 forecast is that the higher load forecast causes the RTO to reach equilibrium a year earlier than in S1. As with S1, MAAC still sets the clearing price in the first three years of the forecast, but in 2015/16, when the RTO begins setting the clearing price, it has already reached equilibrium, causing the price to clear more or less at Net CONE, whereas in the S1 forecast the 2015/16 clearing price was below Net CONE. The S2 UCAP forecast is shown in Figure 13.

Figure 13. S2 UCAP Clearing Price Forecast (Base CONE Value)



In S3, lower fuel prices increase spark spreads, causing a higher EAS offset and lower Net CONE, particularly in the second half of the forecast. Low load growth and non-market wind and DSM capacity additions cause the RTO to maintain a capacity excess through the end of the study period; hence, the higher MAAC clearing prices (compared to RTO) set clearing prices for each year over the forecast period. In most years, SWMAAC has a CETL/CETO ratio less than 115%, but SWMAAC resources receive the higher MAAC clearing price in each of those years. In addition, the MAAC clearing price is below Net CONE in several years, particularly 2012/13, because load growth is low relative to capacity additions. Our forecast of capacity clearing prices under S3 is shown in Figure 14.

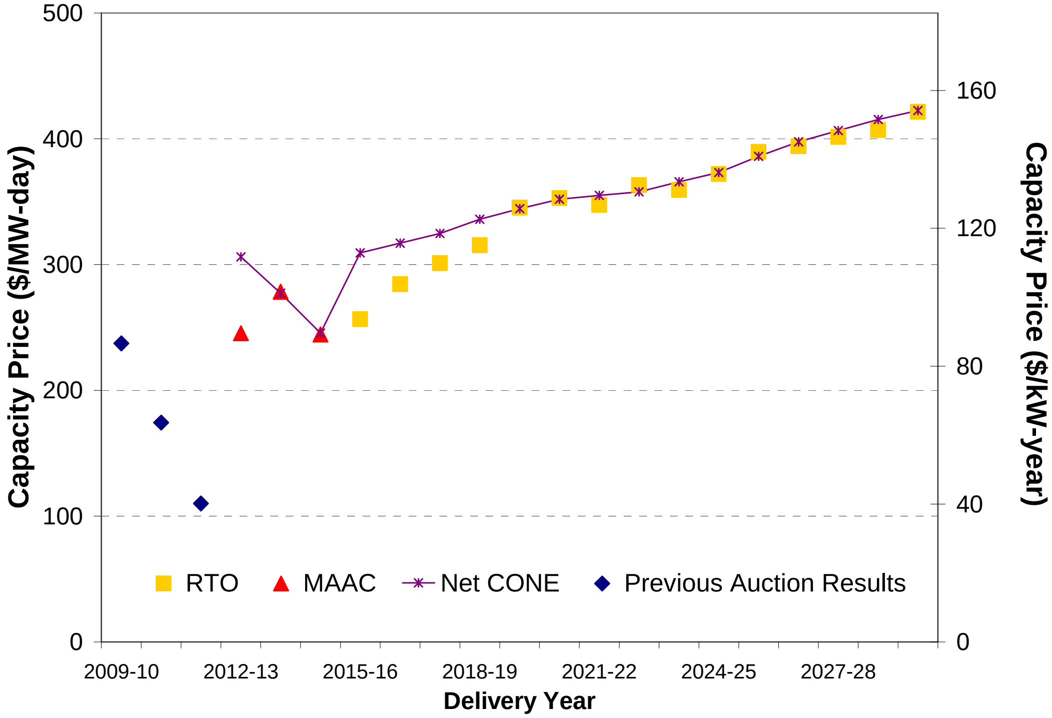
Figure 14. S3 UCAP Clearing Price Forecast (Base CONE Value)



In S4, MAAC sets the clearing price in the first three years of the forecast. In 2012/13, the clearing price is well below Net CONE due to reduced load growth. In 2013/14 and 2014/15, Net CONE declines significantly, due to a high EAS offset resulting for high revenues for generators in preceding years, which reduces the clearing price. By this time, MAAC is in equilibrium and UCAP clears near Net CONE.

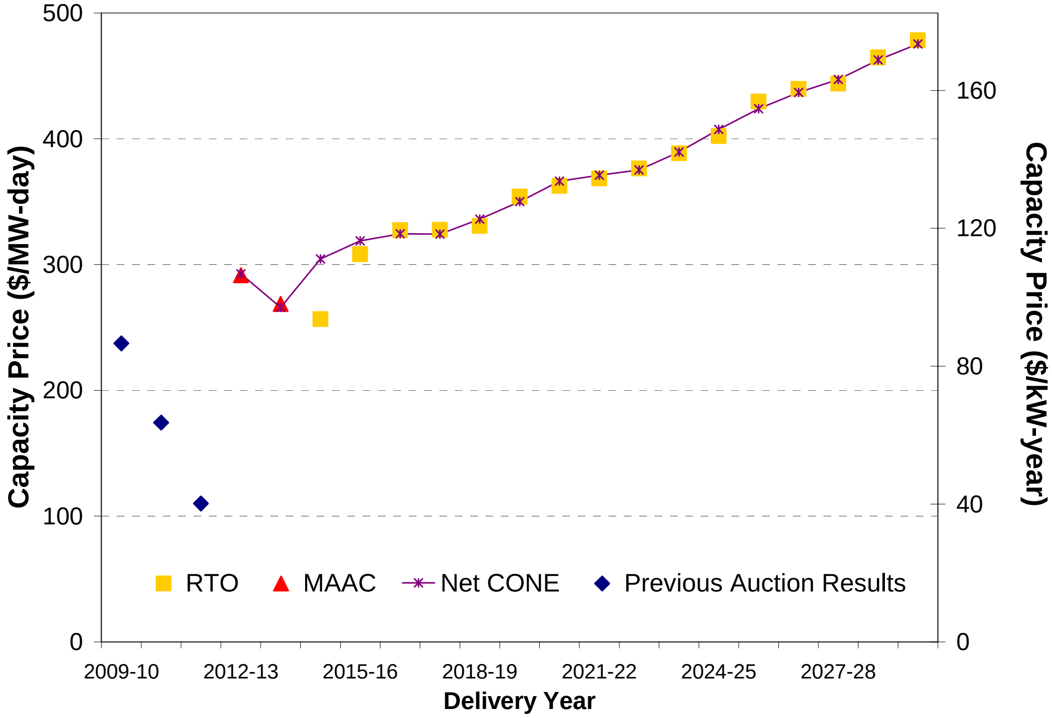
Beginning in 2015/16, the RTO sets the clearing price. Because of the low load forecast, RTO still has excess capacity at this point, and does not reach equilibrium until 2019/20, following which prices clear near Net CONE. The 2014/15 Net CONE reflects a high EAS offset for MAAC generators, while the 2015/16 value for Net CONE reflects much lower revenues for the reference unit in the RTO. The S4 forecast of capacity prices is shown in Figure 15.

Figure 15. S4 UCAP Clearing Price Forecast (Base CONE Value)



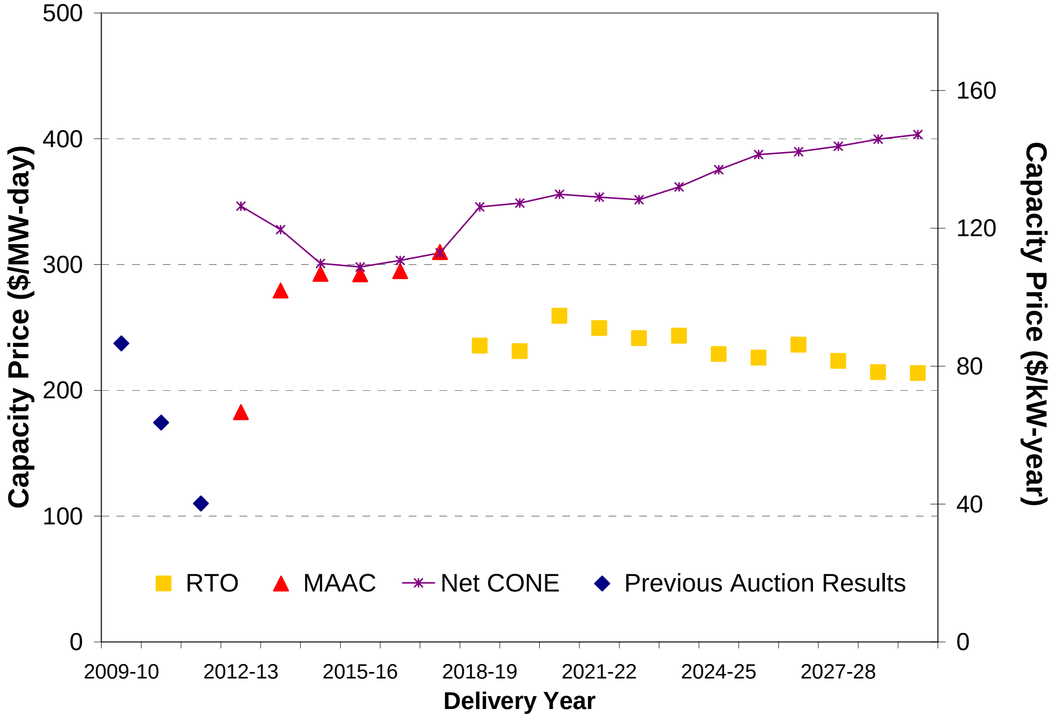
The S5 forecast is based on a higher load growth assumption than S1. Hence, MAAC sets the clearing price for only two years. By year three there is no more excess capacity in the RTO, causing UCAP prices to rise and causing the RTO to set the clearing price in 2014/15. One year later, RTO has nearly reached equilibrium, clearing just below Net CONE. Under the equilibrium assumptions used in this study, clearing prices are at or near Net CONE for the duration of the forecast. In S5, energy margins are similar to those in S1 and S2. Our S5 forecast is shown in Figure 16.

Figure 16. S5 UCAP Clearing Price Forecast (Base CONE Value)



S6 is similar to S3 for the first half of the forecast. Relatively high energy margins put downward pressure on Net CONE in MAAC, which sets the clearing price through 2017/18. Clearing prices are set by the RTO beginning in 2018/19, due primarily to the postulated addition of a third nuclear unit at Calvert Cliffs in 2018, the effect of which is to depress the MAAC price to such an extent that RTO sets the clearing price for the remainder of the forecast. Since the RTO has excess capacity for the entire forecast in S6, clearing prices are well below Net CONE beginning in 2018/19 through the end of the forecast. The S6 forecast is shown in Figure 17.

Figure 17. S6 UCAP Clearing Price Forecast (Base CONE Value)



In S7, we postulate oil and natural gas prices under Peak Oil coupled with high load growth. The resulting capacity clearing prices reflect a high Net CONE, due to reduced margins for peaking generators burning expensive fuel, as well as rapid reduction of the excess capacity in PJM. MAAC sets clearing prices near Net CONE for the first few years, while the RTO sets clearing prices beginning in 2015/16, at which point it is already at equilibrium, through 2028/29. MAAC sets the clearing price in 2029/30, also at Net CONE. The S7 forecast is shown in Figure 18. Figure 19 compares the UCAP clearing price forecast for all seven scenarios.

Figure 18. S7 UCAP Clearing Price Forecast (Base CONE Value)

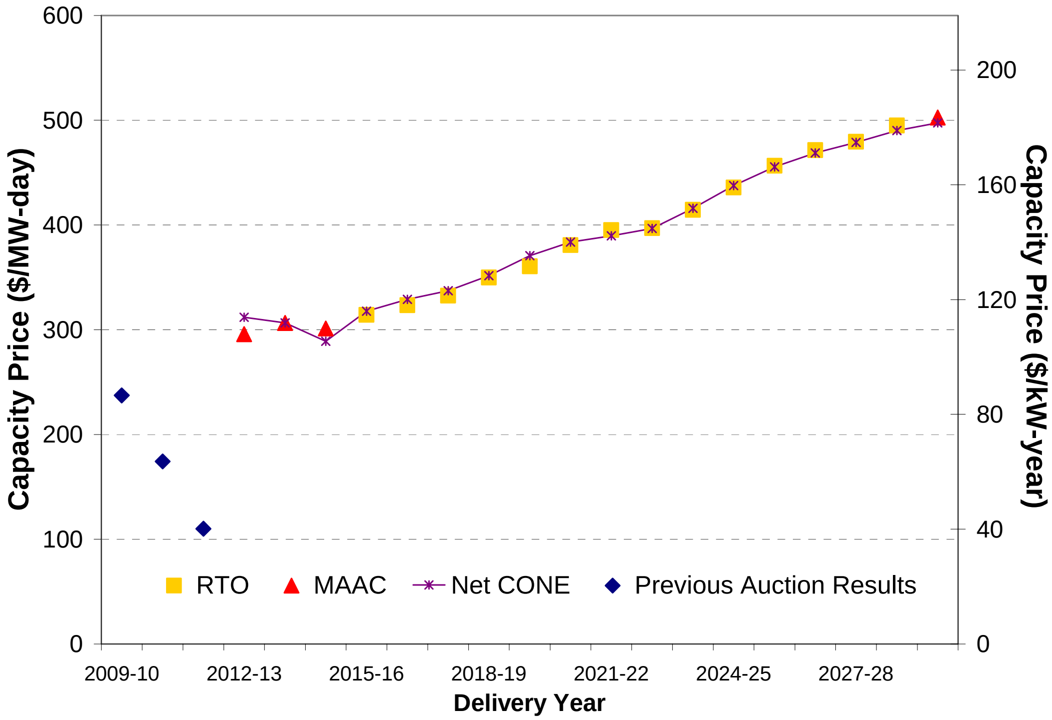
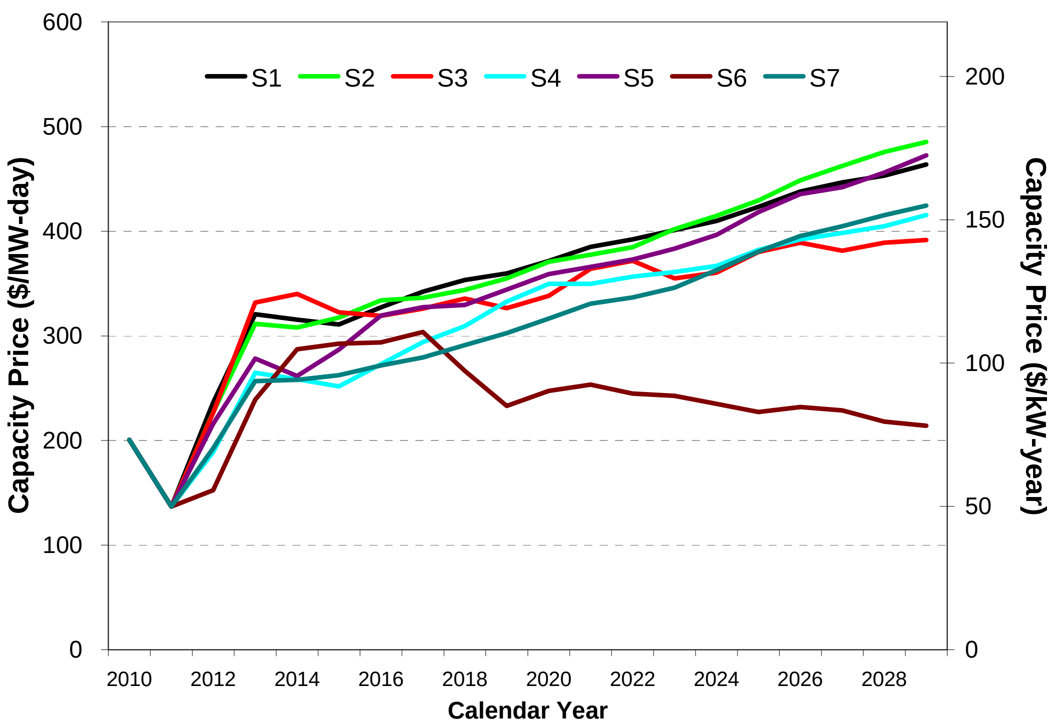


Figure 19. UCAP Clearing Price Forecast (All Scenarios, Base CONE Value)



4.6.3 Capacity Price Uncertainty

Capacity prices, like energy prices, can be volatile. For purposes of examining the economics of the return to rate base regulation, LAI did not evaluate the potential divergence between UCAP clearing prices and Net CONE in the RTO or other zones in PJM. There are many reasons why there could be a significant differential between Net CONE and UCAP clearing prices. As explained in Section 8.1.5, vertically integrated utilities are able to add new resources under rate base regulation prior to the need date. Moreover, the dynamics of the investment cycle may cause periods of capacity overhang due to the "lumpiness" of new capacity additions and investors' propensity to overbuild. For these reasons, the UCAP price forecasts represent the inherent value of capacity under the simplified equilibrium assumptions used to assess the economic merit of rate base regulation.[56]

In the competitive market for high quality generation assets, investors would be inclined to use more conservative assumptions about capacity prices over the long term, thereby capturing the impact of the investment cycle on valuation and risk. While the use of the full intrinsic value of capacity for purposes of valuing the Mirant assets under FMV certainly increases the value of the fleet, it does not have a significant impact on the risk-reward profile derived in the financial analysis. This is because the capacity revenues earned by the fleet in the EVA analysis are based on the same equilibrium assumption, so they largely offset each other. Similarly, a lower FMV acquisition cost would be offset by correspondingly lower capacity revenues.

LAI's energy and capacity price forecasts necessarily make a number of overriding policy assumptions about the functioning of the deregulated wholesale markets. We have specifically postulated that the capacity market will be in equilibrium over the long term in most scenarios, with just enough additions to meet PJM's IRM and deliverability requirements when the need warrants. Again, capacity markets in PJM may be long for extended intervals, thereby decreasing UCAP prices relative to Net CONE under equilibrium conditions. Despite low capacity prices and reduced demand, there is expected to be new capacity added by utilities and merchant developers with active construction programs, along with wind, renewables, and demand-side resources driven by state RPS requirements. These capacity additions could keep UCAP prices depressed relative to the UCAP price forecast that serves as the benchmark in the analysis for the intrinsic value of capacity in PJM.

- High capacity values could be the result of a higher Gross or Net CONE, more stringent reserve margin requirements, a tightening up of capacity resources, or some combination of factors. For example, the original engineering consultant reports that estimated GT capital costs had higher Gross CONE values. The joint PJM / Independent Market Monitor (IMM) proposal as of mid-October 2008 had a $273.95/MW-day Net CONE for SWMAAC, about 29% higher than PJM's 2012/13 Planning Parameter value of $213.02/MW-day, which was filed on January 30, 2009. The joint PJM / IMM Net

[56] Investors generally refer to the inherent value of capacity as the "intrinsic" value of capacity – there is also "extrinsic" value associated with the use of capacity to energize trading operations and as a risk management tool, but this component of total capacity value has not been included in the derivation of capacity prices or FMV.

CONE values for EMAAC and MAAC were also higher than PJM's 2012/13 Planning Parameters.

- Low capacity values could be the result of a lower Gross or Net CONE, long-term oversupply (due to lower load growth, vertically integrated utility construction programs, or higher wind / renewable development), relaxed reserve margin requirements, adopting an "empirical" Net CONE value (based on the previous year's clearing price), or some combination thereof. For example, the Net CONE value for the previous 2011/12 auction was $171.40/MW-day, about 20% less than PJM's current proposed value for SWMAAC.

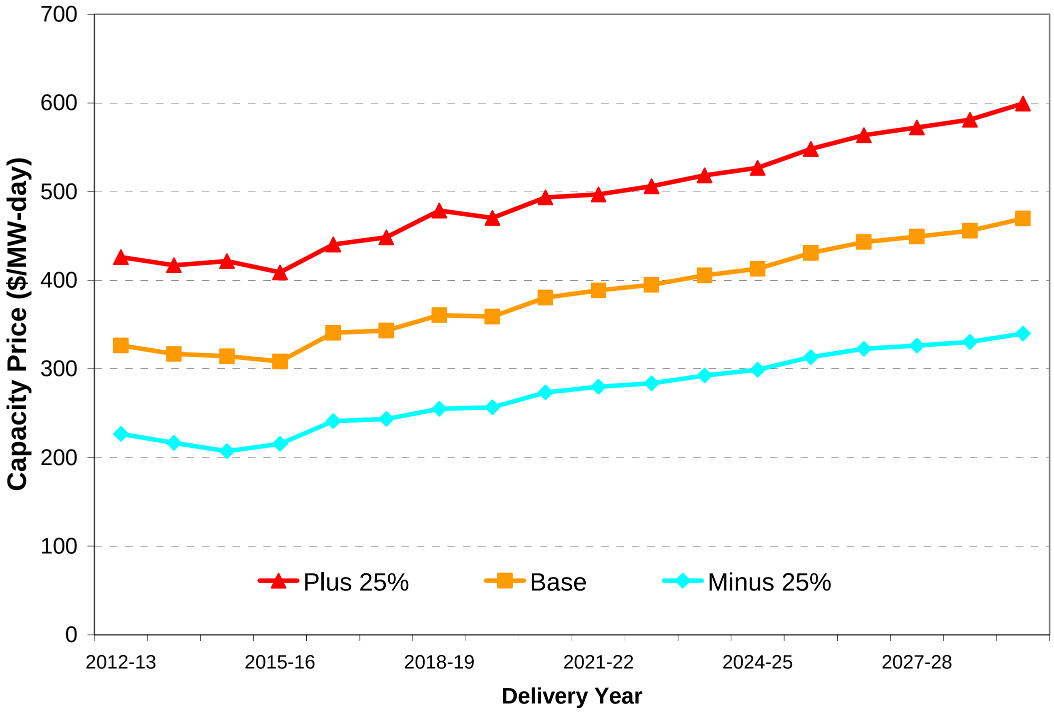
In considering uncertainty around future Gross CONE values and UCAP prices, there is no way to foresee if and how future regulatory and political forces will develop consensus Gross and Net CONE values. Therefore, we are comfortable with a 25% bandwidth around our base Gross CONE values, consistent with the examples mentioned above, with Gross CONE for SWMAAC ranging from $156,761 to $94,057/MW-year, reasonable upper and lower bounds, as shown in Table 11. The high and low Gross CONE values were selected to cover all of the RPM uncertainties that would lead to higher or lower UCAP prices. LAI believes that there is greater likelihood that UCAP prices could be lower, rather than higher, over time.

Table 11. Capacity Price Uncertainty – High and Low Gross CONE Values for 2012/13 ($/MW-yr)

	Probability	RTO	MAAC	SWMAAC
Base	50%	$125,409	$135,600	$125,409
High (+ 25%)	10%	$156,761	$169,500	$156,761
Low (- 25%)	40%	$94,057	$101,700	$94,057

The effect of increasing or decreasing Gross CONE for a given scenario is nearly linear in most cases. Figure 20 shows our S1 forecast of SWMAAC capacity clearing prices using the Base CONE value (as shown in Figure 12, above) as well as the higher and lower CONE inputs.

Figure 20. Comparison of S1 UCAP Forecast Under Gross CONE Sensitivities



5 FAIR MARKET VALUE

5.1 Methodology

FMV reflects the price a willing buyer would pay a willing seller with both parties acting prudently and without compulsion. In this study we have also assumed generally normal financial conditions, not the distressed financial markets that currently exist. A condemnation process through the state judicial system would determine an "award" to be paid by the buyer to the seller. The basis for determining the amount of the award must be clearly understood, including all sources of value. Under Maryland's condemnation processes, any award paid to Mirant must be "just," with consideration beyond current plant conditions, including planned and potential improvements as well as direct and consequential losses from the condemnation.

Traditional valuation principles were discussed in Section 8.3 of the Task 3 Report and need not be repeated in this study. The Net Income Capitalization method is most commonly used in finance and is the appropriate approach for valuing the Mirant assets. We use two variants of this approach: (i) applying a multiplier to our EBITDA forecast and (ii) a DCF forecast (after depreciation, income taxes, and debt payments) using the equity hurdle rate. Both the EBITDA multiplier and DCF discount rate reflect the capital structure and costs for typical generation asset buyers as well as the benefits, costs, and risks of the assets under specified market conditions.

5.2 EBITDA Estimate

Consistent with the Task 3 Report, we have developed a forecast of annual EBITDA for the relevant period based on our energy and capacity market models. We used the assumptions corresponding to the Base scenario, S1, as described in Section 4, along with the corresponding capacity price forecast under the Base Gross CONE case. These assumptions result in lower levels of EBITDA than in the Task 3 Report because commodity prices are dramatically lower than those used last year. Figure 21 shows annual EBITDA for the period 2010 through 2029, broken down into key revenue and expense components.[57]

It is useful to look at how EBITDA is provided by the different classes of generation assets included in the Mirant Maryland fleet. Figure 22 shows annual EBITDA by type of plant. The coal-fired steam units provide the overwhelming majority of the cash flow.

[57] Consistent with the Task 3 Report, we have included an allocation of the ongoing "Gross Additions to Utility Plant" expenditure estimate from Pepco's Form 1 data in the variable O&M category. If more detail had been available, an allocation to fixed O&M by generation type might have provided a more accurate breakdown of EBITDA by generation class, but would not have affected total annual EBITDA.

Figure 21. Mirant Fleet Annual EBITDA

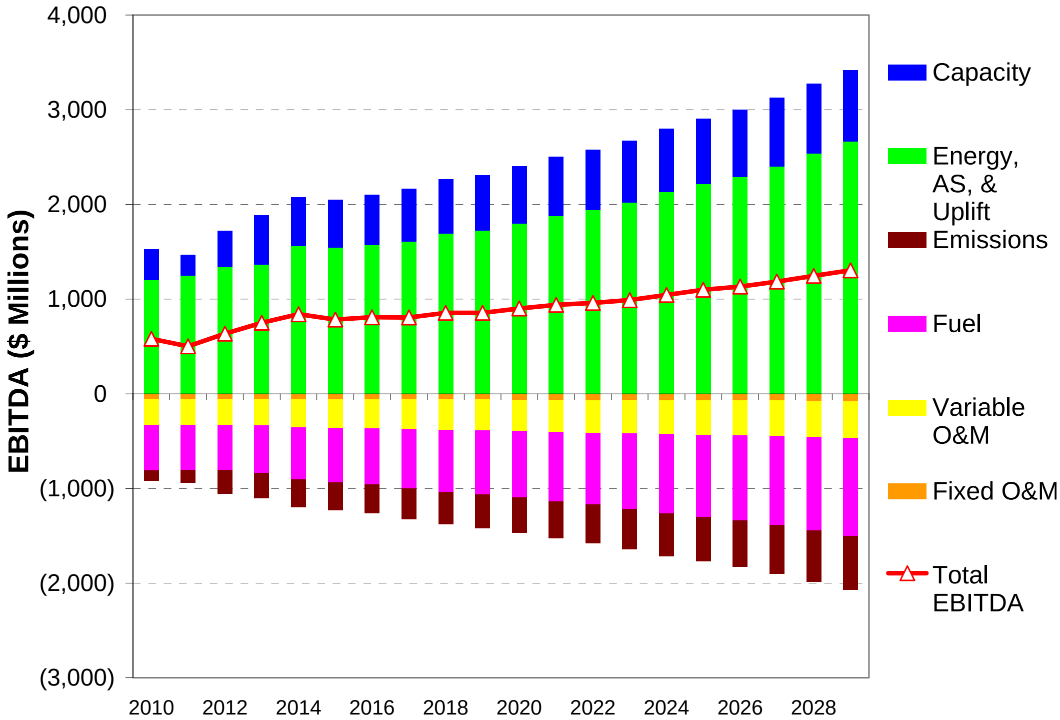
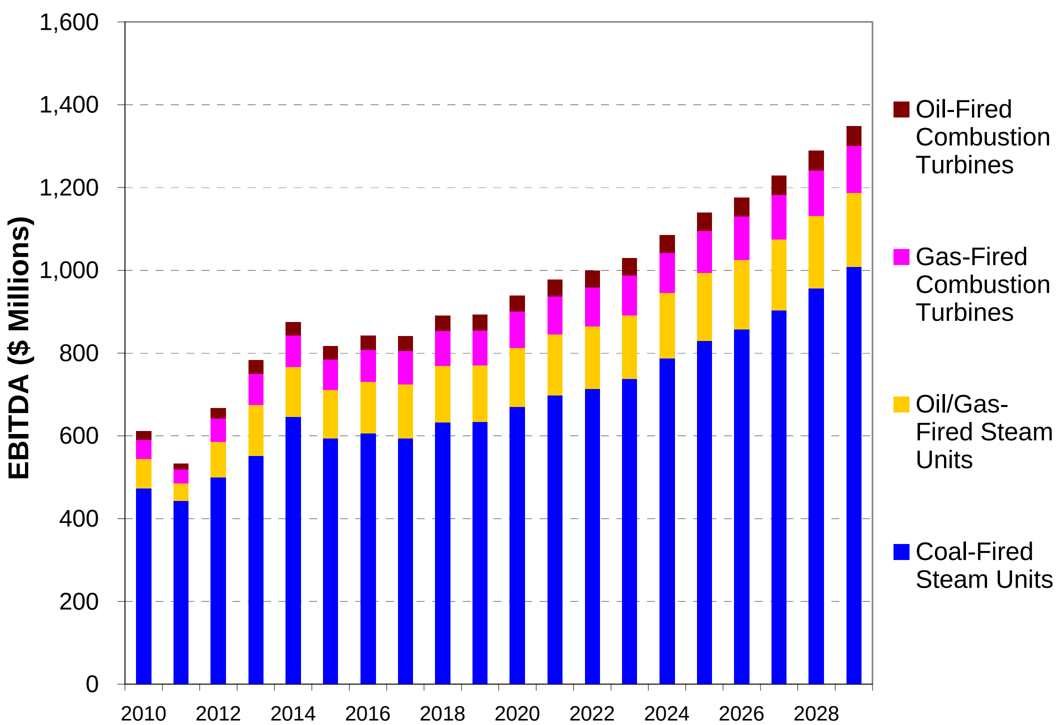


Figure 22. Annual EBITDA by Generation Type



In Figure 23 through Figure 26, we report annual EBITDA by category for each generation type. We note that the vertical scales differ from chart to chart. All capacity types earn capacity revenues under the RPM structure. In addition, coal-fired steam units provide substantial net energy margin (EAS less fuel expense, variable O&M expense, and emission expense), while other generation types provide little or no net energy margin.

Figure 23. Coal-Fired Steam EBITDA

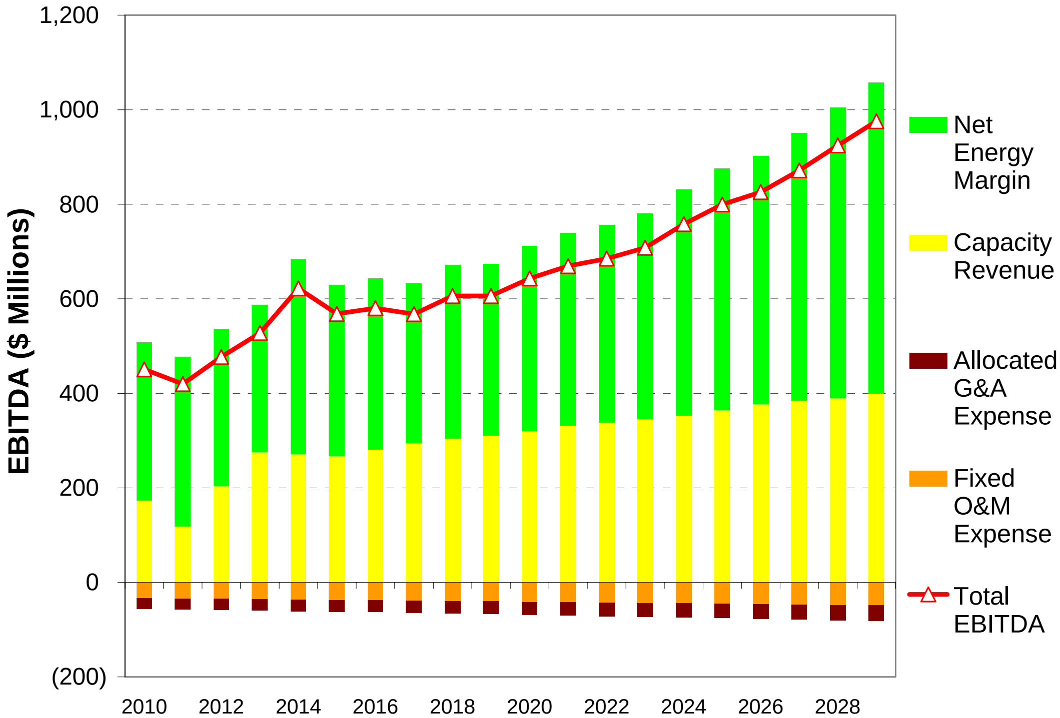


Figure 24. Oil/Gas-Fired Steam EBITDA

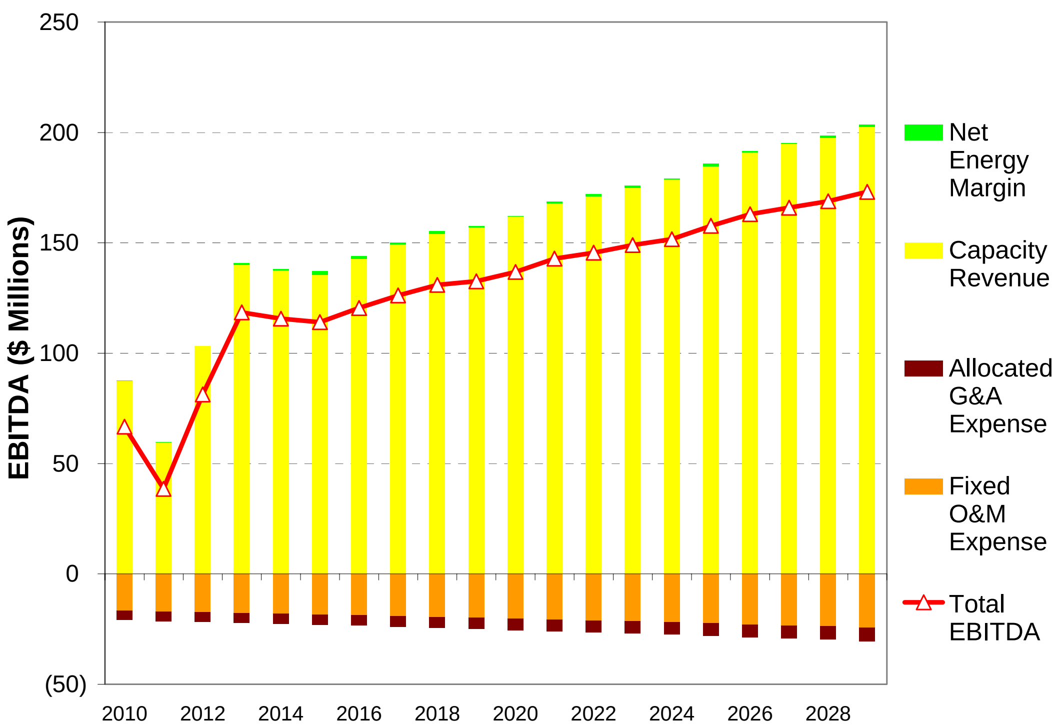


Figure 25. Gas-Fired Combustion Turbine EBITDA

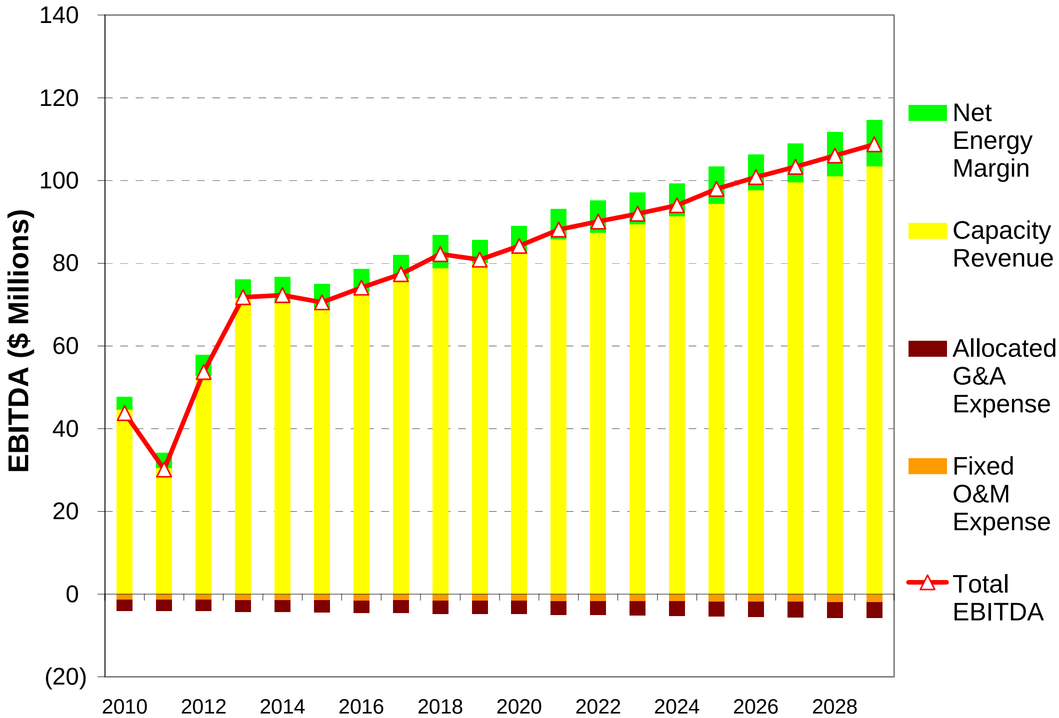
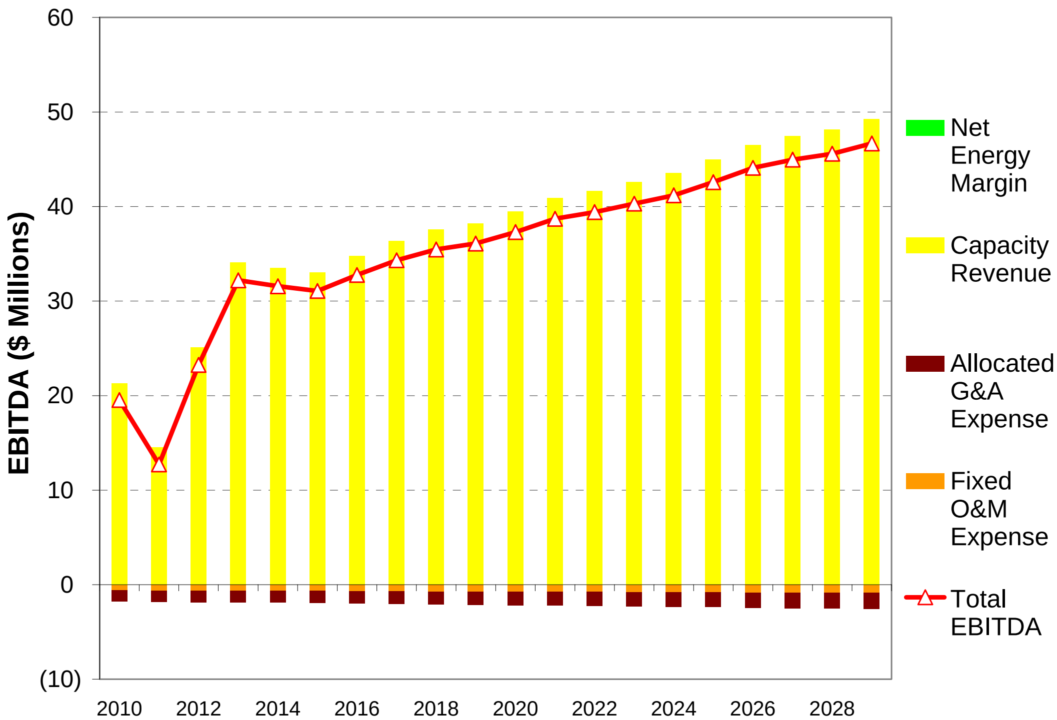
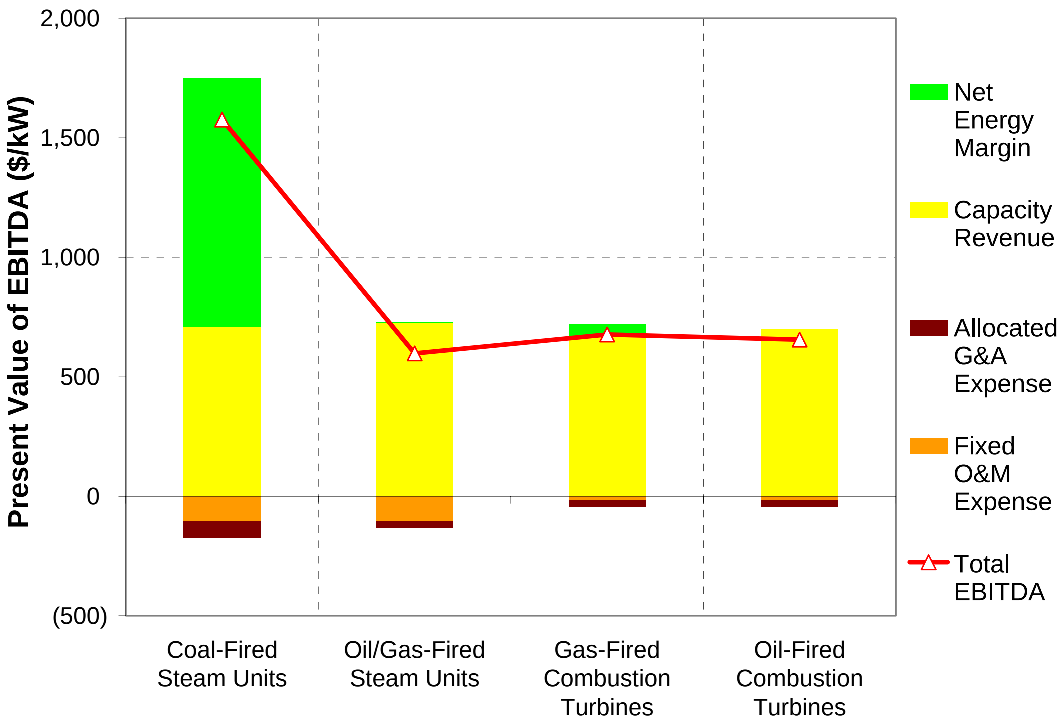


Figure 26. Oil-Fired Combustion Turbine EBITDA



In Figure 27 we present a unitized measure of profitability by technology type. This metric represents the present value of EBITDA assuming a discount rate equal to (levered) equity hurdle rate. Results are expressed on a $/kW basis for the amount of nameplate capacity by technology type. Whereas each type of capacity has similar capacity revenue, fixed O&M, and G&A expense components, only the coal-fired steam plants generate substantial profits from energy sales.

Figure 27. Present Value of EBITDA



5.3 FMV by EBITDA Multiple

Average EBITDA over the first five years is summarized in Table 12. Prior to the credit implosion, standard investment multiples used by global investors to derive Enterprise Value for investment-grade enterprises generally ranged between 7x to 9x EBITDA.[58] The FMV of the Mirant fleet ranges from $4.6 billion to $6.0 billion under 7x and 9x, respectively. Primarily in response to the much lower fuel prices used in the Base scenario (S1) and the resultant decline in net profits from energy sales, this represents a $1.5 billion to $1.9 billion decrease in value since the Task 3 Report was prepared.

[58] Unstable capital market conditions have certainly reduced investors' risk tolerance, thereby placing downward pressure on the standard EBITDA multiple used in the Task 3 Report and applied again in this study. To the extent the herd of global investors has thinned and remaining investor risk tolerance has decreased, asset valuations under FMV may reflect a reduced multiple. Derivation and validation of the reduced EBITDA multiple to capitalize the new company has not been part of this inquiry.

Table 12. Summary of EBITDA Multiple Analysis
($ Millions)

	Coal-Fired Steam Units	Oil/Gas-Fired Steam Units	Gas-Fired CTs	Oil-Fired CTs	Total
5-Year Avg EBITDA (per year)	$499.5	$84.2	$54.3	$23.9	$661.9
FMV as Multiple of EBITDA					
7 x EBITDA	$3,497	$589	$380	$167	$4,633
9 x EBITDA	$4,496	$757	$489	$215	$5,957

5.4 FMV Under Net Income Capitalization Approach

Another valuation method is the standard Net Income Capitalization approach. LAI used DCF for this approach, which produces an FMV of $5.063 billion. The DCF approach incorporates a specific projection of operating cash flows derived from the sale of capacity, energy and ancillary services, and also includes all other fixed costs, including G&A loading factors, insurance, maintenance, transaction costs, CapEx, and capital recovery, including depreciation, amortization and taxes. Key financial variables incorporated in the derivation of FMV include a 20-year valuation period, a 50/50 debt/equity ratio, a debt cost rate of 7.0%, and an equity cost rate of 13.5%. We also assume that a willing buyer will complete the HAA CapEx of $125 million required in 2010. We assume a one-time transaction cost of $20 million, which is then capitalized in the derivation of FMV. We have not included any "success fees" or other contingent payments which sometimes appear in the starting capitalization of a new company.

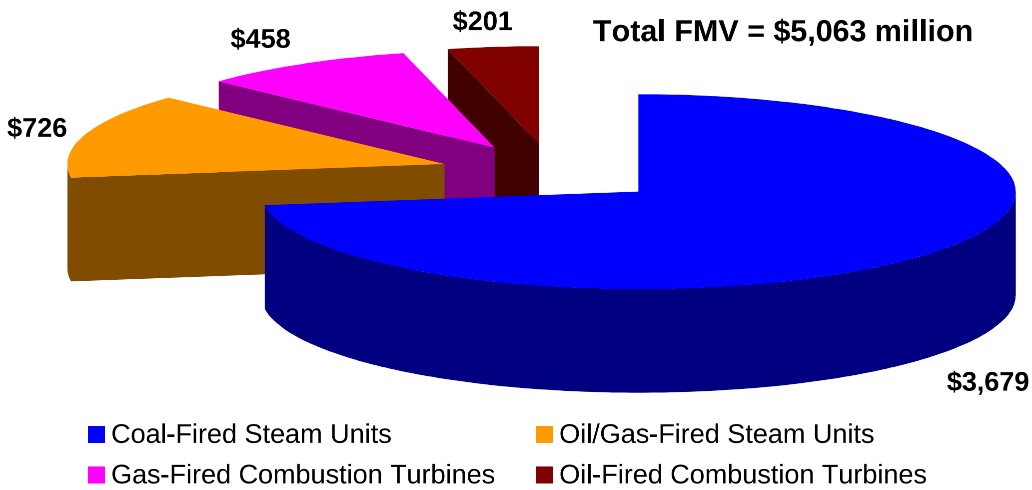
Using the EBITDA forecasts described above and applying appropriate adjustments for tax and leveraging effects to derive cash flow, we have discounted the after-tax equity cash flows. Adjustments for CapEx and transaction costs have been included in the cash flows in order to yield the target return on equity. This calculation is summarized in Table 13, which shows the allocation of FMV to the four generation types.

Table 13. Details of DCF Analysis

	Coal-Fired Steam Units	Oil/Gas-Fired Steam Units	Gas-Fired CTs	Oil-Fired CTs	Total
Capacity (MW)	2,473	1,224	682	309	4,688
% of Total	*52.8%*	*26.1%*	*14.5%*	*6.6%*	*100.0%*
Discounted 20-year Cash Flows *($ Millions)*					
Energy, A/S and Uplift Revenue	10,386	154	173	0	10.712
Fuel Expense	(3,869)	(114)	(101)	0	(4,085)
Variable O&M Expense	(2,037)	(18)	(19)	0	(2,074)
Emission Expense	(1,906)	(17)	(14)	0	(1,937)
Net Energy Margin	2,574	4	39	0	2,616
Capacity Revenue	1,754	888	454	216	3,312
Fixed O&M Expense	(258)	(128)	(10)	(5)	(400)
Subtotal	4,070	765	482	212	5,528
% of Total	*73.6%*	*13.8%*	*8.7%*	*3.8%*	*100.0%*
G&A Expense (Allocated)	(173)	(32)	(20)	(9)	(235)
EBITDA	3,897	732	462	203	5,294
Tax, Leverage Effects	(20)	(4)	(2)	(1)	(27)
Cap Ex Effects	(184)	0	0	0	(184)
Subtotal	3,694	728	459	202	5,083
Less Allocated Transaction Cost	(15)	(3)	(2)	(1)	(20)
Total FMV	**3,679**	**726**	**458**	**202**	**5,063**
% of Total	*72.7%*	*14.3%*	*9.0%*	*4.0%*	*100.0%*
FMV per kW	*$1,488*	*$593*	*$671*	*$650*	*$1,080*

The $5.06 billion FMV under DCF equates to an EBITDA multiple of 7.57x, well within the 7x to 9x range applied above. The coal-fired capacity is valued at a multiple of 7.36x, while the oil/gas-fired steam unit, gas-fired CTs, and oil-fired CTs are valued at multiples of 8.62x, 8.42x, and 8.42x, respectively. The lower relative valuations of the coal capacity reflects a combination of the incremental CapEx assigned to the coal units and to gradual shifts in relative EBIDTA over the longer 20-year horizon. Figure 28 shows the contributions to FMV by type of asset.

Figure 28. FMV by Generation Type



5.5 Conclusion

While there is substantial uncertainty in the actual FMV estimate, we have used the $5.06 billion value as the primary driver of the starting rate base in order to measure the dispersion of ratepayer benefits under either IOU or Authority ownership of the Mirant assets in Maryland. A large portion of the FMV of the Mirant assets is ascribable to the capacity value of the fleet, about two-thirds of the total FMV. In deriving FMV, LAI has incorporated the full intrinsic value of capacity with projected UCAP prices that assume a rational market in equilibrium through 2029. Consequently, UCAP clearing prices equal Net CONE in the RTO for the majority of the forecast period.

As discussed in Section 4.6.3, global investors are likely to be mindful of business cycle and generation investment considerations causing UCAP clearing prices to deviate from Net CONE for a substantial portion of the valuation period, thereby placing downward pressure on FMV. Global investors would be unlikely to bank on 100% of the intrinsic value of capacity in deriving the enterprise value of the Mirant fleet. Under these circumstances, the FMV of the Mirant fleet may therefore be lower than the expected value used in this study. Since the use of the UCAP price forecast under equilibrium assumptions has little or no bearing on the risk-adjusted distribution of EVAs, LAI has used higher capacity values under the equilibrium assumption about the timing and amount of new resource additions rather than undertake a more complex analysis of business cycles in the PJM market.

6 ECONOMIC VALUE ADDED METHOD, DATA, AND RISK METRICS

This section describes the probabilistic evaluation method used to calculate EVA, the measure of net economic benefits or costs for Maryland ratepayers. The probability distribution data and assumptions used for each modeled source of uncertainty are described in Section 6.2 and 6.3. The scenarios are combined in a probabilistic model described in Section 6.1 to produce a distribution of EVAs for the contemplated transaction. The shapes of the upper and lower "tails" of the EVA distribution reveal the likelihood of good or bad outcomes from a ratepayer's perspective. Risk measures are defined in Section 6.4. Results of the probabilistic EVA analysis and various measures of risk are presented in Section 7.

6.1 Probabilistic Evaluation Method

LAI's probabilistic analysis uses Monte Carlo simulation analysis, a relatively standard method used by utilities, banks, and investors to "stress test" the quality of expected financial results. By generating random outcomes of uncertain variables characterized by defined probability distributions, we are able to produce a spectrum of financial outcomes at different confidence levels in order to chart the relative likelihood of a much higher or lower EVA than the expected outcome. There are two sets of uncertainty factors: primary variables that are the key drivers of the MarketSym model – fuel prices and GHG policy – and secondary variables. The secondary variables encompass capacity prices associated with PJM's RPM, a number of financial uncertainty factors that the IOU or the Authority would experience as a result of the return to rate base regulation, and performance considerations related to the coal plants, in particular. The probabilistic modeling procedure "maps" the randomly simulated primary drivers of fuel prices (indexed to the crude oil price) and GHG policy (which determines CO_2 allowance prices) for 1,000 possible "futures" to the set of deterministic scenarios tested in MarketSym and the capacity pricing model under the RPM. The mapping procedure uses linear interpolation or extrapolation of the asset cash flows from the nearest two deterministic scenarios to estimate the cash flow for each random "future."

A high-level model and data flow diagram of the integrated probabilistic analysis modeling is shown in Figure 29. Major categories of input data and intermediate results are shown in the blue boxes, final reported results in green boxes, and the integrated set of models and calculation procedures in the grey boxes. The process starts at the top of the diagram, depicting four oil price cases and two GHG policy cases that have been combined into seven scenarios modeled with the hourly chronological MarketSym model and LAI's annual RPM capacity price model.

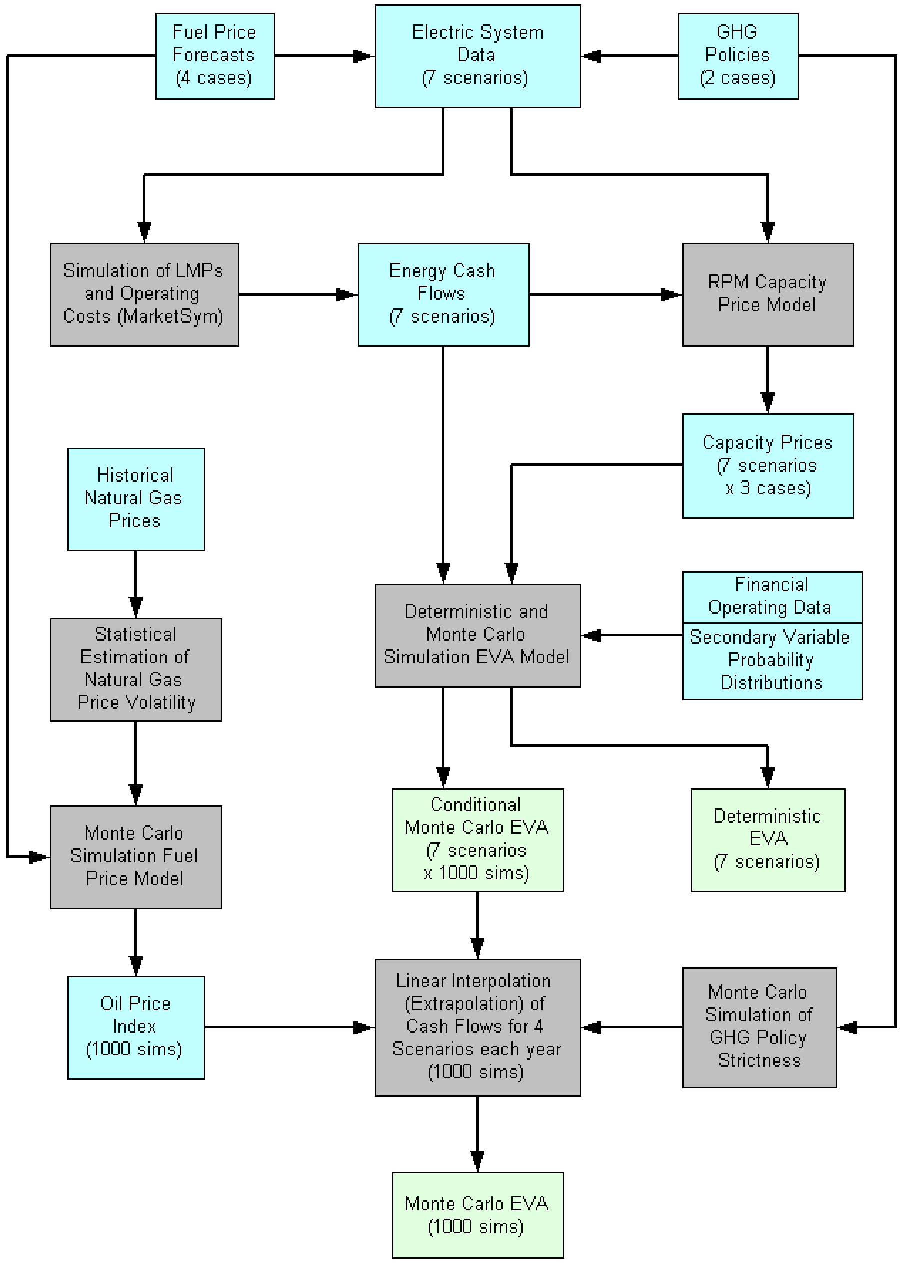
- The forecast of the energy and capacity revenues and expenses, plus other financial and operating data for the Mirant assets, were incorporated into the EVA model to produce a set of seven deterministic scenario EVA results.

- A second set of EVA results was produced by running 1,000 Monte Carlo simulations with the defined probability distribution parameters for the secondary uncertainty factors for each of the seven scenarios. These latter results are termed "conditional" EVA results since each set of 1,000 EVA values depends upon the given fuel price and GHG policy assumptions for the particular scenario.

- A third set of EVA results was produced by also applying 1,000 Monte Carlo simulations to the primary uncertainties of fuel prices and federal GHG policy.

The specific models used for simulating fuel prices and GHG policy are discussed in Section 6.2. That section also describes how the continuous random variables for the oil price index and the CO_2 allowance price index were used to estimate the EVA for each simulated trajectory, based on a weighted average of the discrete scenarios.

Figure 29. Probabilistic Analysis Data Flows and Models Integration



6.2 Primary Uncertainty Factors – Market Economic Variables and Data

As explained in Section 4, the key drivers of uncertainty across the seven discrete scenarios modeled with MarketSym and LAI's capacity pricing model are oil prices and pending federal GHG policy, reflected in the level of CO_2 allowance prices. The probabilistic analysis allows each of these two sources of uncertainty to be simulated as continuous variables with 1,000 Monte Carlo random scenarios.

In the probabilistic analysis, oil prices are simulated as a stochastic process. This means that the price each year is a function of the price in the preceding year as well as a random deviation. In contrast, random sampling of possible federal GHG legislation and the resulting trajectory of future CO_2 allowance prices is done once, rather than annually. The different treatment of CO_2 allowance price levels is because we have less information about the timing and outcome of possible federal GHG legislation over the next few years.[59] Simulated random fuel prices were assumed to be independent of, or uncorrelated with, random GHG policy strictness. The fuel prices represent commodity costs exclusive of any future federal legislation that imposes CO_2 allowance costs or a carbon tax.

6.2.1 Probabilistic Factors for Fuel Prices

LAI made the following assumptions regarding fuel price uncertainty over the study period:

- The EIA Reference Case crude oil price projection for 2015 to 2029 was used for the expected or average price in our Monte Carlo simulation.
- The February 20, 2009, NYMEX futures strip of crude oil prices for 2009 to 2014 was used to update the earlier NYMEX strip (January 29, 2009) used in the discrete scenario simulation modeling. On February 20, 2009, the average of the monthly futures prices for the balance of 2009 was trading down over 12% from three weeks earlier, but the calendar year average price decline for 2010 to 2014 was smaller. Using the updated NYMEX futures does not introduce any bias in the derivation of probabilistic financial results since the probability distribution remains unchanged.
- The trajectory of crude oil prices in any simulation determined natural gas prices based on the OGPR as described in Section 4.3. Random fuel prices were simulated based on the long-term volatility of natural gas, modeled with a continuous lognormal distribution. Natural gas is most frequently the fuel of the marginal generation unit that determines electric energy prices in SWMAAC. It is therefore preferable to quantify fuel price uncertainty around natural gas prices in the probabilistic model.
- LAI statistically estimated the long-run rate of natural gas price volatility and its rate of decay over time (reflecting a volatility "curve"), using historical annual data for U.S.

[59] It is unrealistic to develop a quantitative simulation model to forecast events that we have little to no information about, such as a future ratcheting down of the federal GHG cap, interaction of the U.S. market with international GHG programs, or new technologies that may influence the future level of CO_2 allowance prices. Therefore, once a CO_2 allowance price level is selected, the shape of the trajectory is fixed.

average annual real (inflation-adjusted) prices paid by the electric power sector for the period 1984 to 2007, and a linear regression model. The estimated annual rate of natural gas volatility was 15.27% and the annual rate of mean reversion was 16.61%.[60]

- The graph of a sample of 60 (out of 1,000) random oil prices in Figure 30 illustrates how the annual random draws of price deviations result in a fluctuating simulated price path for each scenario. Figure 30 also shows the expected price forecast as the red dashed line. By design, the average of all the Monte Carlo simulated prices in each year equals the expected price forecast, given by the Base oil price scenario. The five probability levels shown as dashed blue lines indicate the price distribution. For example, 10% of prices in each year are expected to be below the P10 line (second from the bottom) and 10% of prices in each year above the P90 line (second from the top).

Figure 30. 60 Sample Oil Price Paths, with Mean and Confidence Levels

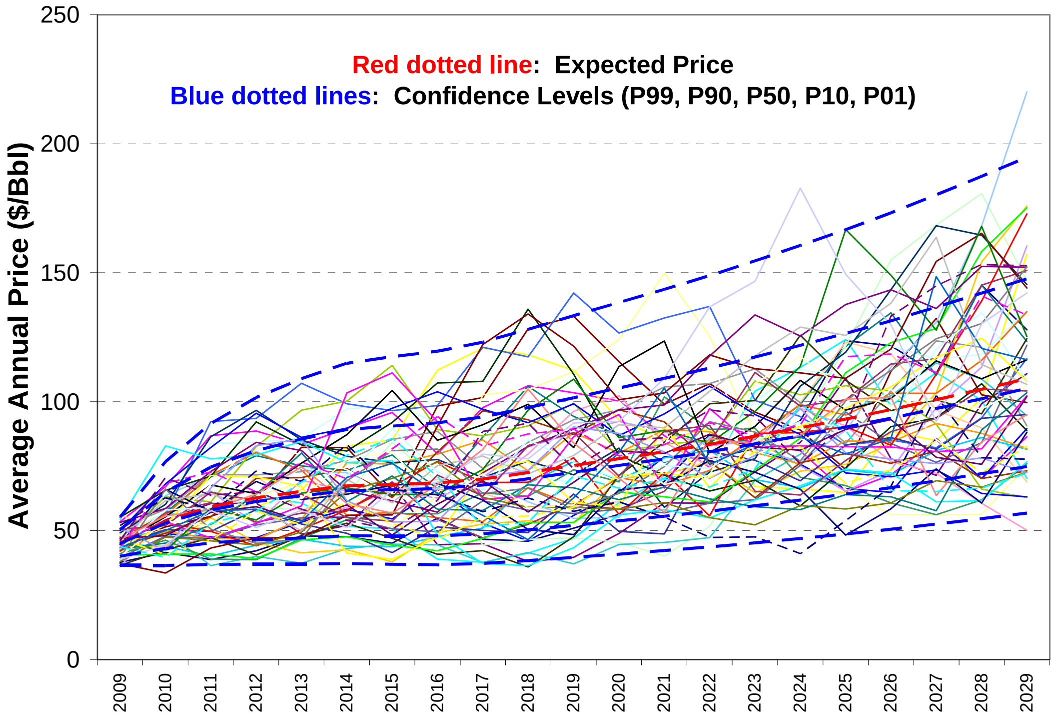


Figure 31 shows how the same stochastic model confidence bands compare to the discrete scenario price paths. Note that the Low and High scenario price forecasts generally fall between the two sets of adjacent confidence bands in most years.[61] Furthermore, the Low and High price scenarios (black lines) fall reasonably near the extremes of the modeled probabilistic price

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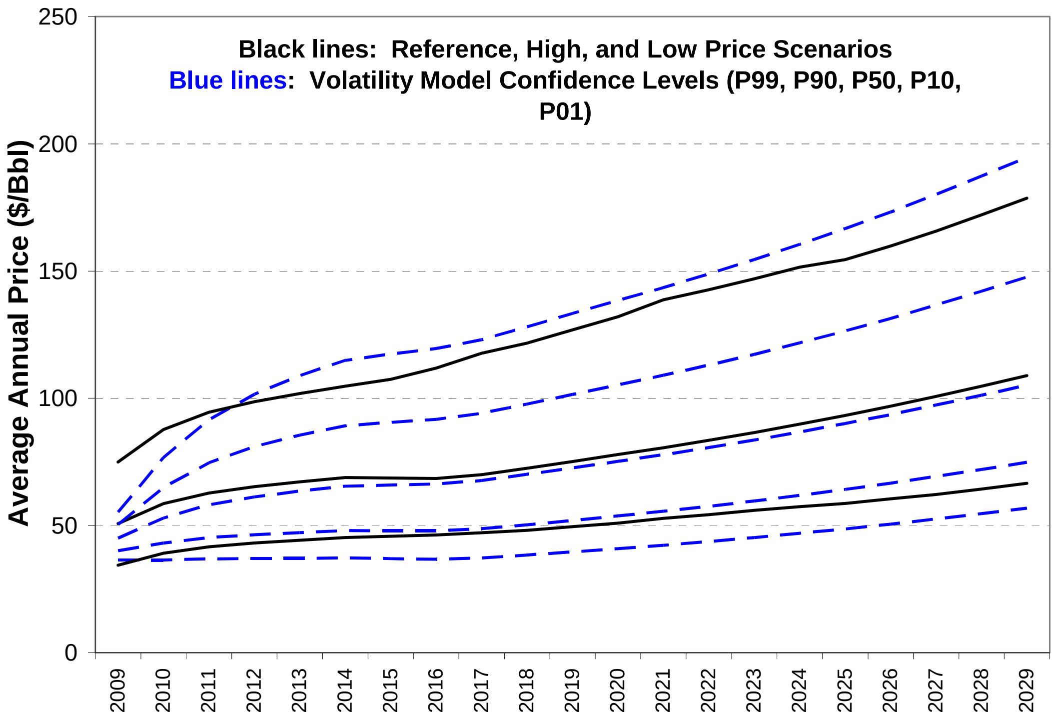
[60] By design, the statistical analysis used average annual prices, rather than daily spot prices, which means that these estimated volatility and mean reversion parameters do not include short-term (less than one year) mean-reverting price volatility. The intent of the probabilistic analysis was to measure long-term uncertainty, and not short-term fluctuations, since the MarketSym and capacity price forecast models used deterministic fuel prices in the seven scenarios simulated.

[61] The confidence level price curves depart from the Low and High price scenario forecasts for the years 2010 to 2014 because the Monte Carlo analysis used the updated NYMEX futures prices for these early years.

distributions. Because the High and Low deterministic price forecasts reasonably bracket most of the Monte Carlo price paths, we can reliably use linear interpolation (extrapolation) to estimate cash flows in the probabilistic EVA analysis. That is, we do not need to extrapolate far beyond the simulated Low and High oil price forecast scenarios.

Figure 31. Oil Price Discrete Scenarios and Confidence Levels



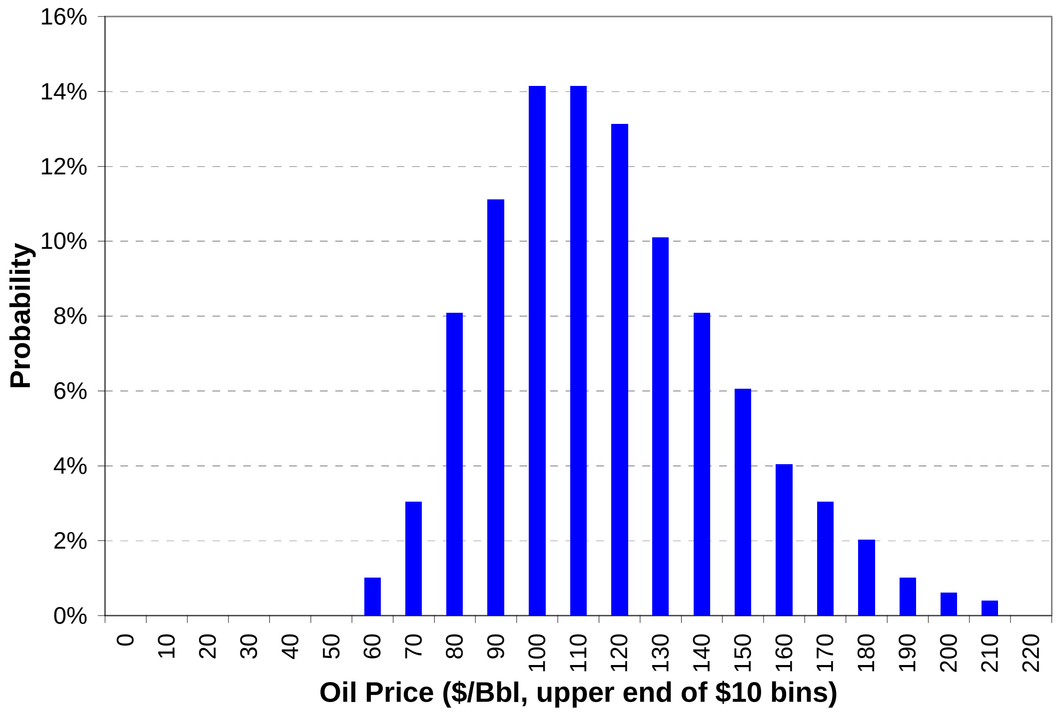
The probability levels that match the three discrete oil price scenarios (Low, Base and High) are shown in Table 14.[62] Note that the Low price scenario is accorded more weight than the High price scenario. This is consistent with the assumption that fuel prices tend to have a lognormal distribution, which skews the distribution toward the low side of the expected (mean) price. In addition, the updated NYMEX futures prices used for 2010 to 2014 expected values in the probabilistic analysis are lower than the prices used in the deterministic Base scenario. For each year simulated, the probabilistic distribution of oil prices retains the same lognormal shape, but the range widens from year to year. For the last year simulated, 2029, a histogram of the oil price distribution appears in Figure 32.

[62] To relate the stochastic oil prices resulting from the volatility model back to the three (Low, Base, and High) discrete oil price scenarios based on the EIA projections, we calculated the equivalent probability weights for the three discrete scenarios that approximately match the stochastic model's lognormally distributed prices. To do so, we first calculated the midpoint prices between adjacent scenario (Low-Base, and Base-High) prices to define three scenario categories. Then we calculated the probability levels that match these two category division prices for each year. Finally, we calibrated the average probability over the study period for each scenario category so that the weighted average closely matched the Base (expected) prices.

Table 14. Oil Price Discrete Scenario Equivalent Probability Weights

Scenario	Probability
High	11%
Base	62%
Low	27%

Figure 32. Oil Price Probability Distribution in 2029



6.2.2 Probabilistic Factors for GHG Policy

The CO_2 allowance price projections for the Moderate and Strict Cap GHG policies discussed in Section 4.2 were combined into probabilistic scenario CO_2 allowance prices for each random scenario, according to the following procedure:

1. A CO_2 allowance levelized price index was used to represent the random GHG policy variable.

2. A triangular probability distribution, characterized by minimum, maximum, and modal (most frequent) values, was assumed for the CO_2 allowance price index variable.

3. For each probabilistic scenario, a random draw on federal GHG policy was taken from this triangular probability distribution.

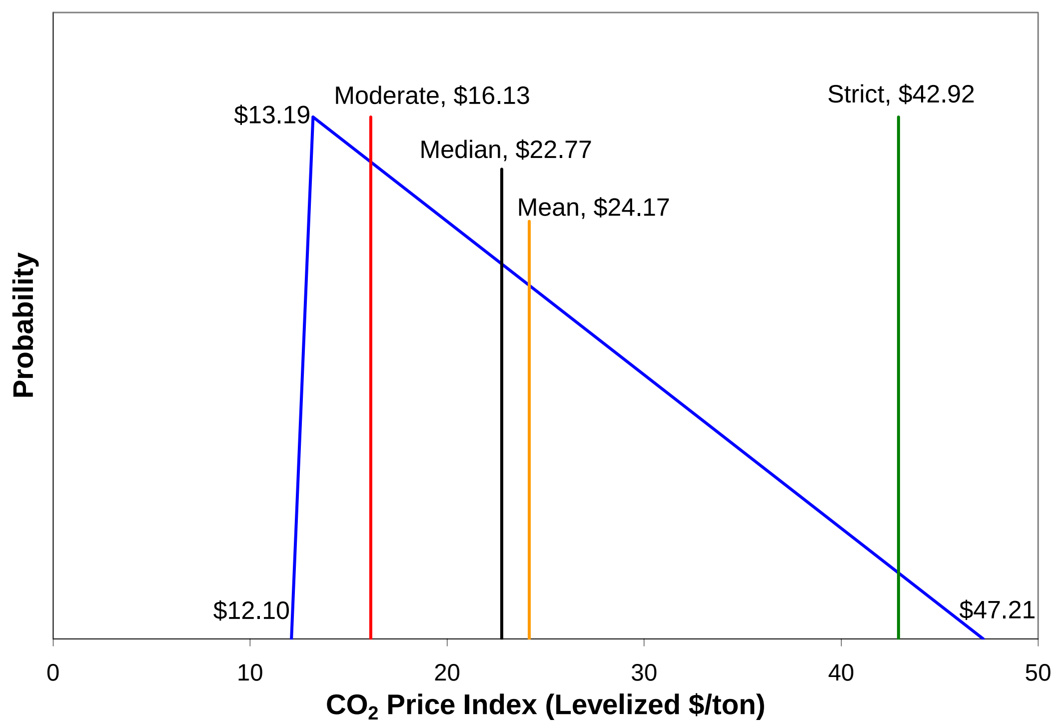
4. The value of one random draw of this CO_2 allowance price index in each probabilistic scenario was used to calculate the linear interpolation (extrapolation) weights of the Moderate and Strict Cap deterministic scenario cash flows.

The location and shape of the triangular probability distribution was determined by the following data assumptions:

- The price index values for the Moderate and Strict Cap CO_2 allowance price forecasts were calculated as their nominal levelized price over the 2010 to 2029 period. The nominal levelized price index values are $16.13/ton of CO_2 for the Moderate Cap policy and $42.92/ton for the Strict Cap policy.
- The minimum CO_2 allowance price index value was assumed to be 75% of the Moderate Cap price index value, or $12.10/ton. The maximum CO_2 allowance price index value that could be simulated was assumed to be 110% of the Strict Cap level, or $47.21/ton.
- The probability for the Moderate Cap scenario was assumed to be 70%, leaving 30% probability for the Strict Cap scenario.

Applying these five parameters (two scenario price index values, minimum and maximum possible price index values, and the Moderate Cap policy discrete equivalent probability) allows the modal price index value to be calculated as $13.19/ton. Although the shape for the continuous triangular distribution appears overly skewed, it results in the same expected (mean) value as for the two discrete scenarios. These assumptions result in the probability density function (PDF) for the CO_2 price index graphed in Figure 33 as the blue line. The expected (mean) and 50% probable (median) price index values are also shown in the graph.

Figure 33. GHG Policy Price Index Probability Density Function and Discrete Scenario Values



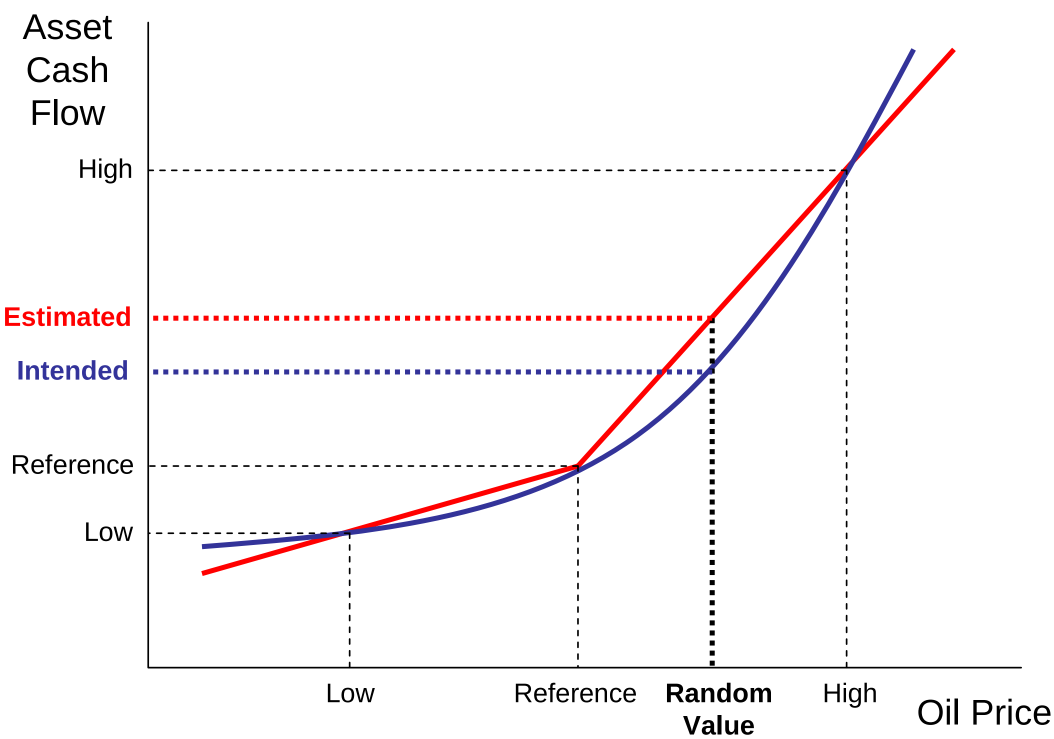
As discussed in Section 4.2, the Moderate and Strict Cap CO_2 allowance price projections were formulated so as to bracket the likely range of outcomes regarding implementation of a federal

GHG control policy. This is why the lowest and highest possible price index values are only slightly below or above the values for these two discrete scenarios.

6.2.3 Monte Carlo Scenario Sampling

For each modeled year in each Monte Carlo simulation, the discrete scenarios are weighted to approximate the annual Mirant fleet cash flow data for the "sampled" simulation. The weighting is based on the sampled crude oil price for each year and the initial CO_2 price index trajectory for the sampled simulation. The sampled crude oil price is compared to the prices representing the discrete scenarios. If the sampled price is below the Base scenario price, then the Base scenario and Low scenario are used for interpolation (extrapolation). If the sampled oil price is above the Base scenario price, then the Base scenario and High scenario are used for interpolation (extrapolation). A weight for each of the two relevant fuel price scenarios is determined, such that the product of the two weights and the corresponding fuel scenario oil prices equals the sampled oil price. This single dimensional interpolation is illustrated in Figure 34.

Figure 34. Mapping of Scenario Cash Flows with Linear Interpolation

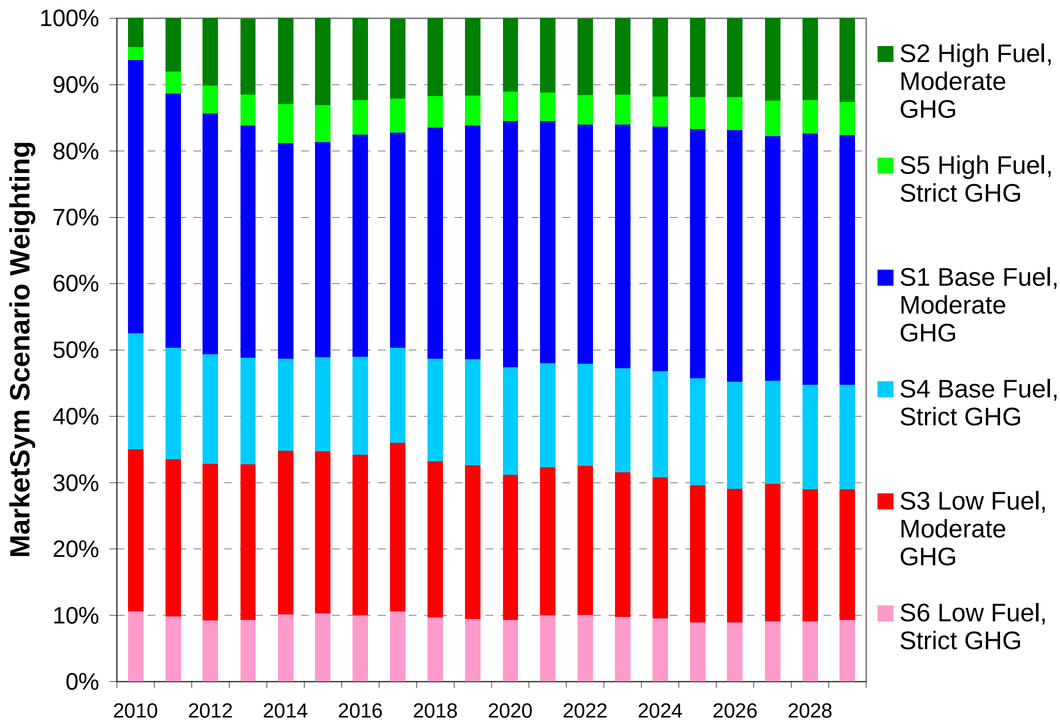


Similarly, the sampled CO_2 price is compared to the prices representing each of the GHG policy scenarios, and a pair of weights is determined such that the product of the weights and the GHG policy scenario prices equals the sampled price. For each year, therefore, four of the six discrete MarketSym scenarios (S1 through S6) are used to interpolate in two dimensions. The weighting factors are applied to the cash flow components from the appropriate discrete scenarios to provide input to the "sampled" simulation.

Figure 35 shows the expected value (mean) weights for each scenario, based on 1,000 Monte Carlo simulations. Note that S7 (Peak Oil, Moderate GHG) is not used in the sampling process.

It is modeled for sensitivity purposes only. S2 and S5, representing High fuel prices, have little weight until 2014. Also, note that the relative weights for Moderate and Strict GHG regulation scenarios are constant for all fuel scenarios.

Figure 35. Mean Weight Factors for Discrete Scenarios



6.3 Secondary Uncertainty Factors – RPM, Financial and Operational Variables and Data

In addition to the primary uncertainty variables – fuel and GHG policy – that are key drivers of energy prices, we consider other financial and operational performance variables that pertain to the PJM capacity market, the operation of the Mirant plants, transaction costs, G&A expenses, and environmental projects. Uncertainties surrounding these variables are independent of the factor inputs to MarketSym and therefore have no direct bearing on energy prices, but they do affect the cash flows of the Mirant fleet. These variables have been treated probabilistically in the EVA model. The probabilities assigned to these variables are based on LAI's best judgment and are neutral, that is, not intended to bias the EVA outcomes to the low or high side.

6.3.1 RPM Revenue Uncertainty

Each of the seven scenarios results in a discrete RPM capacity price forecast due to changes in net EAS revenues and in the schedule of capacity additions. Within each scenario, we capture all the potential sources of capacity price uncertainty (as described in Section 4.6) by altering the starting value of Gross CONE. The uncertainty in capacity price outlook is treated as a discrete probability distribution with three RTO Gross CONE values (high, most likely, and low) and probabilities as indicated in Table 15.[63] A series of annual capacity prices for SWMAAC has been calculated for each of the seven scenarios and under each RPM case, resulting in 21 separate capacity price forecasts.

Table 15. RPM Revenue Probability Data

Case	RTO Gross CONE	Probability
High (+25%)	$156,761/MW-year	10%
Most Likely	$125,409/MW-year	50%
Low (-25%)	$94,057/MW-year	40%

6.3.2 Transaction Cost Uncertainty

In Section 3.3, we estimate the transaction cost associated with acquiring the Mirant fleet to be $20 million. This estimate covers what would normally happen if the Mirant fleet were offered to global investors in a competitive solicitation. This estimate includes bidding, due diligence, legal, and other fees necessarily incurred to complete the transaction. Recognition of transaction costs slightly reduces FMV. Depending on the complexity of the transaction, extent of legal challenges, commercial arrangements, and documentation costs, we expect that transaction costs for the IOU would be $10 million higher. Uncertainty of the buyer-side transaction cost for the IOU has been modeled as a continuous, lognormal probability distribution, with a mean value of $30 million, and standard deviation of $10 million. Uncertainty of the buyer-side transaction cost for ownership by an Authority has been treated similarly, with the same $10 million standard deviation, but a mean value of $40 million to reflect higher Authority-specific costs.

Table 16. Transaction Cost Probability Data

	IOU	Power Authority
Expected Value	$30 million	$40 million
Standard Deviation	$10 million	$10 million

6.3.3 Transition Cost Uncertainty

Acquisition of the Mirant generating assets by any new owner would incur incremental costs to create the management and operational infrastructure needed to insure commercial success, as explained in Section 3.4. We assume in all cases that incumbent plant O&M staff would be retained by the new owner. We have evaluated three primary transition costs: establishing an organizational structure, annual G&A expenses, and annual fees for a short-term banking facility. The impact of uncertain transition costs is tested through a tri-level discrete probability distribution with a deviation of ±$10 million per year, as indicated in Table 17.

[63] RTO values are shown because we expect that UCAP prices in SWMAAC will be based on RPM results for the entire RTO in most forecast years.

- The first transition cost is establishing an organizational structure. We believe the cost would be minimal for an existing merchant generation company, but significant for an IOU or an Authority.
- The second transition cost is annual G&A expense. An existing merchant generator would incur some incremental expense, while an IOU or Authority would incur more substantial G&A expenses.
- The third transition cost is annual bank facility expense, which we believe would not vary significantly for any owner.

Table 17. Transition Costs Probability Data

	IOU	Power Authority
Org. Structure (one-time)	$10 million	$25 million
G&A Expense (annual)	$40 million	$50 million
Bank Facility (annual)	$10 million	$10 million
Base Value (first year)	$60 million	$85 million
Probability of Base Value	*50%*	*50%*
Uncertainty Range (+ / –)	*$10 million*	*$10 million*
High Cost Probability	*25%*	*25%*
Low Cost Probability	*25%*	*25%*

6.3.4 Cost of Capital Uncertainty

As discussed in Section 1.1.4, we estimate the cost of capital for IOU ownership of the Mirant fleet at 6.5% for debt and 10.0% for equity. The uncertainty of the IOU cost of capital has been modeled as a tri-level discrete probability distribution for adders of 25 bp and 50 bp to both the equity return rate and the debt interest rate with defined probabilities, as shown in Table 18 below. We have held constant the 50/50 debt/equity cost ratio in computing the IOU costs of capital.

Table 18. IOU Cost of Capital Probability Data

Case	Debt Rate	Equity Rate	Probability
Most Likely	6.50%	10.00%	50%
Moderate (+25 bp)	6.75%	10.25%	35%
High (+50 bp)	7.00%	10.50%	15%

The cost of capital for Authority ownership has also been modeled as a tri-level discrete probability distribution based on our estimate of 5.6% for the debt interest rate. The uncertainty in the actual Authority cost of capital has been modeled as a discrete probability distribution for adders of 50 bp and 75 bp to represent the potential premium for taxable Authority revenue bonds. The potentially higher cost of GO bonds for other State of Maryland infrastructure projects has not been incorporated in the probabilistic analysis, but is discussed qualitatively in Section 8.3.

Table 19. Power Authority Cost of Capital Probability Data

Case	Debt Rate	Probability
Most Likely	5.60%	50%
Moderate (+50 bp)	6.10%	35%
High (+75 bp)	6.35%	15%

6.3.5 Capital Expenditure Schedule Index

A schedule of CapEx for periodic major equipment overhauls to maintain the fleet in service, based on a typical maintenance schedule and foreseeable environmental requirements, was used in deriving the FMV. While it is unlikely that the actual CapEx will be lower, it is possible that more stringent environmental requirements may mandate additional CapEx over the study period, with corresponding increases to fixed or variable O&M costs and performance. Three cases with discrete probabilities have been developed, as follows:

- The most likely case is represented by the CapEx schedule in the FMV calculation.
- A high case envisions that each of the Mirant coal plants will be required under a MACT standard to reduce mercury emissions by more than 90% by 2014. Incremental CapEx to install and operate ACI of $3/kW and fixed O&M of $3/MWh, as described in Section 1.8, are included in this case. In addition, we assume that each of the Mirant coal plants is required to retrofit their once-through cooling water systems with a fine-mesh screen system or similar technology to minimize fish impacts at the intake by 2014. CapEx are assumed to be the values estimated by the EPA as discussed in Section 1.10. We applied the average of the cost (on a per kW basis) published for Chalk Point and Morgantown to Dickerson. We have assumed that the fine-mesh screens or comparable technology do not have a significant effect on operating costs or plant performance.
- A very high case envisions that each of the Mirant plants coal installs ACI for mercury removal, as in the high case, and also must replace their once-through cooling water systems with a closed loop system to comply with a very stringent interpretation of BTA under Section 316(b) of the Clean Water Act. Due to the potential system reliability issues associated with blanket federal enforcement of a strict BTA standard reported by NERC, we consider the probability of this outcome to be low. The cost of a closed loop system is based on the estimate for Dickerson. We assume that the once-through cooling system reduces plant output by 4%, consistent with the NERC assumption described in Section 1.10. We also assume that the cooling water system could be replaced without a significant amount of downtime to the plant.

Details on each case are provided below in Table 20.

Table 20. Capital Expenditure Case Data

	Base	High	Very High
Assumed Probability	40%	55%	5%
ACI (Year Scheduled)	n/a	2014	2014
ACI Capital ($/kW)		$3.00	$3.00
ACI O&M ($/MWh)		$3.00	$3.00
316(b) (Year Scheduled)	n/a	2014	2017
316(b) Capital ($/kW)		$7.50	$280
316(b) Output Loss		0%	4%

6.3.6 Fixed O&M Case Index

While fixed O&M expenses were considered as a possible source of uncertainty in the estimation of EVA, we have determined that the estimates used in the FMV calculation are reasonable and that further refinement and probabilistic treatment are unnecessary. The fixed O&M levels in the EVA calculations are deterministic and correspond to those used in the FMV calculation.

6.3.7 Coal Capacity Loss Index

The potential loss of capacity, particularly coal-fired capacity, due to extended forced outages or major accidents as described in Section 8.4 was considered a source of uncertainty in the estimation of EVA. We have determined that, while any generating unit is subject to the risk of a major malfunction, it is unlikely that common mode failures would occur at all or even a majority of the Mirant coal-fired units simultaneously. Therefore, we have limited the testing of this variable to a low-probability occurrence of a partial loss of coal capacity for a limited time. Specifically, we assumed that 25% of the Mirant coal capacity is taken out of service for a year. The year we selected is 2018, admittedly an arbitrary choice. We have assigned a probability of occurrence equal to 5%.

6.4 EVA Risk Metrics

Risk is defined for the purpose of the probabilistic EVA analysis as a "bad" or unfavorable outcome relative to the expected benefit of the bargain, once either the IOU or the Authority completes the acquisition of the Mirant fleet under FMV. Unlike risk, uncertainty can result in either "good" or "bad" outcomes. In this study we quantify the risk and reward associated with the return to rate base regulation by systematic testing of the uncertainty factors. While uncertainty regarding a particular variable is the same regardless of one's perspective, there is no bright line regarding the risk-reward tradeoff – risk tolerance is in the eye of the beholder. Therefore, LAI has calculated an array of customized risk metrics in order to give the Commission the quantitative information and insights needed to support informed decision-making.

Many measures of risk are used in economic evaluation of financial planning decisions. Multiple risk measures or metrics are reported in Section 7 since no single measure captures all aspects of risk that are important from the ratepayer's perspective.

The common statistical measure of dispersion is standard deviation, which includes both positive and negative deviations from the expected value, so it measures both good and bad outcomes, including potentially extreme occurrences. However, standard deviation is not the preferred risk measure for this study. For distributions of uncertain cash flows that closely approximate a symmetric distribution, such as the normal (bell-curve) distribution, standard deviation is a good measure of risk. On the other hand, for a portfolio of generation assets like the Mirant fleet in Maryland that faces multiple sources of uncertainty, each of which may have different distribution shapes, non-linear correlations, and serial correlation over time, the distribution of potential net cash flows may be decidedly skewed and positively correlated between time periods. While LAI focuses on downside risk measures, standard deviation is also reported because it also measures upside reward, that is, "earnings surprises" or good outcomes from the standpoint of the IOU's retail customers.

Three conceptually distinct but related downside risk metrics are calculated and reported as illustrated in Figure 36, which represents uncertain cash flows as a PDF graph. The most commonly applied downside risk measure is VaR, the maximum probable shortfall in cash flow from a defined threshold down to a specified confidence level in the lower tail. In this study, the probable shortfall in cash flow is the EVA differential between the expected financial results over 20 years and the simulated occurrence(s) at the stated confidence level. Figure 36 shows a specific VaR measure at a 95% confidence level (VaR95), so that the 5% left tail of the PDF is excluded.[64] For a normal distribution, VaR data for any confidence level allows one to calculate VaR for any other confidence level. However, the more the shape of the outcomes departs from a normal distribution, the more important it is to report VaR for multiple confidence levels. A higher confidence level VaR will result in fewer very bad outcome surprises by including more of the lower tail, but it can also exaggerate the size of risk under most outcomes that are worse than the risk threshold probability.

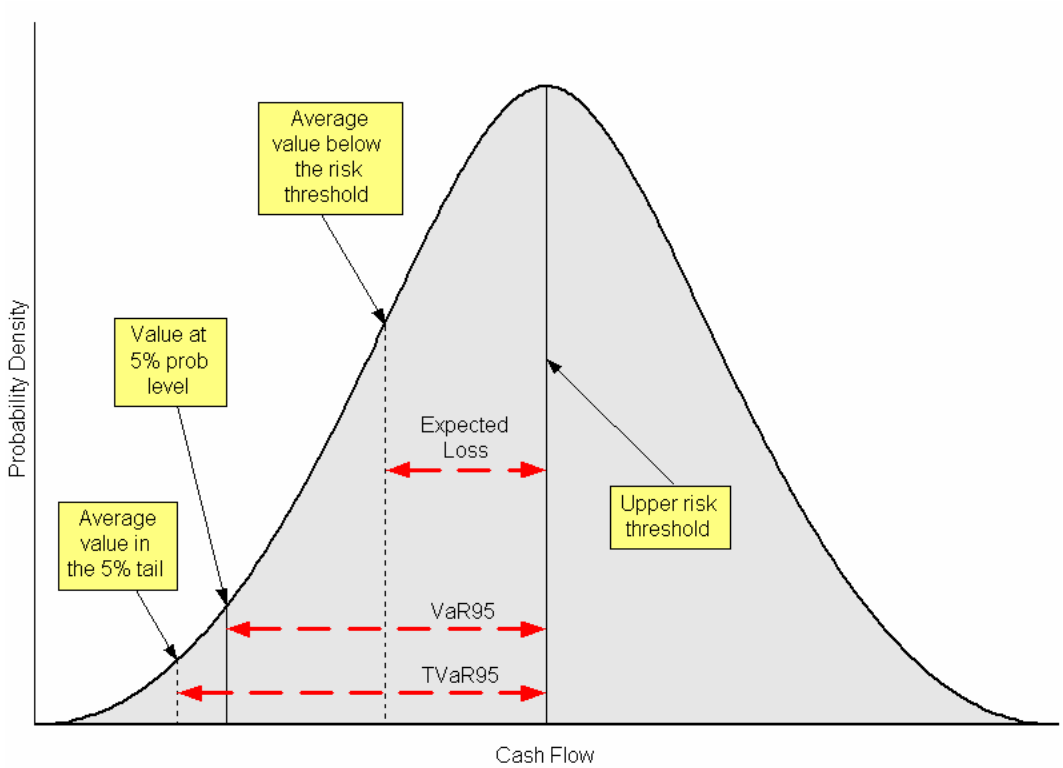
A weakness of traditional VaR is that it completely ignores the size of potential losses in the tail region. The left-hand tail in Figure 36 encompasses the worst outcomes. To the extent there is a significant chance that very bad economic outcomes may take place, it is important to report exactly how bad "bad" can be, and the related probability that such negative outcomes will occur. Depending on the shape of the distribution, some bad outcomes could greatly exceed the VaR value. An alternative measure of downside risk that includes consideration of losses that exceed the defined maximum probable loss is known as tail VaR (TVaR).[65] TVaR measures risk down to the average value of outcomes conditional on being worse than the defined confidence level. The magnitude of TVaR is always larger than for VaR when they are based on the same risk threshold and confidence level. In considering the relevance of TVaR it is important to note that for different tail shapes, for example, a short, thick tail versus a long, thin tail, TVaR records a larger value for the long, thin tail while VaR is unchanged. This makes TVaR a useful risk

[64] Other commonly used confidence levels are 99% and 90%.

[65] TVaR is also referred to as Conditional VaR.

metric in the context of reporting the magnitude and likelihood of an extremely bad outcome from the vantage point of the ratepayer.

Figure 36. Comparison of Value-at-Risk, Tail Value-at-Risk, and Expected Loss



A third downside risk measure shown in Figure 36 is usually called "Expected Loss" or "expected regret." Expected Loss is similar to TVaR in that it also measures the average value of outcomes conditioned on their probability being less than a defined probability. The difference is that this conditional probability is defined to be the same as the risk threshold. The Expected Loss metric considers all the bad outcomes in a weighted average measurement, rather than just the very bad outcomes, as for TVaR.[66] LAI reports the expected loss metric in Section 7 in order to provide more insight into the composition of potential bad outcomes.

The threshold for these three downside risk metrics is often defined relative to the probabilistic mean (average) or median (value at the 50% probability level) of the distribution. Alternatively, a fixed value may be used. Since the point where customers will start to be significantly harmed by bad outcomes is likely close to the "no harm" or zero loss point, we quantify TVaR and expected loss with the risk threshold set at zero. This distinction between relative and fixed upper risk thresholds is illustrated in the graph below for the TVaR measure, but it applies equally to all three downside risk metrics. Figure 37 shows how VaR measures can be determined relative to a predetermined value (such as zero) or against the mean.

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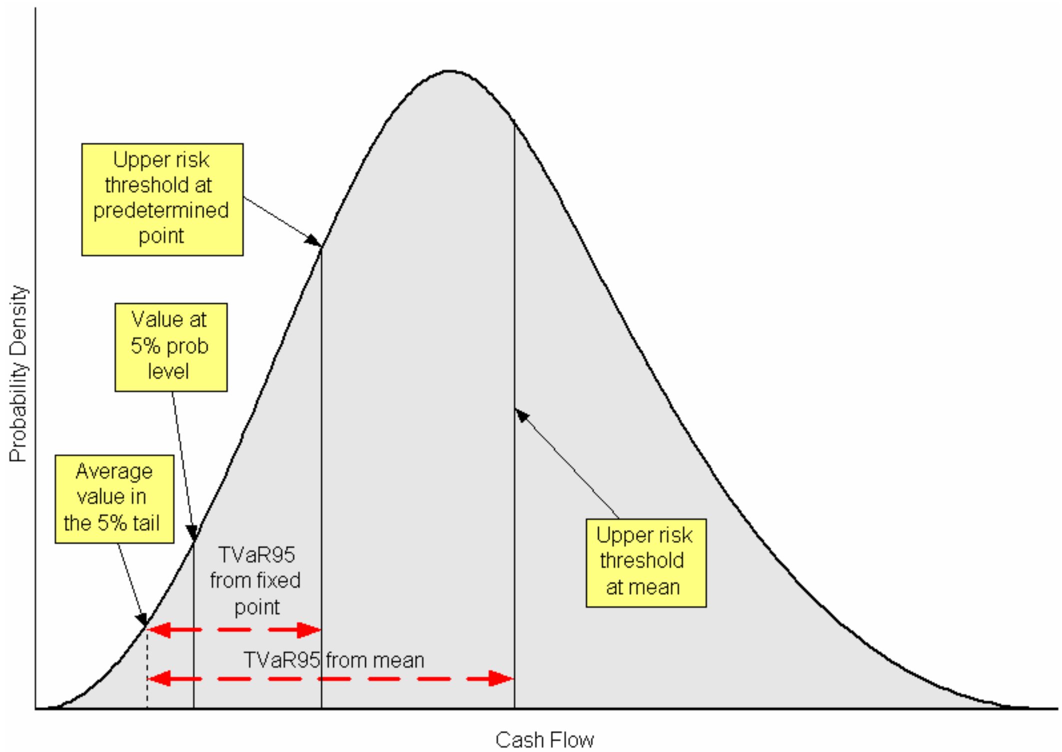
[66] Another intuitive advantage of expected loss is that it is the same definition of risk as used by the insurance industry, which is also the same as the calculation of the value of a "put" option in the financial industry.

Figure 37. Comparison of Tail Value-at-Risk Defined for Variable or Fixed Upper Risk Threshold



In summary, LAI reports the following array of risk measures in Section 7:

- Standard deviation,
- Expected loss measured from the expected value of benefits,
- Expected loss measured from the zero benefit threshold,
- VaR95 measured from the expected value of benefits,
- Var95 measured from the zero benefit threshold,
- TVaR95 measured from the expected value of benefits,
- TVaR95 measured from the zero benefit threshold, and
- Probability of loss.

7 ANNUAL NET BENEFIT AND ECONOMIC VALUE-ADDED RESULTS

This section presents the results of the probabilistic analysis of the return to rate base regulation, including three types of analyses of annual net benefit and EVA under the IOU and Authority ownership structure. First, deterministic results are compared for the seven discrete scenarios in Section 7.1. Second, the seven scenarios are analyzed using Monte Carlo simulation analysis of the secondary variables in Section 7.2. Third, and most importantly, Monte Carlo simulation is applied to the primary risk drivers of fuel prices and GHG policy, combining the probabilistic treatment of the scenarios with the secondary risk drivers in Section 7.3.

In Section 7.3 we also provide a number of statistical measurements that capture the inherent risk of returning to rate base regulation under each ownership structure.

7.1 Deterministic Results

7.1.1 Annual Net Benefits

Annual net benefits for the IOU ownership case under Base (S1) market variables and the base or default values for all secondary variables are shown in Figure 38. Note that annual net benefit is negative through 2013; thereafter, the annual net benefit becomes significantly positive. Capital recovery charges decrease over time, representing return on a depreciating rate base. Net energy revenue represents EAS revenues, less fuel and other variable costs. Capacity revenue is generally larger than net energy revenue in most years.

Annual net benefits for the Authority ownership case under Base (S1) market variables and the base or default values for all secondary variables are shown in Figure 39. Note that annual net benefit is low or negative through 2011; thereafter, annual net benefit becomes significantly positive. Capital recovery charges also decrease steadily over time, representing return on a depreciating rate base.

Figure 40 compares the annual net benefits for all seven scenarios under IOU ownership, assuming base or default values for all secondary variables. All scenarios have negative annual net benefits for at least the first two years. S7 (Peak Oil, Moderate Cap GHG) shows rapidly climbing positive annual net benefits after 2012. S6 (Low Fuel, Strict Cap GHG) shows negative annual net benefits in all years, while S4 (Base Fuel, Strict GHG) and S3 (Low Fuel, Moderate Cap GHG) show negative annual net benefits for the first several years.

Figure 41 compares the annual net benefits for all seven scenarios under Authority ownership. For all scenarios, the deterministic annual net benefit for Authority ownership is higher than the corresponding IOU result for those early years while the capital recovery charges remain high. S2 (High Fuel, Moderate Cap GHG) and S7 show positive net benefits in all years, and only S6 (Low Fuel, Strict Cap GHG) shows negative annual net benefits in almost all years.

Figure 42 compares deterministic annual net benefits for the two ownership structures under S1.

Figure 38. Annual Net Benefits – IOU Ownership, S1

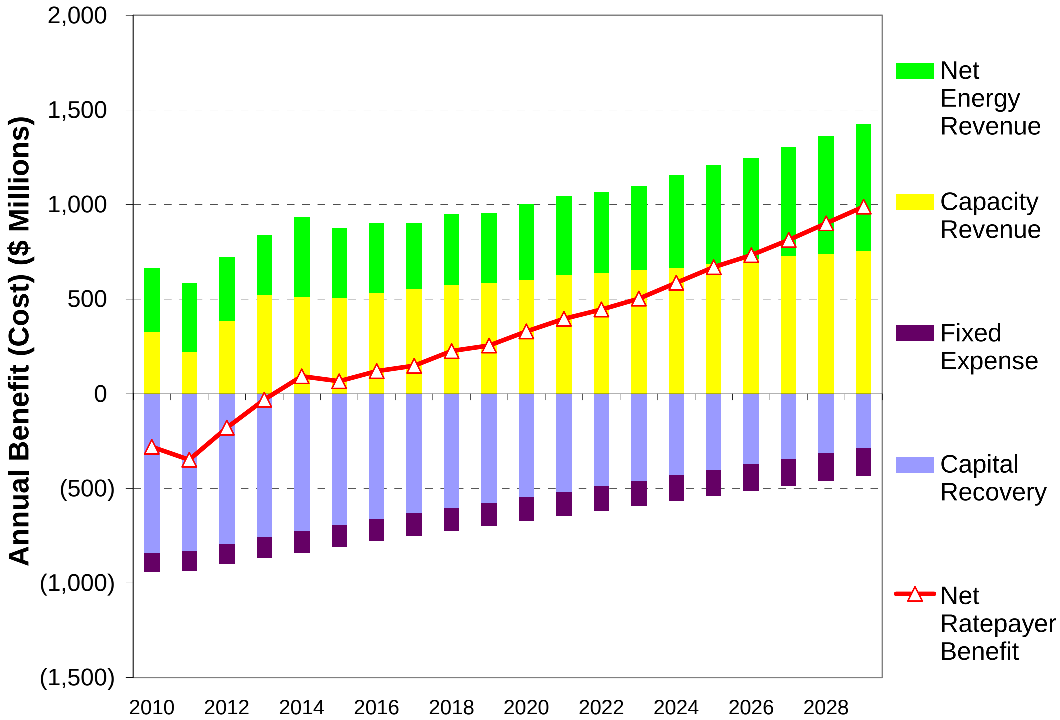


Figure 39. Annual Net Benefits – Authority Ownership, S1

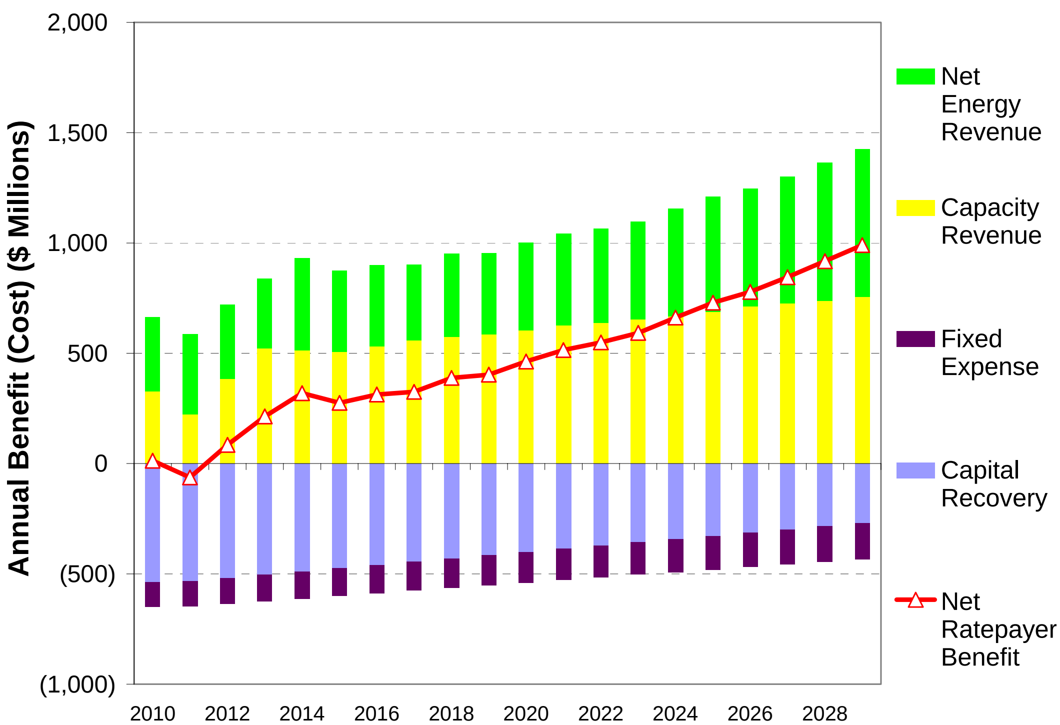


Figure 40. Annual Net Benefits – IOU Ownership

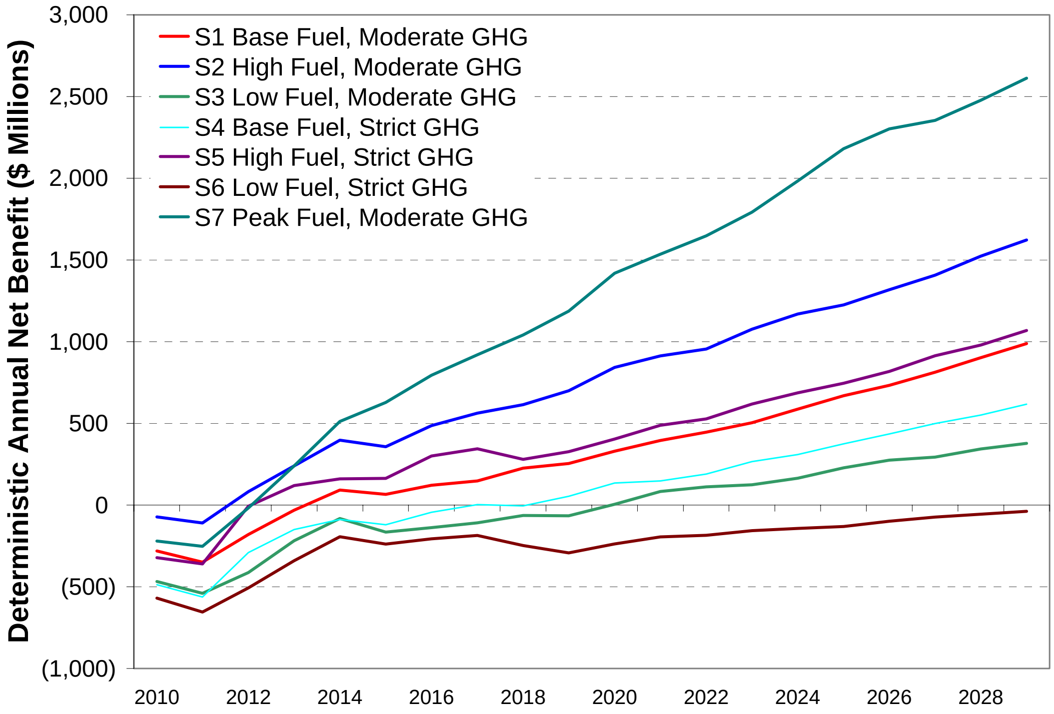


Figure 41. Annual Net Benefits – Authority Ownership

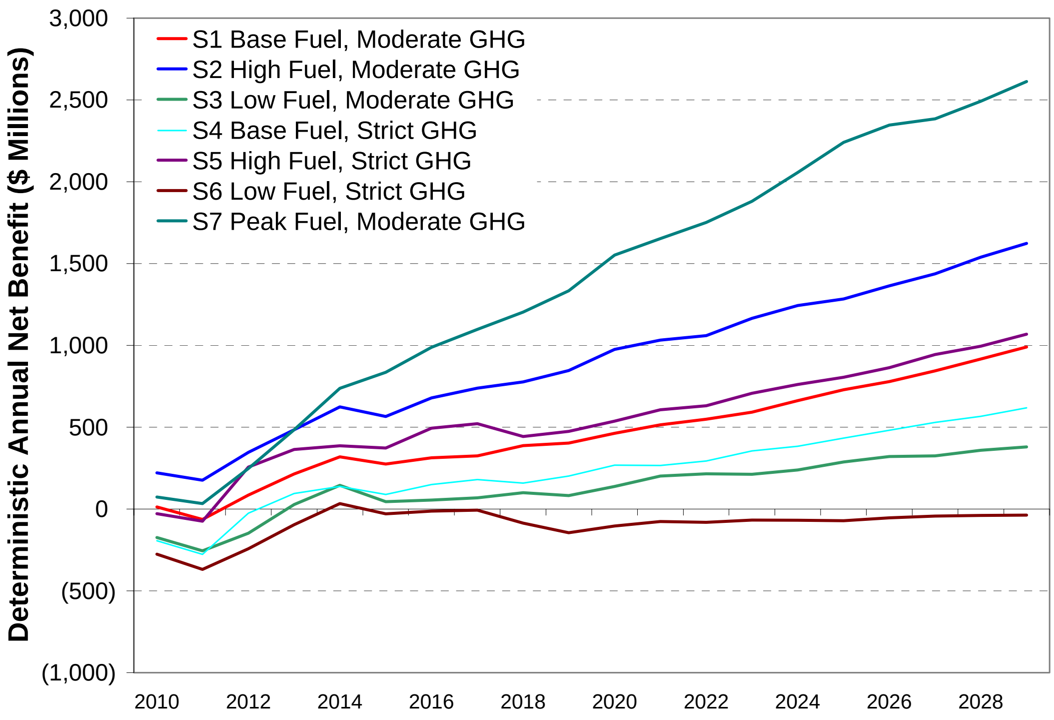
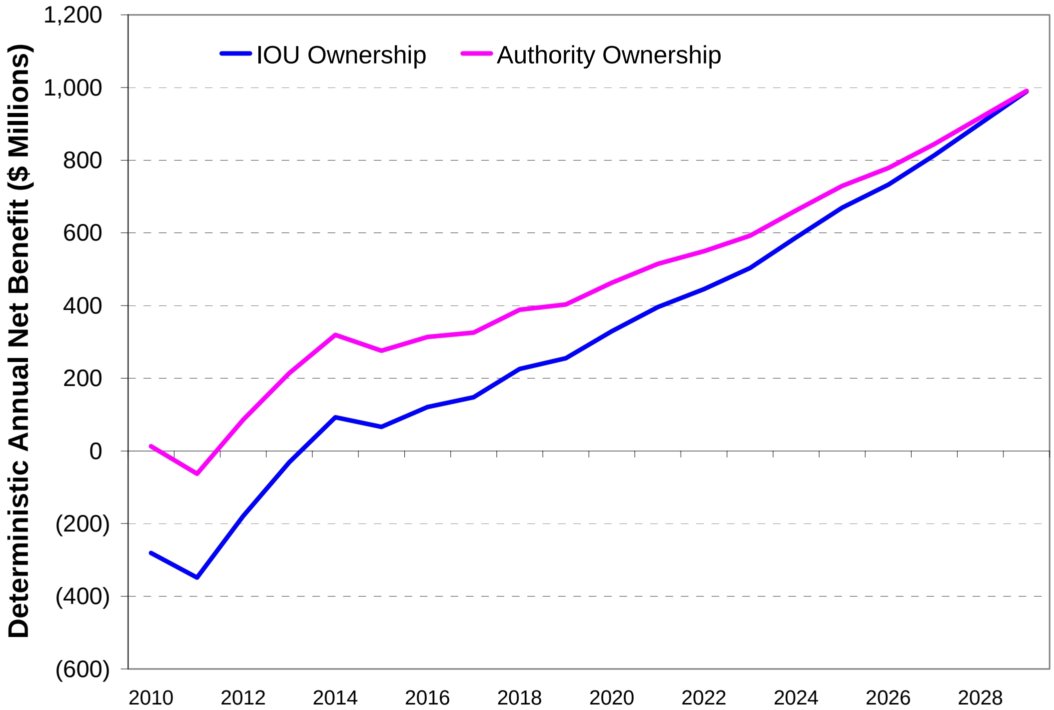


Figure 42. Comparison of Deterministic Annual Net Benefits



7.1.2 <u>Economic Value Added</u>

EVA is calculated as the present value of the annual net benefits. Deterministic EVA components for the IOU ownership structure for the seven scenarios are shown in Figure 43. Deterministic EVA is positive for S1, S2, S5, and S7, and negative for S3, S4, and S6.

Deterministic EVA components for the Authority ownership structure for the seven scenarios are shown in Figure 44. Deterministic EVA is positive for all scenarios except S6, but only slightly positive for S3 and S4.

The relationship between deterministic EVA and the primary variables defining the scenarios is shown in Figure 45 for IOU ownership and in Figure 46 for Authority ownership.[67]

EVA for Authority ownership is roughly $1.8 billion higher than the EVA for IOU ownership in each scenario. For each ownership form, the Strict GHG scenarios result in lower EVAs than the Moderate GHG scenarios for the same crude oil price scenario. For the same GHG scenario, higher fuel prices consistently result in higher EVA.

[67] S7 is not included in these figures since it is not used in the probabilistic modeling in successive steps of the analysis.

Figure 43. Deterministic EVA by Component – IOU Ownership

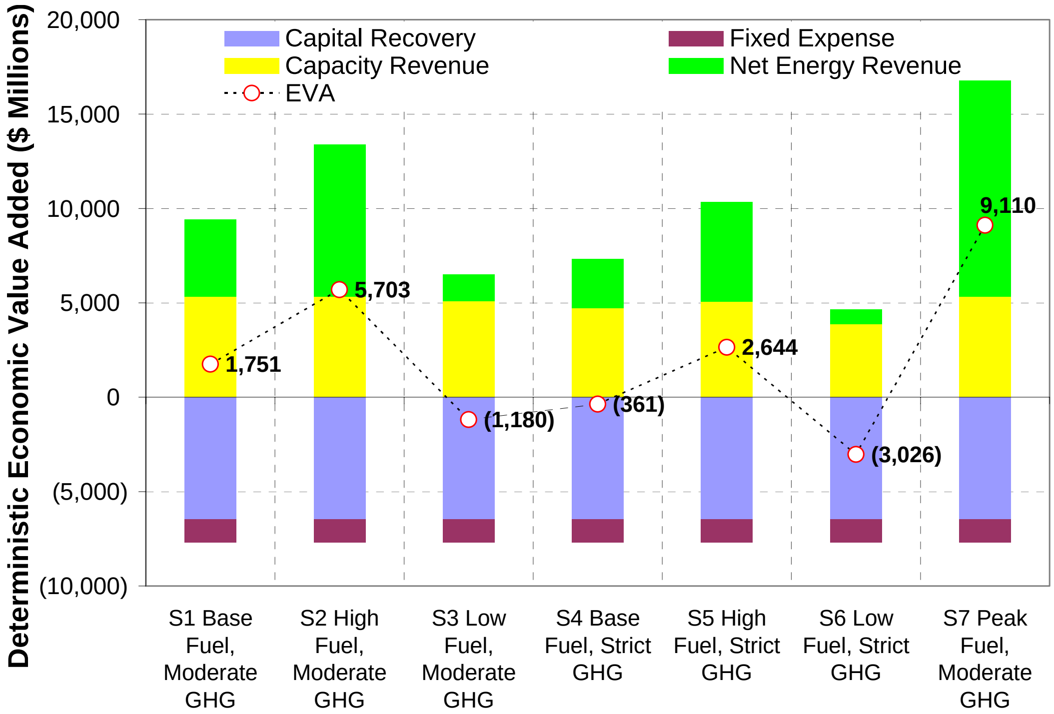


Figure 44. Deterministic EVA by Component – Authority Ownership

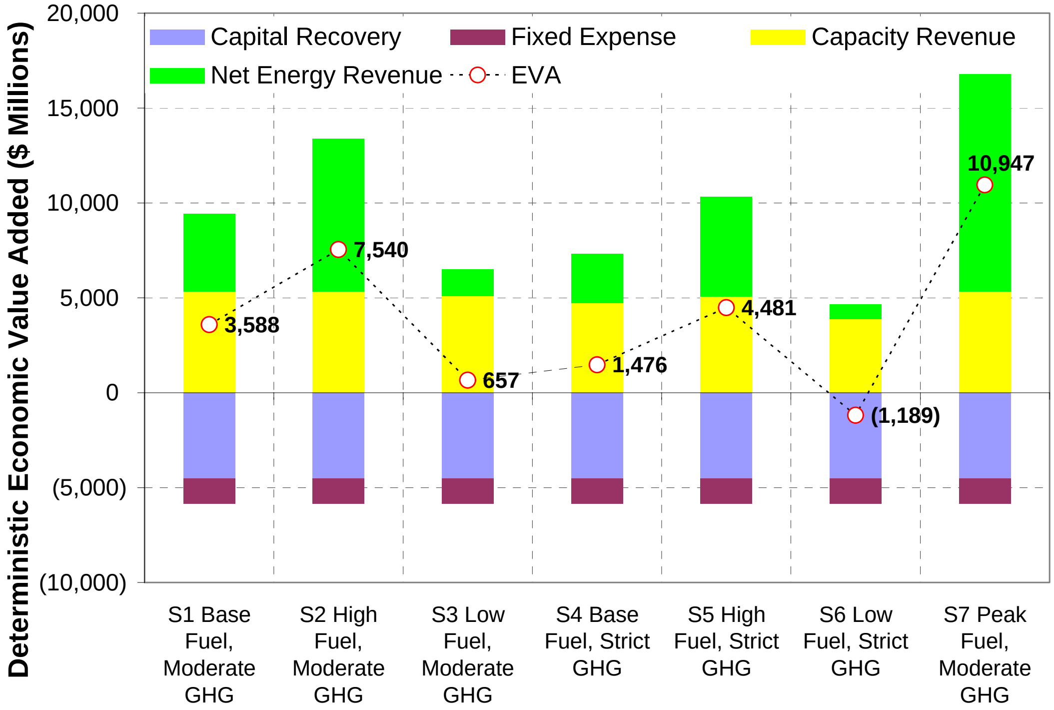


Figure 45. Deterministic EVA – IOU Ownership

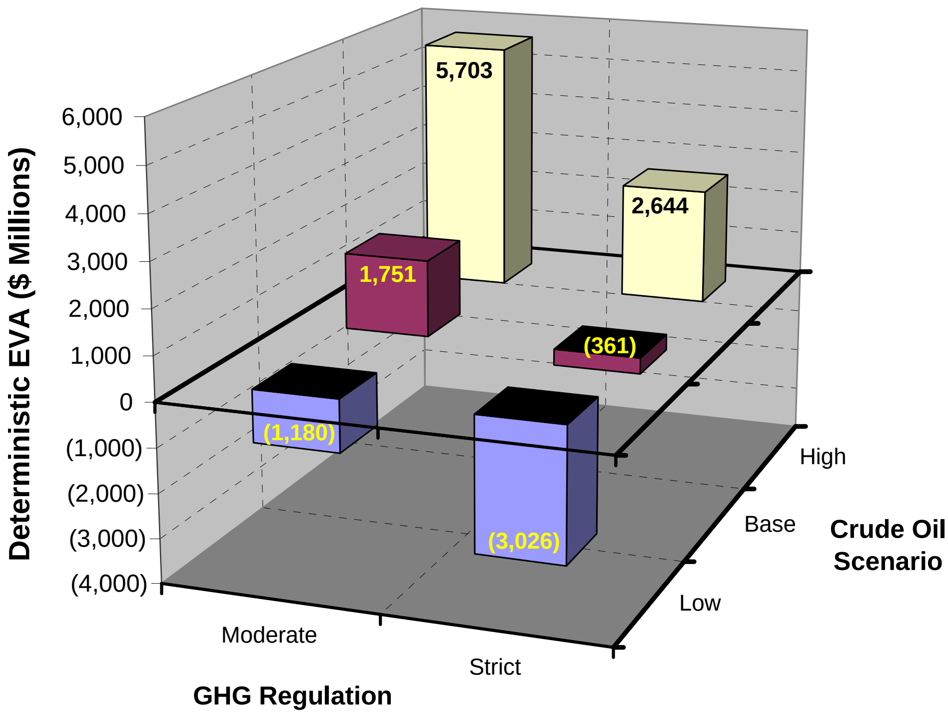
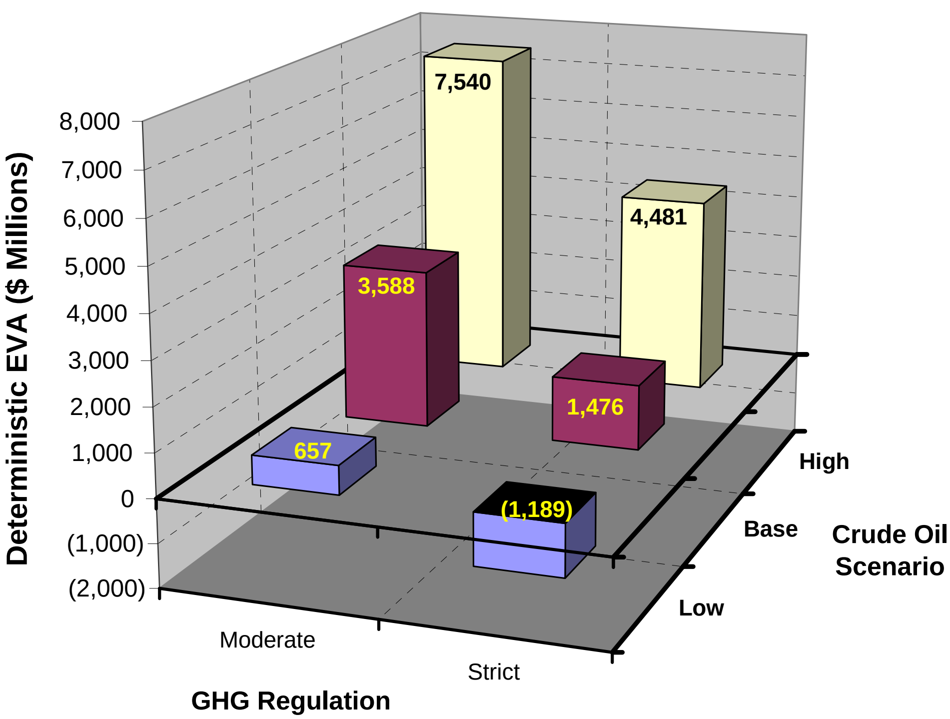


Figure 46. Deterministic EVA – Authority Ownership



7.2 Scenario Conditional Monte Carlo Simulation Results

As described in Section 6.2, uncertainty in primary market variables (fuel prices and GHG policy) affecting energy prices has been addressed through the modeling of several discrete scenarios. In this section, we present results when the uncertainties of the secondary variables are tested through Monte Carlo simulation, conditioned on keeping the values for the primary market variables fixed for each scenario. We have simultaneously performed simulations of each scenario, creating a set of conditional results – that is, distributions of annual net benefit and EVA that are conditional on a fixed set of market variables. While these simulations are primarily intended as an interim step toward the integrated simulation of all variables, they provide useful insight into the effects of the secondary variables, which include capacity market parameters, levels of future CapEx, transaction costs, transition and G&A costs, and major forced outage events.

7.2.1 Annual Net Benefits

The effect of uncertainty in the secondary variables on the annual net benefits of S1 under IOU ownership is summarized in Figure 47. The conditional expected value line is slightly lower than the deterministic line, which is repeated here from Figure 38. This is because some of the simulated input variables do not have symmetric distributions, relative to the deterministic default values. The spread of results around the conditional expected value and the relationship to the deterministic benefit series is similar for each of the other six scenarios.

The effect of uncertainty in the secondary variables on the annual net benefits of S1 under Authority ownership is summarized in Figure 48. For reference, the deterministic annual net benefit series from Figure 39 is shown, as well. The conditional expected value net annual benefits are somewhat lower than the deterministic annual net benefits due to the asymmetric distributions of variables such as prospective CapEx, outages, and cost of capital. The spread of results around the expected value is similar for each of the other six scenarios.

Conditional expected annual net benefits for IOU ownership are shown for the seven primary variable scenarios in Figure 49. Note that these conditional expected values are very similar to, but slightly lower than, the deterministic annual net benefits shown in Figure 40. Conditional expected annual net benefits for Authority ownership are shown for the seven primary variable scenarios in Figure 50. Note that these conditional expected values are similar to, but lower than, the deterministic values shown in Figure 41.

Figure 47. Conditional Annual Net Benefits –S1, IOU Ownership

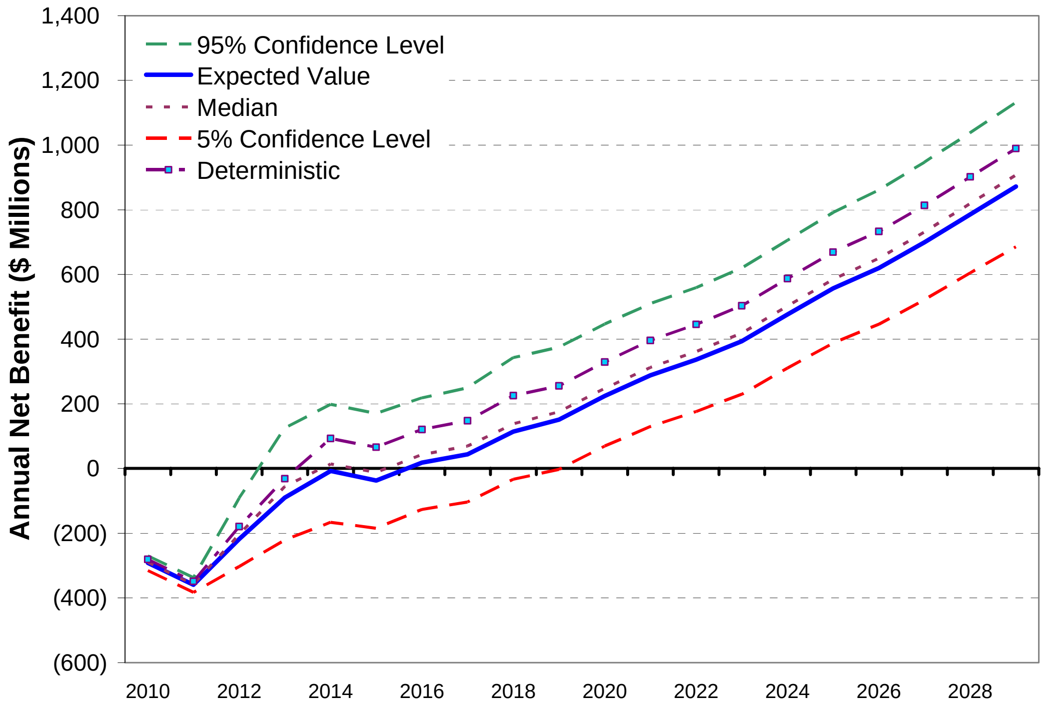


Figure 48. Conditional Annual Net Benefits –S1, Authority Ownership

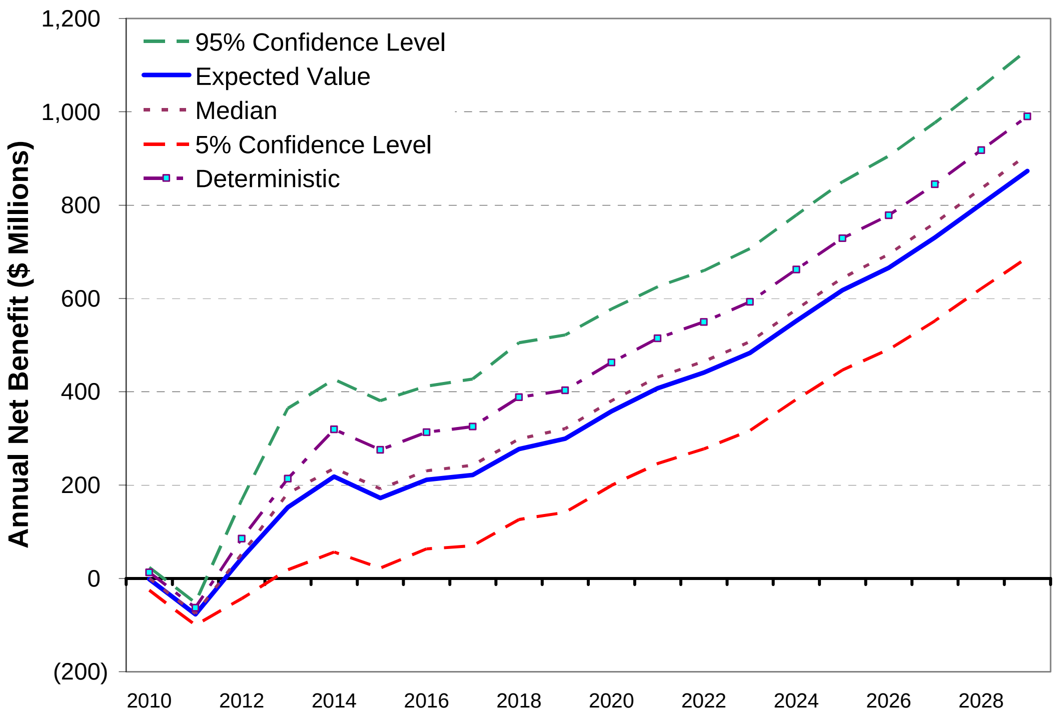


Figure 49. Conditional Expected Annual Net Benefits – IOU Ownership

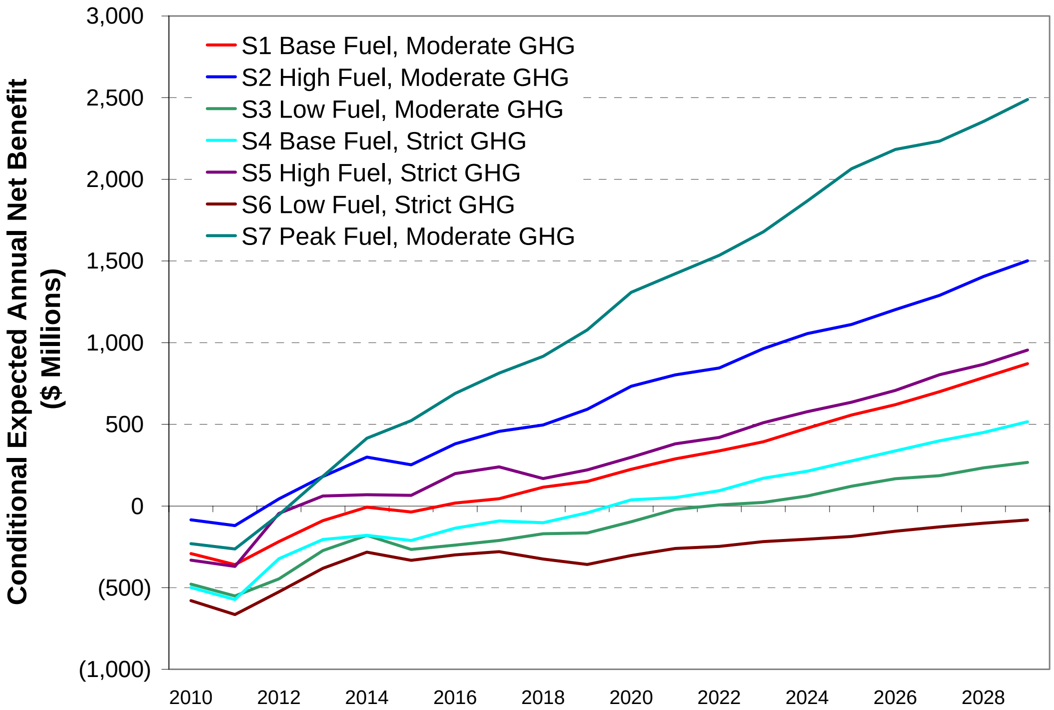
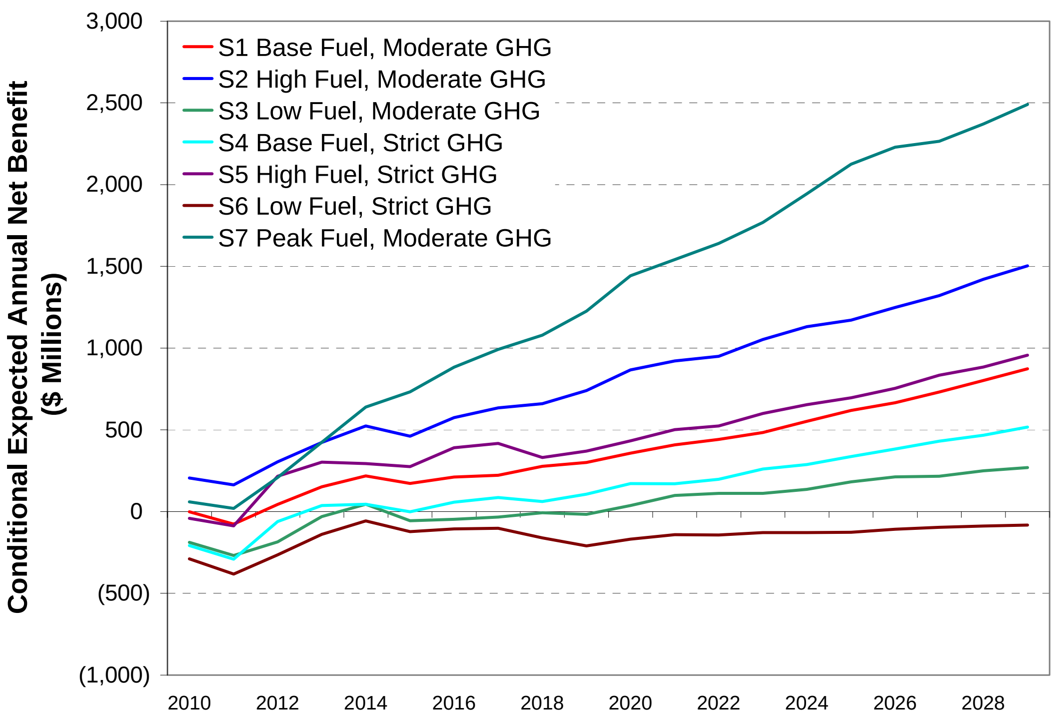


Figure 50. Conditional Expected Annual Net Benefits – Authority Ownership



7.2.2 <u>Economic Value Added</u>

Components of the conditional expected EVA for each of the primary variable scenarios are shown in Figure 51 for IOU ownership and in Figure 52 for Authority ownership. With IOU ownership, S3, S4, and S6 show negative conditional EVA. Only S3 and S6 show negative results with Authority ownership.

The IOU ownership conditional expected EVA results for the six primary scenarios (S1 through S6) are shown in Figure 53. This presentation shows the effects of the primary variables (crude oil price and CO_2 price) on conditional expected EVA. Note that these values are lower than the deterministic EVA results shown in Figure 45 by about $900 million. This risk adjustment is the result of the asymmetric probability distributions assigned to future CapEx, financing costs, and major outages.

Figure 54 shows the same information under Authority ownership. Note that these conditional expected EVAs are lower than the deterministic EVA results shown in Figure 46 by about $900 million as well.

Figure 51. Components of Conditional EVA – IOU Ownership

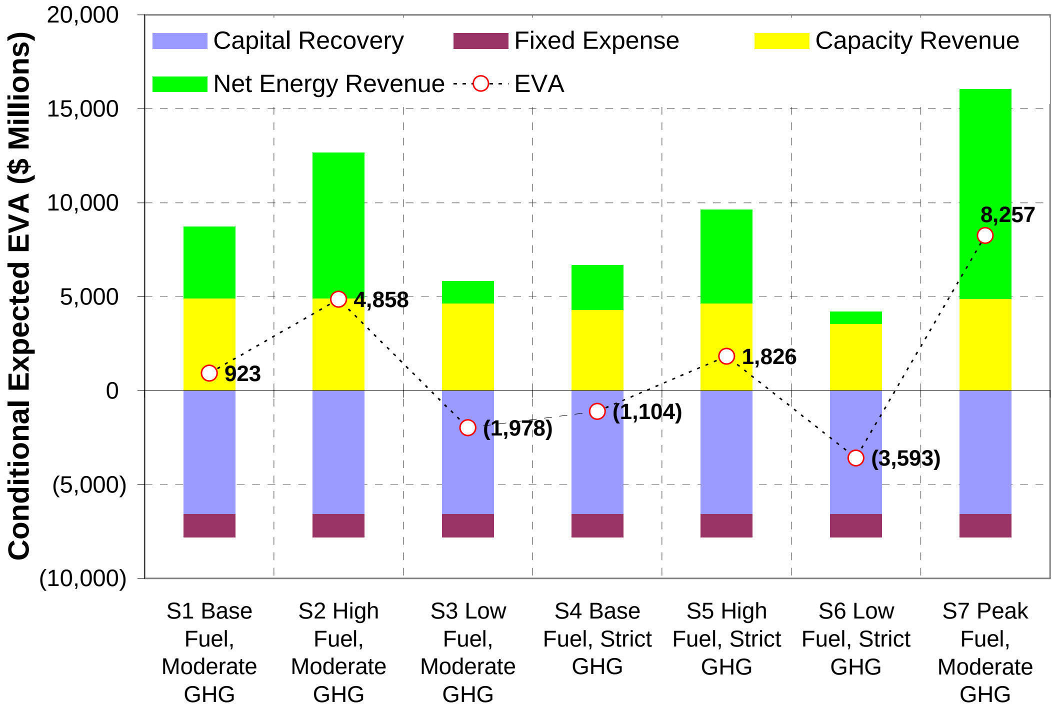


Figure 52. Components of Conditional EVA – Authority Ownership

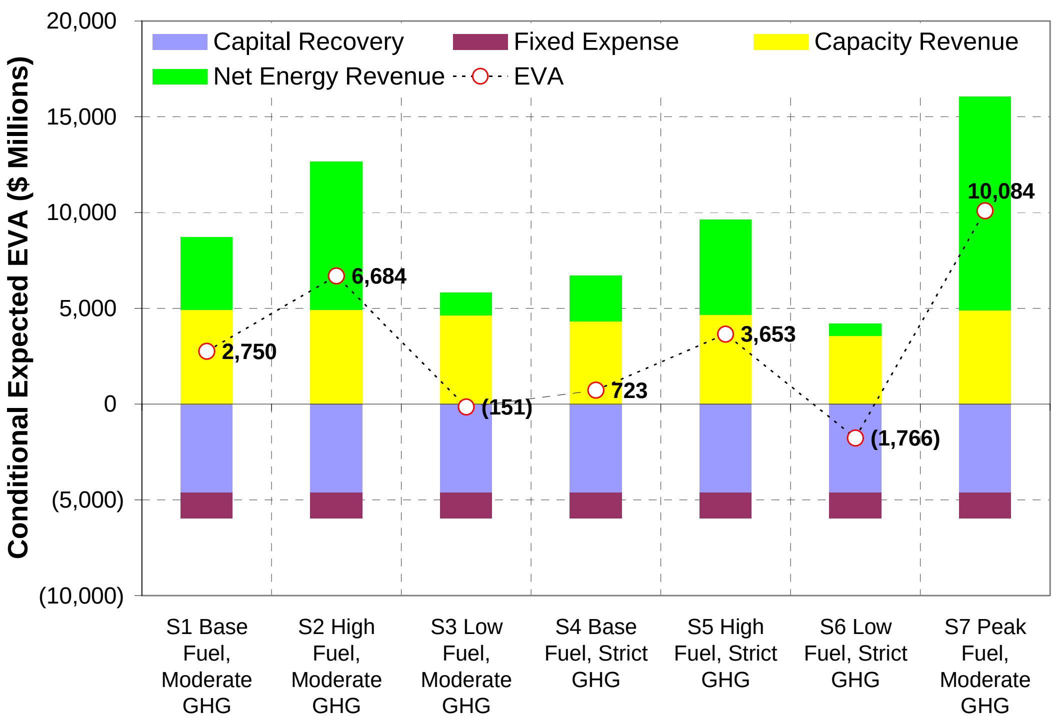


Figure 53. Expected EVA Results by Scenario – IOU Ownership

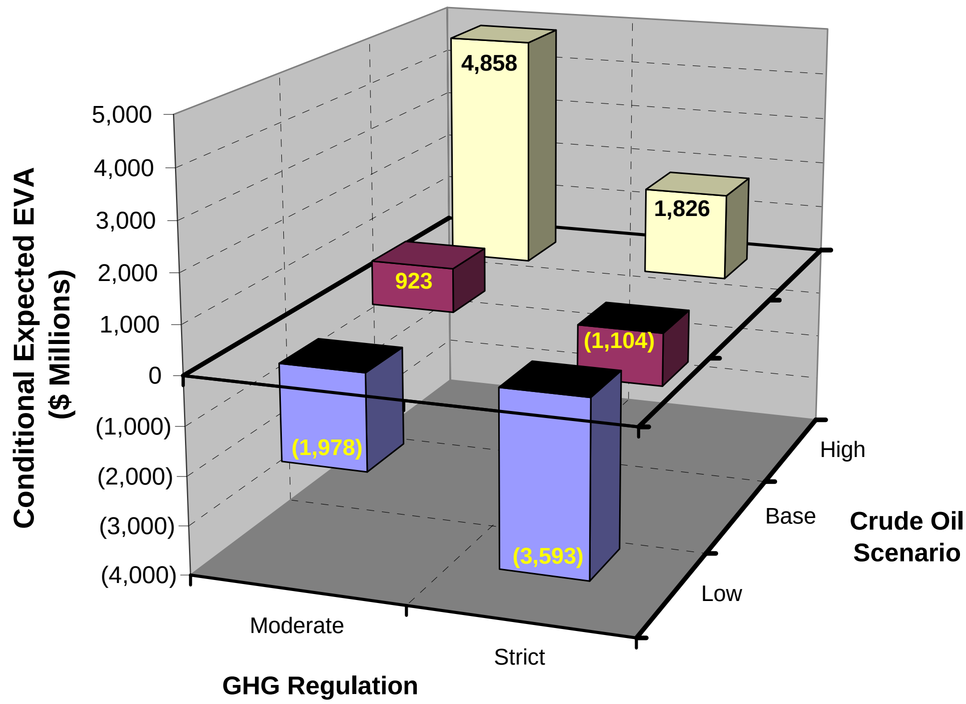
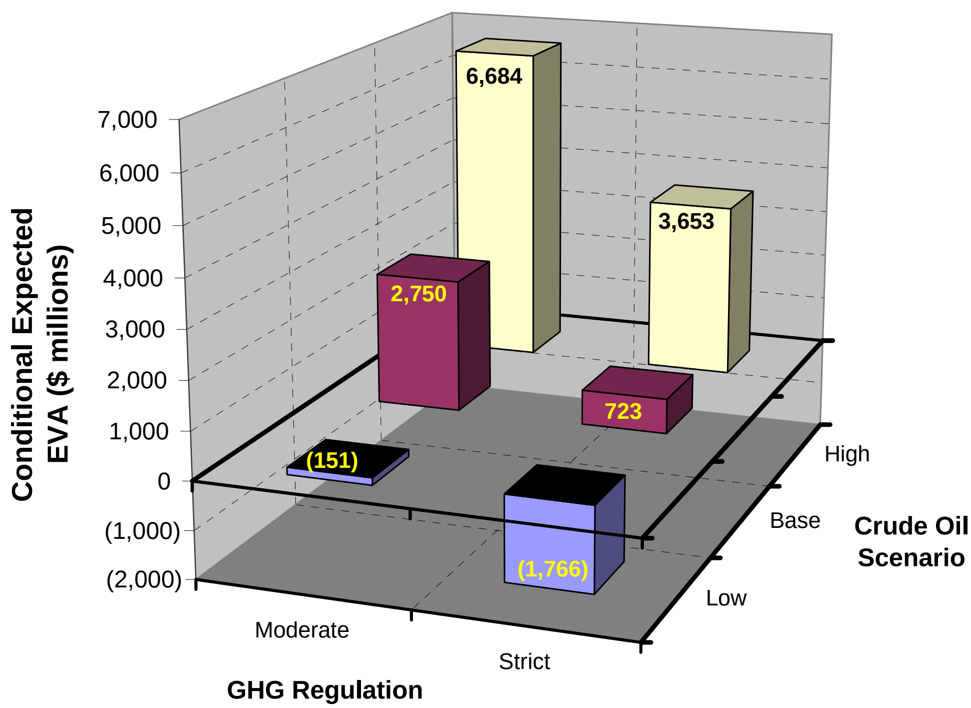


Figure 54. Expected EVA Results by Scenario – Authority Ownership



7.3 Full Monte Carlo Simulation Results

The Monte Carlo random sampling approach to incorporate the primary market variables (fuel prices and GHG policy, as represented by CO_2 price) is described in Section 6.2. The results presented in this section combine Monte Carlo simulation of both the primary and secondary uncertainty variables.

7.3.1 Annual Net Benefits

The range of annual net benefits under IOU ownership for full simulation is shown in Figure 55. The same results for Authority ownership are shown in Figure 56. The expected value remains negative for IOU ownership for eight years, but it is negative for only three years under Authority ownership. On the other hand, there is still a 5% chance of negative annual benefits under IOU ownership for 17 years and Authority ownership for 16 years.

Components of the annual net benefits are shown in Figure 57 and Figure 58 for the two ownership cases. Expected annual net benefits for the two ownership cases are compared in Figure 59.

Figure 55. Range of Annual Net Benefits – IOU Ownership

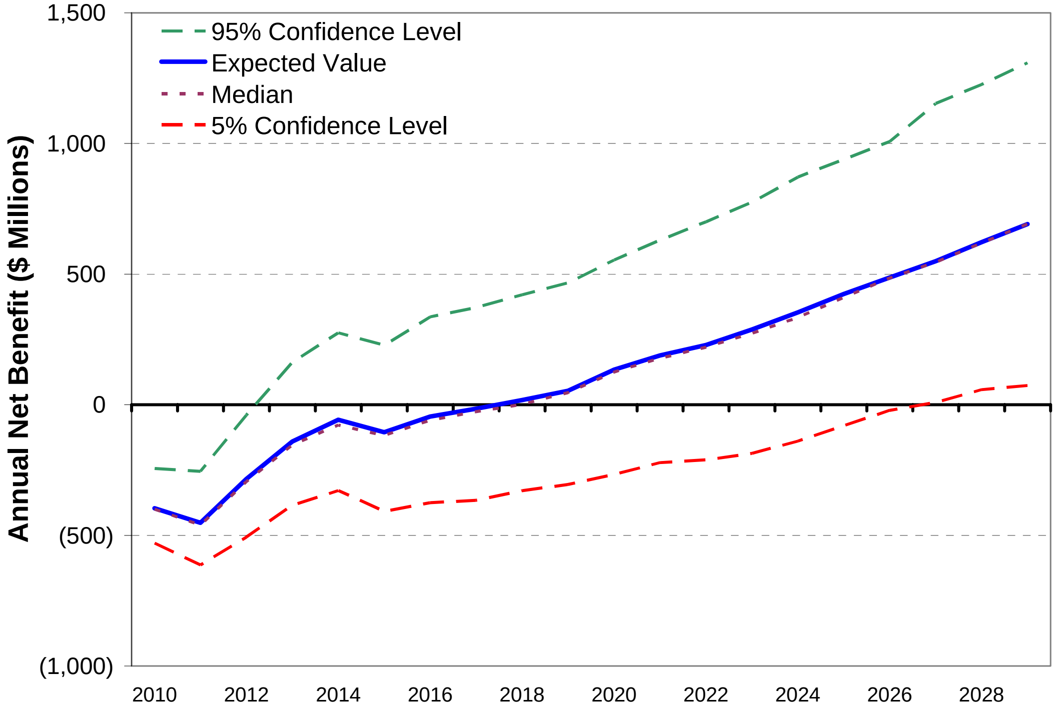


Figure 56. Range of Annual Net Benefits – Authority Ownership

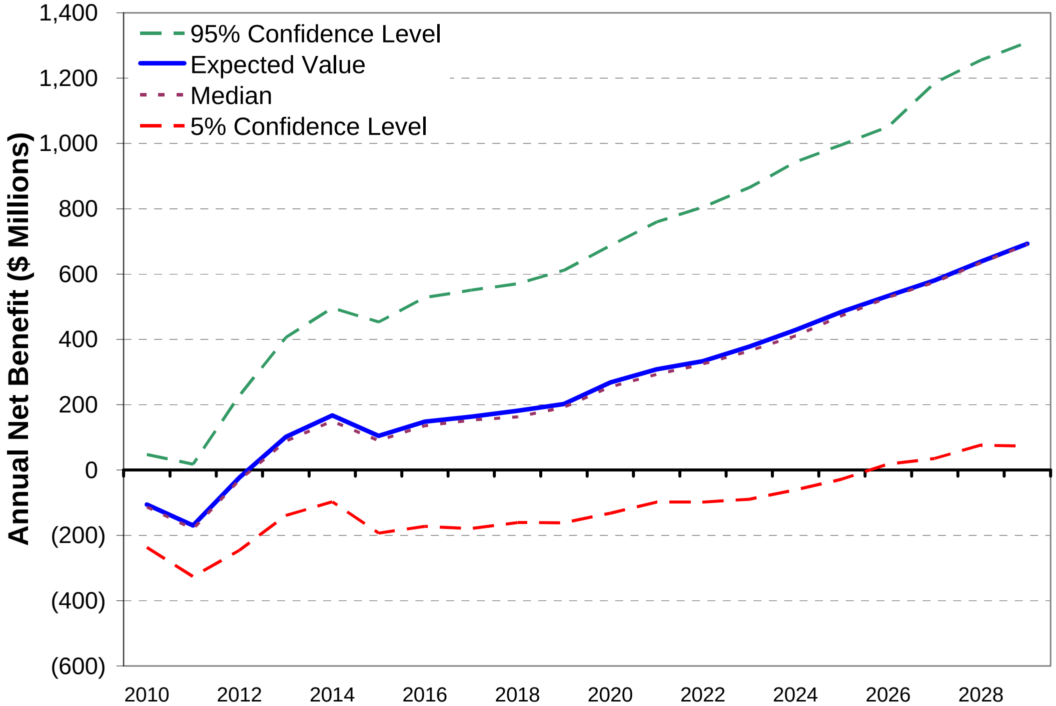


Figure 57. Components of Annual Net Benefits – IOU Ownership

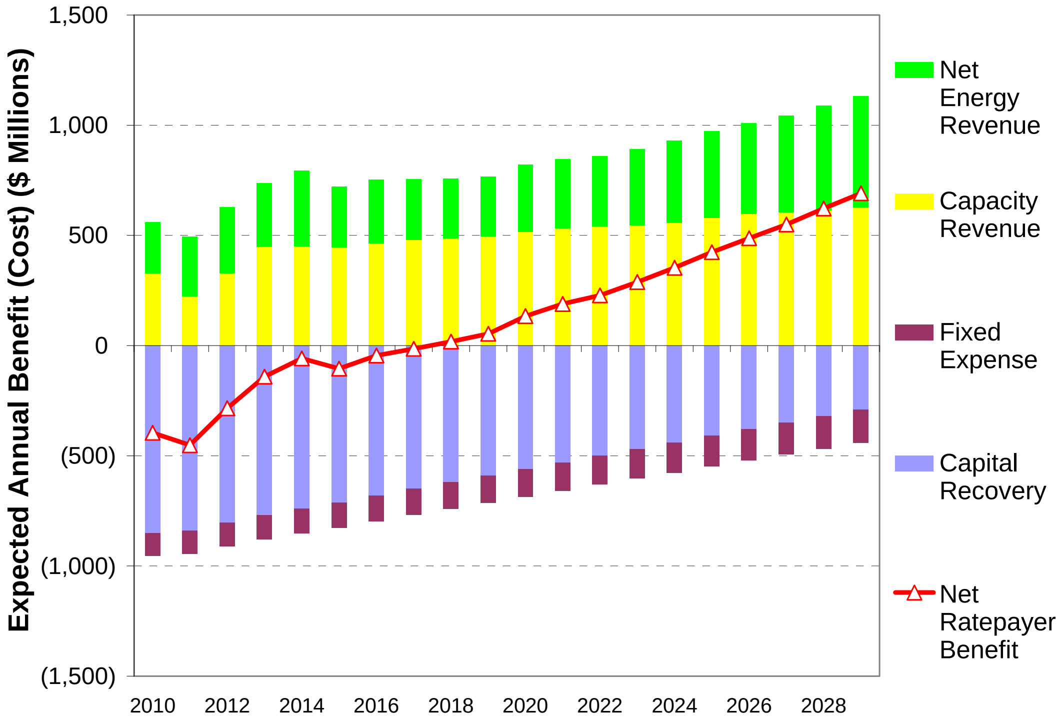


Figure 58. Components of Annual Net Benefits – Authority Ownership

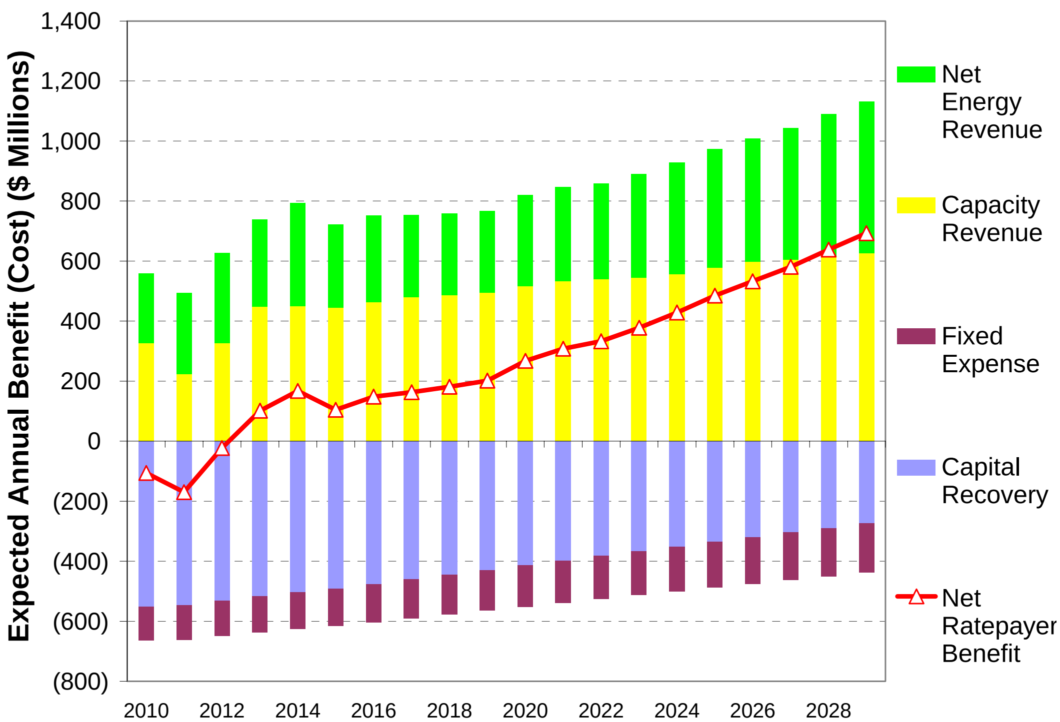
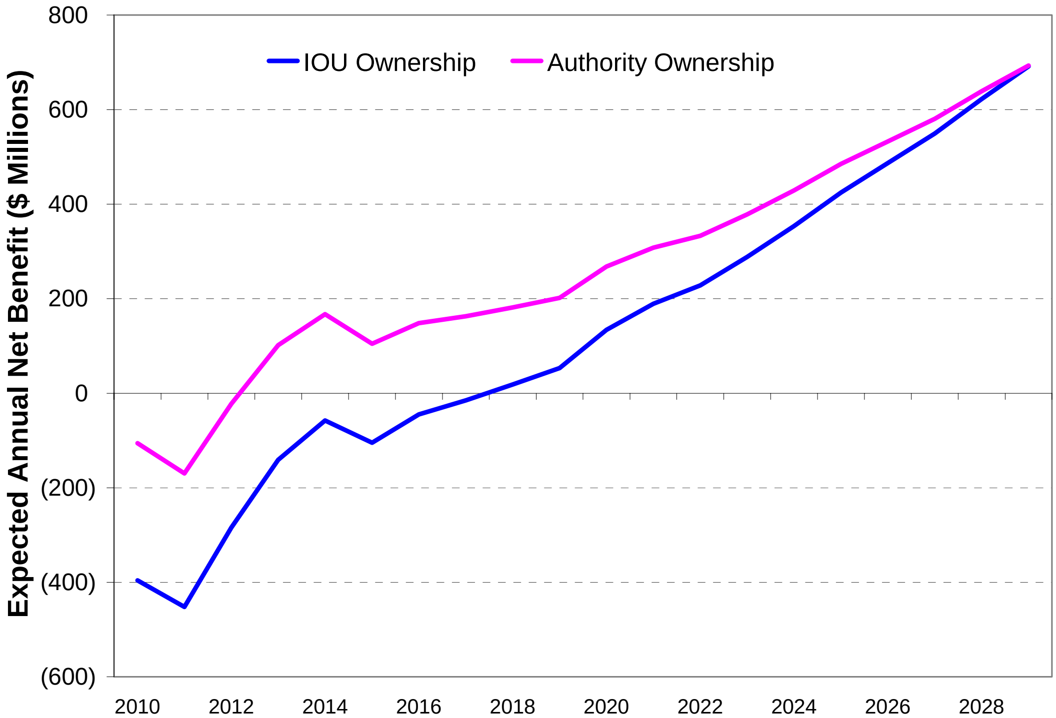


Figure 59. Comparison of Expected Annual Net Benefit



7.3.2 Economic Value Added

The conditional EVA distribution values (expected value, and the 5% and 95% confidence values) for each of the primary variable scenarios (S1 through S7) and for the full Monte Carlo simulation are compared in Figure 60 for IOU ownership. The same distribution values are shown for Authority ownership in Figure 61. Note that the 5% to 95% confidence range for the full Monte Carlo simulation on the right-hand side of the chart is significantly narrower than the combined ranges of S1 through S6. This is because S1 through S6 use Low, Base and High deterministic oil price forecasts, whereas the Full Simulation case uses independent (uncorrelated) probability distributions for fuel prices and GHG policy.[68] Random draws taken from the independent fuel price and GHG policy distributions results in EVA outcomes that are more centrally distributed than for the range of conditional scenarios.

Components of full simulation EVA are compared side-by-side for the ownership cases in Figure 62. The expected EVA for IOU ownership is virtually zero, *i.e.*, negative $3 million. The expected EVA for Authority ownership is a substantial positive $1.824 billion. On an expected value basis, the primary difference between these two ownership structures is the cost of capital. Hence, the large difference stated on a risk-adjusted basis between the IOU ownership outcome

[68] The Monte Carlo simulation of oil prices is performed as a chronological sequence with reversion back towards the expected price after random shocks move prices above or below the expected price. Unlike the deterministic Low, Base, and High oil price cases, the randomly simulated oil price paths do not stay at a single probability level across the 20 years. This averaging effect of random deviations makes it very unlikely that any single path will follow an extreme scenario for the entire study period.

of about zero versus the Authority outcome of $1.824 billion is almost entirely attributable to the advantageous debt cost rate for 100% of the Authority's capital requirement compared to the higher debt and equity cost for an IOU.

Figure 60. EVA Distribution – IOU Ownership

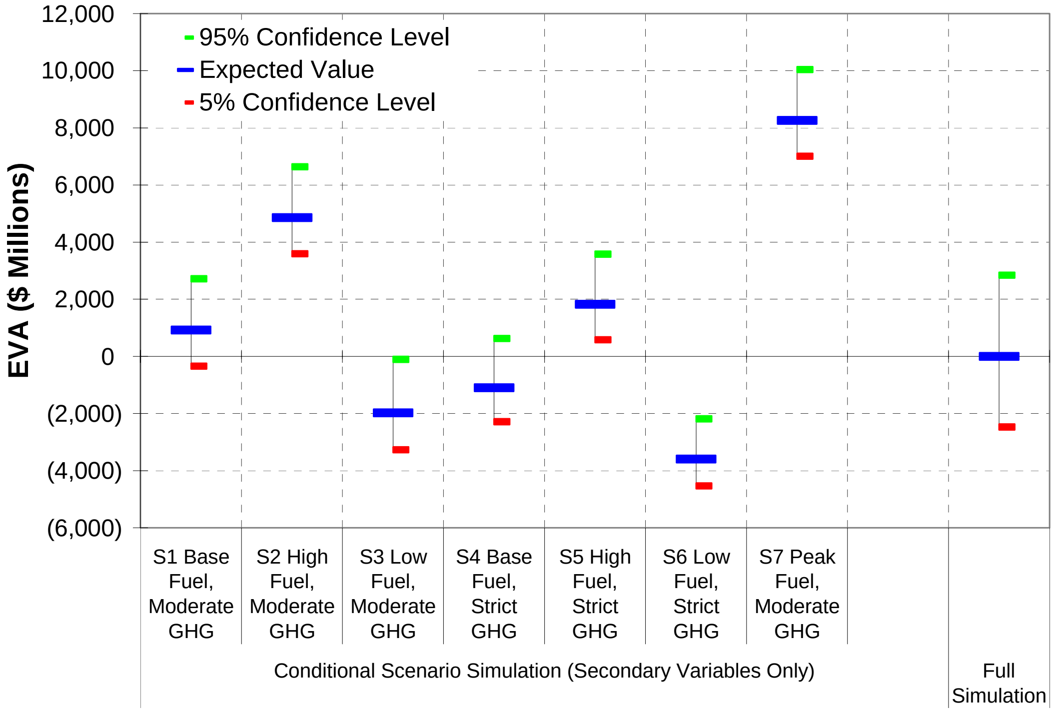


Figure 61. EVA Distribution – Authority Ownership

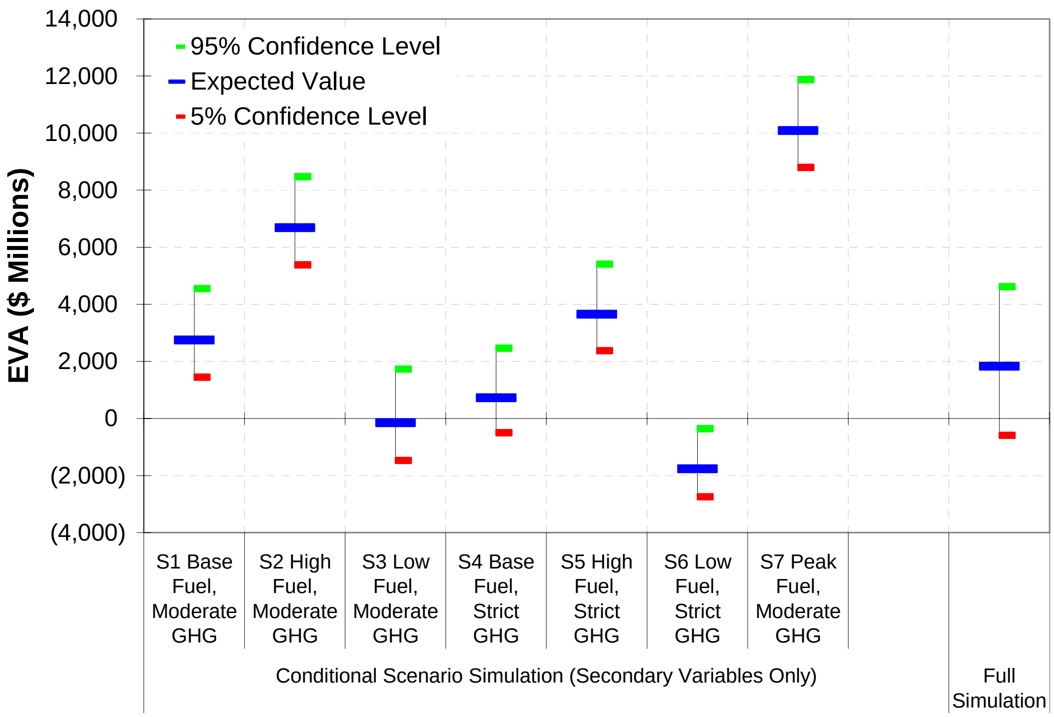
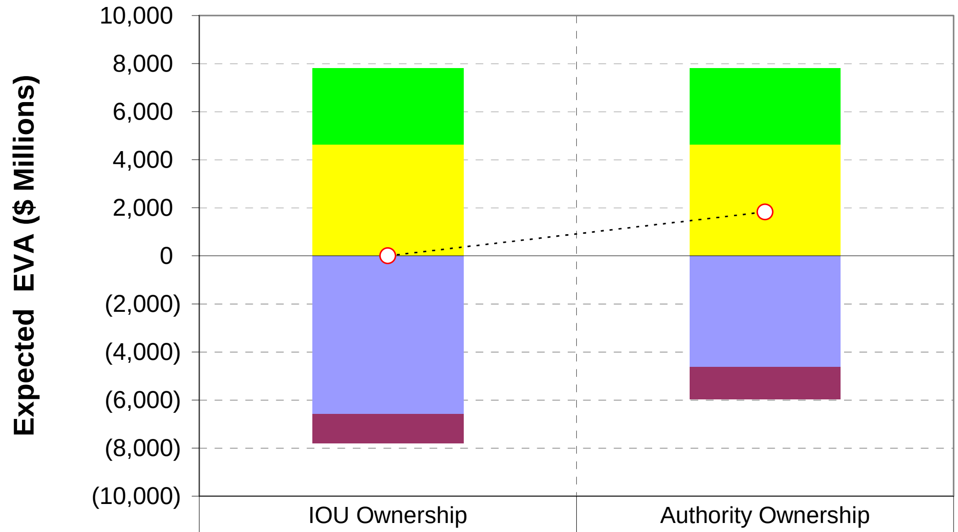


Figure 62. Components of EVA – IOU and Authority Ownership

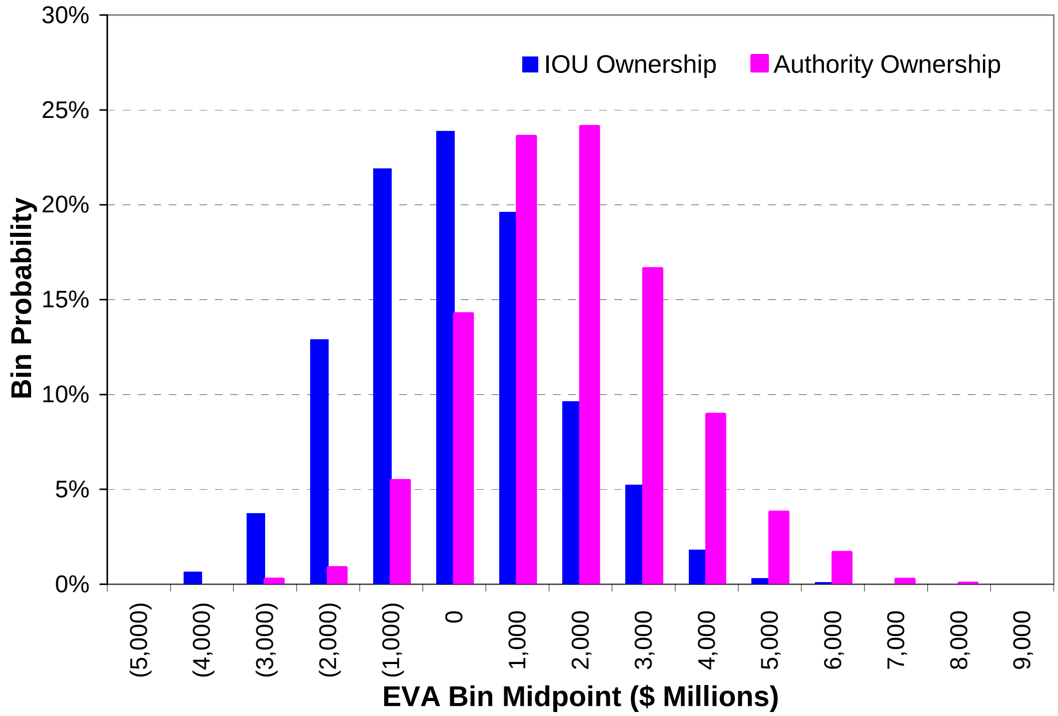


	IOU Ownership	Authority Ownership
Net Energy Revenue	3,178	3,178
Capacity Revenue	4,618	4,618
Fixed Expense	(1,219)	(1,339)
Capital Recovery	(6,580)	(4,632)
EVA	(3)	1,824

7.3.3 <u>Measures of Risk</u>

The shape of the uncertainty distribution for the present value of EVA for both IOU and Authority ownership is shown in Figure 63. The histogram in Figure 63 is based on “bins” of $1 billion increments on the x-axis, so the results discussed here are rounded to the nearest billion dollars. Several aspects of risk are apparent from this graph. First, both forms of ownership result in a wide range of possible outcomes, from large positive EVA to large negative EVA. Second, each form of ownership is roughly symmetric in its shape. The IOU ownership distribution has a most likely value of zero EVA, with a downside tail extending to negative $4 billion, and an upside tail extending to positive $6 billion. The Authority ownership distribution has a most likely value of $2 billion. Its downside tail extends to negative $3 billion, while its upside tail extends to $8 billion.

Figure 63. Histogram of EVA Distribution by Ownership



The same EVA probability distributions are compared in cumulative form in Figure 64 in order to visualize whether there is a risk-reward tradeoff between the two forms of ownership. The EVA cumulative probability distribution curves for the two forms of ownership have similar shapes, but do not cross each other. The EVA cumulative probability distribution curve under Authority ownership is decidedly to the right of the IOU ownership distribution, by about $1.8 billion over the entire probability range, as shown for the 5% and 95% probability levels as well as for the expected EVA. At all probability levels, Authority ownership provides a superior outcome relative to IOU ownership – *i.e.*, their cumulative probability curves do not cross. This implies that there is no risk-reward disadvantage from choosing Authority ownership over IOU ownership.

Figure 64. Cumulative Probability Distribution of EVA

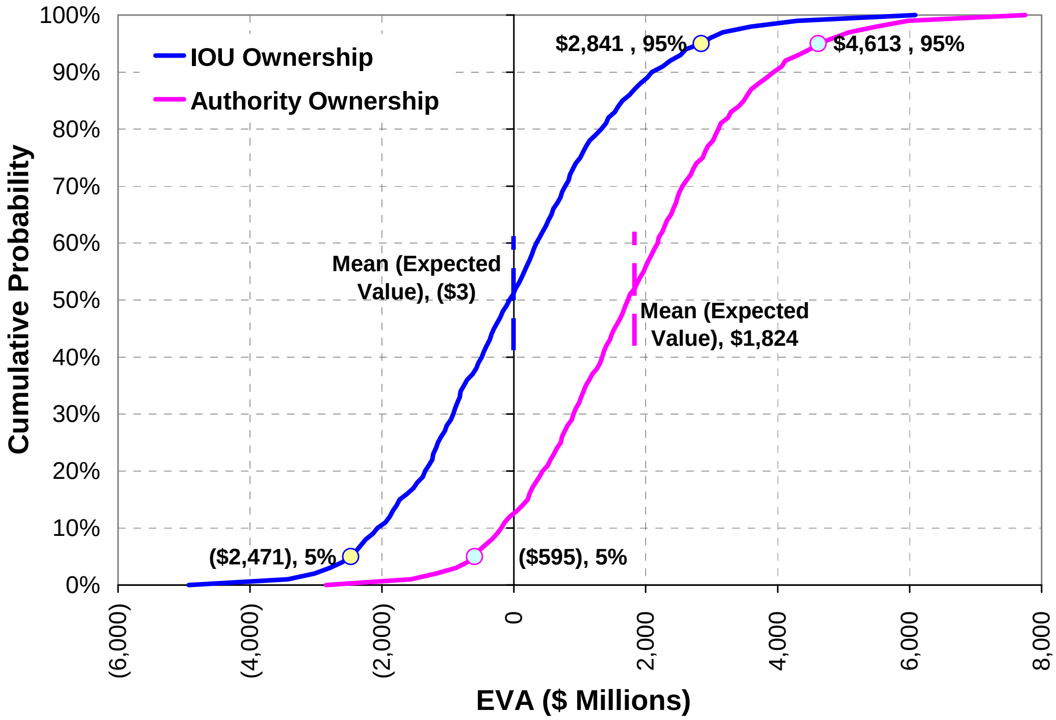


Figure 65 and Figure 66 show additional summary statistics of the probability distribution under each form of ownership. While IOU ownership has about a 50% chance of negative EVA, the exposure to losses under Authority ownership is far less, about 13%. Also, the median (50% probability) value for each distribution is very close to its mean, indicating a nearly symmetrical distribution. These figures also show the calculated conditional means for all losses and for losses in the lowest 5% of each EVA distribution. The conditional means are used to compute the expected loss and TVaR95 risk measures, shown in Figure 67 and Figure 68.

Figure 65. Statistics of EVA Distribution – IOU Ownership

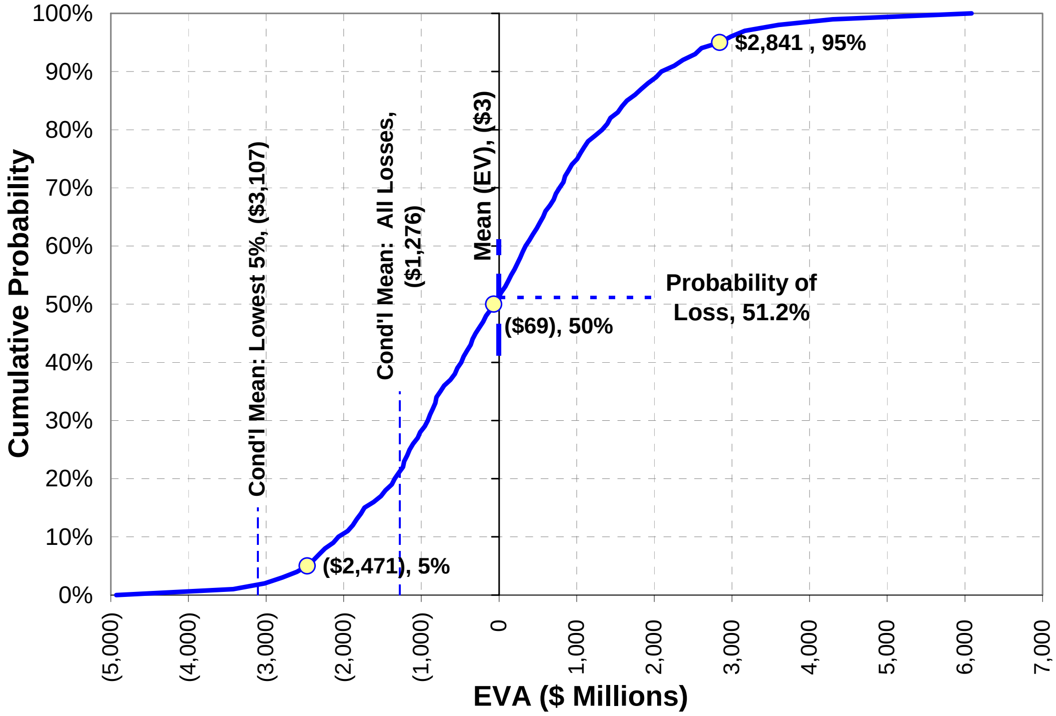
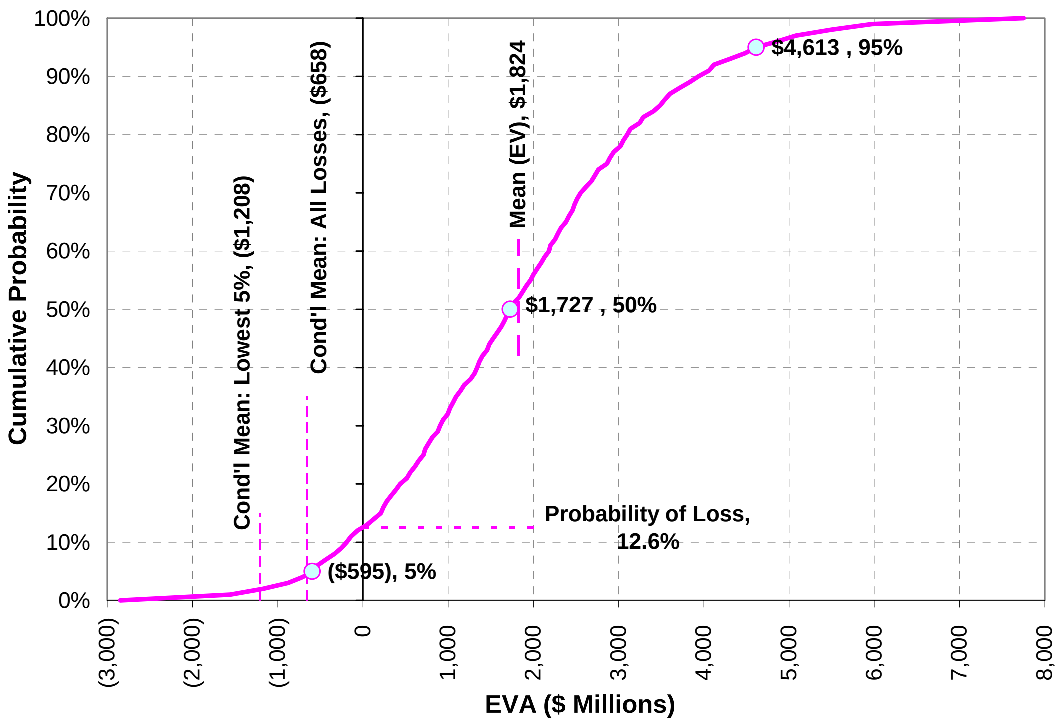


Figure 66. Statistics of EVA Distribution – Authority Ownership



To understand the risks of unfavorable outcomes in the two distributions, it is helpful to focus on the lower left portion of Figure 65 and Figure 66. Figure 67 and Figure 68 zoom in on the EVA loss portion of the IOU and Authority ownership EVA distributions, respectively, and show three key risk metrics – probability of loss, the expected loss value, and TVaR95 – all measured from the zero EVA risk threshold. These key risk metrics have been formulated in order to address in a consistent and rigorous form either the IOU's or the Authority's downside risk exposure under rate base regulation. Probability of loss only measures the likelihood of a loss of any size. Probability of loss is paired with the expected loss, which is the mean (average) loss of all outcomes that result in a negative EVA. TVaR95 is the expected (mean) loss conditional on the outcome being worse than the 5% probability level.

IOU ownership has a loss probability of about 51% and an associated expected loss of about $1.3 billion, compared to a loss probability of about 13% and an expected loss of about $0.7 billion for Authority ownership. In other words, the likelihood of loss is four times as large for IOU ownership, and whenever a loss occurs, its average size is twice as large as for Authority ownership.

Also of interest from a risk standpoint are the TVaR95 values, which measure losses for the worst 5% of outcomes. IOU ownership would result in a TVaR95 of about $3.1 billion, compared to $1.2 billion for Authority ownership, a difference of $1.9 billion.

Figure 67. EVA Downside Risk Measures – IOU Ownership

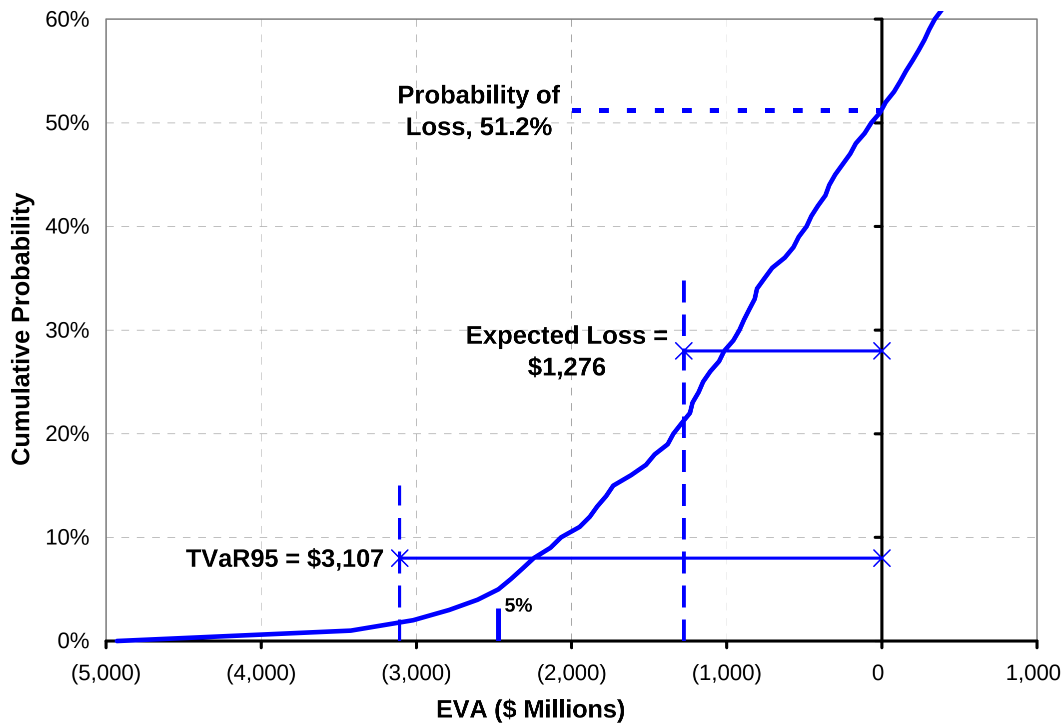
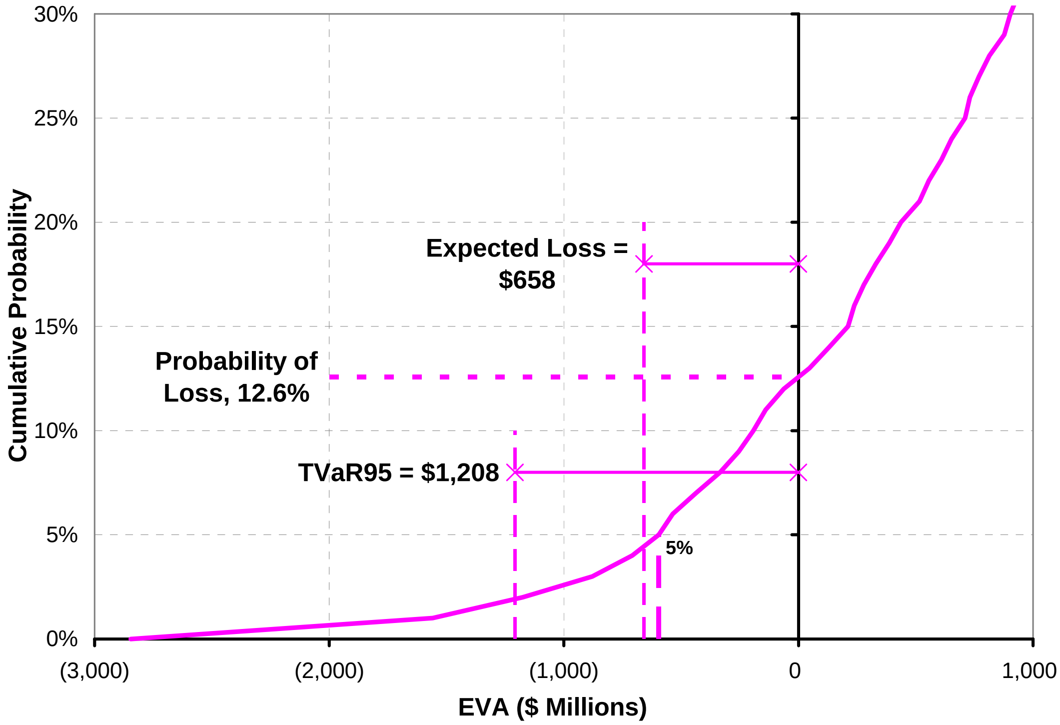


Figure 68. EVA Downside Risk Measures – Authority Ownership



The risk metrics and other statistics from the previous five figures are summarized in Table 21 along with two conventional risk measures – standard deviation and VaR. From the expected values, it is clear that, while Authority ownership is likely to provide a significant benefit to ratepayers, IOU ownership is expected to provide no better than a break-even net benefit. Both forms of ownership are subject to about the same level of uncertainty around their expected value, as measured by standard deviation and by the downside risk measures that use expected value as the risk threshold. Much more meaningful are the risk measures that start from a $0 EVA, which were shown in Figure 67 and Figure 68.

Table 21. EVA Distribution Statistics
($ Millions)

		IOU Ownership	Authority Ownership
	Distribution Measures		
a	Expected Value (mean)	(3)	1,824
b	Median (50th percentile)	(69)	1,727
c	5th percentile	(2,471)	(595)
d	95th percentile	2,841	4,613
e	Conditional mean of lowest 5% of values	(3,107)	(1,208)
f	Conditional mean of all negative values	(1,276)	(658)
g	Conditional mean of all values up to EV	(1.276)	584
	Risk Measures		
h	Standard Deviation	1,824	1,612
	Measures Relative to EV(mean):		
i	VaR-95% (a – c)	2,469	2,420
j	Tail VaR-95% (a – e)	3,105	3,033
k	Expected Loss (a – g)	1,274	1,240
	Measures Relative to Zero EVA:		
l	VaR-95% (– c)	2,471	595
m	Tail VaR-95% (– e)	3,107	1,208
n	Expected Loss (– f)	1,276	658
o	Probability of Loss	51.2%	12.6%

8 OTHER RISK FACTORS

8.1 Impact of Rate Base Regulation on Wholesale Markets

8.1.1 Overview

In this section, LAI examines the factors that may affect the competitiveness of the PJM wholesale market if the Mirant assets in Maryland are returned to rate base regulation. In analyzing this question, we emphasize the impact rate base regulation will likely have on the ability of energy and capacity markets to function properly and whether the return to rate base regulation will distort energy and/or capacity price signals, thereby undermining wholesale market efficiency objectives. In Section 8.2, LAI addresses the impact of the re-regulation initiative on retail markets in Maryland.

PJM market rules allow all generation resources to participate in the wholesale power markets regardless of whether a generation resource operates under a PPA, operates as a merchant generator, or is owned and operated by an IOU under traditional cost-of-service regulation. The wholesale power markets administered by PJM are subject to FERC regulation. Under the FERC-approved Open Access Transmission Tariff, PJM has a number of market safeguards to ensure that generators cannot exercise undue market power when demand is constrained.[69] The existing PJM settlement mechanism governing energy scheduled in the day-ahead market (DAM) and the real-time market (RTM) ensures that merchant and regulated generators alike receive identical energy revenues in every hour at every location.[70]

8.1.2 PJM Wholesale Market Regulations

Prior to May 2008, certain PJM generators were exempt from price mitigation and were permitted to include a premium above the marginal cost of producing energy – *i.e.*, a bid adder – when scheduling generation in the DAM or the RTM. The inclusion of a bid adder enhances profitability from energy sales when a generator's bid is accepted and sets the LMP – the greater the bid adder, the higher the profit. Importantly, a generator that is tempted to increase the size of the bid adder runs the risk of not clearing in the DAM or the RTM, thereby losing the opportunity to participate in otherwise profitable energy sales. The inclusion of a bid adder relative to the cost of producing energy would normally trigger market safeguards administered by PJM's Market Monitoring Unit (MMU) under the three-pivotal-supplier test designed to ensure that generators cannot extract economic rents except under defined "scarcity" conditions.

Over the years, PJM and FERC have struggled with the need for exemptions from the mitigation rules for newly constructed generation and for transactions across large interconnections.[71] In early 2008, the Commission filed a Section 206 complaint under the Federal Power Act, asking

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[69] Under PJM's FERC-approved market power screen, the "three-pivotal-supplier" test imposes bid capping when there are three or less suppliers available for redispatch that are all pivotal to ensure bulk power security. The generation units whose owner is jointly pivotal are subject to mitigation when combined with the two largest other suppliers.

[70] LMPs across PJM can vary due to congestion and transmission losses.

[71] *Maryland Pub. Serv. Comm'n v. PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,340 (2008) at P 3.

FERC to remove the exemptions from energy offer mitigation. In May 2008, FERC granted the Commission's complaint and eliminated the exemptions, and upheld its decision in an Order on Rehearing issued December 19, 2008. FERC's determination to remove the exemptions "was not based on a mark-up analysis or a factual finding that any particular generator had exercised market power."[72] Instead, FERC reasoned that the standard for exemption was imprecise, thereby warranting the application of the same standard that applies to all generators, including previously exempt generators.

Under traditional cost-of-service regulation or a fully competitive market, generators do not have a financial incentive to include bid adders and would be more likely to offer energy at a price equal to the total marginal cost of producing energy. This cost includes fuel costs, start-up and shut-down costs, non-fuel variable O&M expense, and the unitized cost of emission allowances. Hence, under the return to rate base regulation, LAI assumes that either the IOU or an Authority would bid energy from the existing Mirant fleet at the marginal cost of production. Before FERC issued its May 2008 Order, rate base ownership would have materially lowered LMPs in SWMAAC compared to merchant generation ownership. LAI believes that even after the exemption has been removed, some bid adders may still exist (*e.g.*, generators may continue to make offers up to 10% above their marginal costs without mitigation) that would probably be eliminated under cost-of-service regulation. However, we also believe any drop in LMPs would be relatively small.

Under the merchant generation ownership scheme, significant bid adders are permitted under scarcity conditions or when the resources are not mitigated because they pass the three-pivotal-supplier test. FERC's decision to eliminate the interface and construction exemptions of relevance balances the commercial interests of buyers and sellers in Maryland. FERC's revocation of the exemption reasonably safeguards against seller-specific market power abuse when no real scarcity conditions exist. The December 2008 Order on Rehearing underscores FERC's support of the MMU's oversight of pricing behavior in SWMAAC, in particular, and in PJM, at large, to ensure that prices do not exceed competitive levels by more than 10%. A recent FERC decision also affirmed the reasonableness of the PJM three-pivotal-supplier test.[73]

8.1.3 Comparative PJM Energy Prices

To gain perspective on the impact that cost-of-service regulation has on energy prices in PJM, we have examined the regulatory and market conditions in Virginia. Dominion Virginia Power (DVP) owns, operates, and has under PPAs 17,463 MW in Virginia, including the 1,596 MW[74] (summer) nuclear power plant at North Anna and the 1,598 MW (summer) nuclear power plant at Surry. The Virginia State Corporation Commission (SCC) has the statutory authority to approve or disapprove DVP's costs, including the return of and on capital. We have compared energy prices in DVP's service territory to Pepco, Appalachian Power (AP), and AEP in Ohio. The zone-specific price duration curves for AP, AEP, Dominion (DOM), and Pepco in 2008

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[72] *Id.* at P 35.

[73] *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,145 (2009).

[74] Capacity reflects DVP's ownership only.

based on the DAM LMP data are depicted in Figure 69. Figure 70 shows the fragment of the price duration curves corresponding to the 250 hours when the LMPs are at the top level.

Figure 69. Price Duration Curve: 2008 All Hours

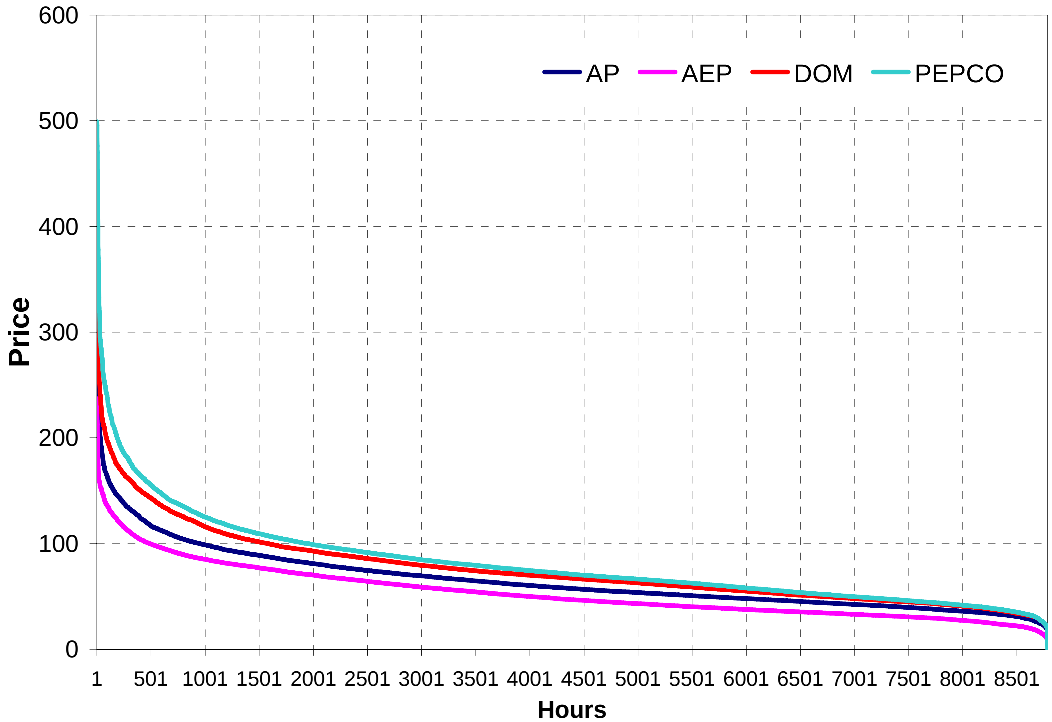
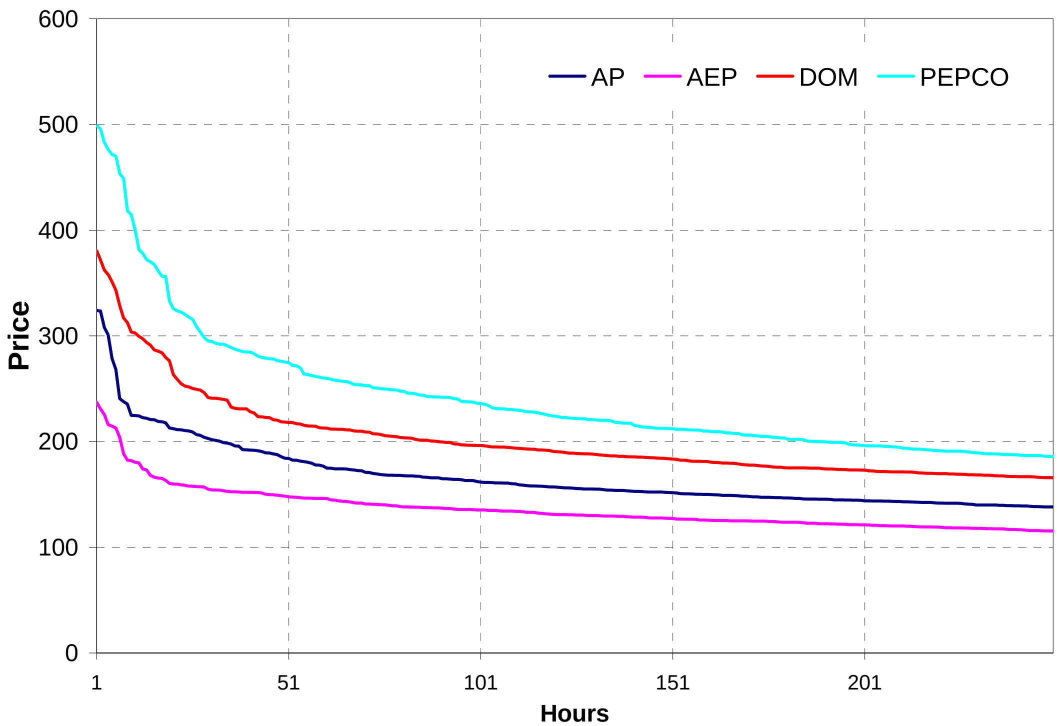


Figure 70. Price Duration Curve: 2008 Top 250 Hours



Based on the price duration curves, we have developed a statistical analysis that helps to better understand how the DAM LMP values differ quantitatively in different load zones at various ranges of the prices.[75] Based on LAI's examination of energy prices in DVP's service territory, we conclude the following.

Most of the year, DVP has higher LMPs than in AP or AEP, but about the same as Pepco. Generators in DVP's zone use more expensive fuel more often compared to AEP, AP, or other PJM generators. LMPs in the DVP and Pepco zones are about equal, except during hours of high demand when Pepco's LMPs are often significantly higher. FERC's decision in 2008 to grant the Commission's complaint, thereby eliminating the exemptions from mitigation, is likely to reduce the LMP differential between DVP and Pepco during hours of highest demand.

The delivered cost of natural gas is the primary determinant of DVP and Pepco LMPs. Variations in DVP and Pepco LMPs during heavy load hours, Monday to Friday, are therefore linked to day-to-day changes in natural gas costs rather than bidder dynamics associated with merchant generation versus cost-of-service ownership.

Through the end of 2008, bid adders during super peak and peak hours, when energy prices are highest, are significantly higher in Pepco relative to DVP. Although the exemption from mitigation of certain units in SWMAAC might have contributed to the price differential during the first half of 2008, there are also noteworthy differences between transmission, DR, and resources in the two zones. LAI believes that the higher bid adders in Pepco's territory are explained by the ability of certain SWMAAC generators to incorporate significant bid adders over the marginal cost of producing energy as allowed under certain market conditions. Moreover, in one or two particularly hot summer days the resource scarcity conditions may have been more severe in SWMAAC than in other adjacent areas, such as DOM, so the price differential between the LDAs was significant. FERC's decision to apply a consistent mitigation provision to all generators should protect against the exercise of undue market power in SWMAAC. The return to rate base regulation in the Pepco LDA would be likely to somewhat reduce LMPs in that zone relative to what would otherwise be the case under the existing ownership regime. However, as we stated before, the reduction of the LMPs would be relatively small. The severity of scarcity is the major price factor in setting LMPs, and it does not depend on the cost recovery mechanism unless all 100% of the LDA zone generators are compensated according to the cost-of-service regulation principles.

8.1.4 Comparative PJM Capacity Prices

Capacity prices set in the first three RPM auctions, especially in SWMAAC and EMAAC, were higher than the RTO because of the transmission constraints and the short lead time that precluded new generation. Capacity prices between the RTO and SWMAAC have since converged, in large part as a consequence of the new backbone transmission upgrades such as TrAIL and a three-year lead time to allow new capacity resources to enter the market. LAI

[75] Table A1 presented in the Appendix illustrates LMPs in the four selected load zones for five ranges of hours: (1) 0-50 hours; (2) 50-100 hours; (3) 100-150 hours, (4) 150-200 hours, and (5) 200-250 hours. Table A2 in the Appendix shows the same values in terms of percent of the corresponding range for DVP.

expects RPM capacity prices in Maryland and Virginia to be about the same in the decade ahead regardless of who owns and operates the existing Mirant fleet. Capacity prices in Maryland will likely be driven by the clearing price in the RTO rather than in SWMAAC once the transmission benefits attributable to TrAIL plus other downstream transmission enhancements are commercialized. This dynamic is prominently featured in LAI's capacity price forecast over the 20-year valuation period and is therefore captured in the derivation of FMV.

8.1.5 New Generation Entry

In order to assess whether a return to rate regulation could impact new entry and ultimately reliability, LAI compared new generation construction in Virginia (which has DVP, a vertically integrated utility) with Maryland (where generation assets were divested) to identify any significant differences in terms of capacity additions. While there has been merchant entry prior to 2002, DVP appears to be adding capacity ahead of its reliability requirements. The enhanced equity return for new investments provided by state legislation helps to support new entry ahead of need. In Maryland, almost no generation has been developed, perhaps deterred by the threat of low energy prices, uncertain capacity prices under RPM, DR, and new backbone transmission projects designed in part to alleviate constraints in SWMAAC. In February 2008, a senior executive of Competitive Power Ventures, LLC, testified before the Maryland Senate Finance Committee that construction required enhanced financial security, in particular, the security of one or more long-term PPA(s). Thus we conclude that on the one hand, guaranteed cost recovery under cost-of-service regulation provides the vertically integrated utilities strong incentive to build. On the other hand, merchant generating companies may not invest in new resources that state regulators and PJM would favor if the cost recovery is not guaranteed. Both alternatives have pros and cons in terms of encouraging new investment. In this section, we review the recent experience in Virginia and Maryland in terms of attracting new generation.

8.1.5.1 Virginia

According to the SCC, twelve plants totaling 4,450 MW have been commercialized in Virginia over the past decade. As shown in Table A3 of the Appendix, 1,800 MW (about 40%) are owned by DVP. Nearly all generation entry was commercialized prior to 2002, except for 16 MW of landfall gas capacity added in 2004 and 300 MW of GT capacity added by DVP in 2007. The SCC has also granted certificates to construct six additional facilities totaling 3,865 MW. Four of these projects were not developed, and their certificates have expired, and DPV purchased the development rights to the remaining two. Three other certificate applications have been granted by the SCC, totaling 774 MW. The respective projects, including a 39-MW wind turbine facility, a 150-MW GT extension, and a 585-MW circulating fluidized bed coal facility, are in various stages of development. Both the GT extension and the circulating fluidized bed facility are DVP projects.

Currently, DVP's Bear Garden combined-cycle facility in Buckingham County is pending before the SCC.[76] DVP is also assessing the possible construction of up to two more nuclear units at the North Anna Power Station. In 2003, DVP filed an application with the Nuclear Regulatory Commission (NRC) for an early site permit that was approved in November 2007. Shortly thereafter, Dominion submitted an application to the NRC for a combined operating license at North Anna, but DVP's proposed new nuclear unit at North Anna was not selected by DOE in February 2009 as a finalist for government-backed loans, thus reducing its chances of being built. Many existing power plant upgrades and a few new projects in the Dominion zone have taken and maintain active PJM interconnection queue positions as shown in Table A4 of the Appendix. However, based on history, the number of projects on the interconnection queue that are actually built and commercialized is likely to be significantly lower.

Since joining PJM in May 2005, there has been virtually no merchant entry in DVP's service territory or elsewhere in Virginia. While there has been merchant entry in Virginia prior to its membership in PJM in 2005, there has not been merchant entry since DVP joined PJM.

8.1.5.2 Maryland

Over the last ten years no significant generation has been added to the resource mix in Maryland.[77] According to the Brattle Group, no new generation has cleared in the SWMAAC LDA for the first four RPM auctions; 101 MW cleared in the 2011/12 auction. Siting challenges may have deterred new entry in Maryland. Although SWMAAC has had high energy and capacity prices, we believe that the threat of new generation (Calvert Cliffs) or transmission (TrAIL) projects would cause those prices to collapse, further deterring new entry.

In the last five years, the Commission has granted several Certificates of Public Convenience and Necessity (CPCNs) for generation projects in Maryland. Table A5 of the Appendix provides a listing of the new generation facilities proposed for construction in Maryland and their CPCN status. Many of the proposed projects made good progress fulfilling certain conditions of their respective CPCN requirements, but faced regulatory sunsets requiring the commencement of construction.

Another proposed project is the 640-MW combined-cycle St Charles Project sponsored by CPV Maryland. CPV has argued before FERC that it required a ten-year term for New Entry Pricing in the RPM so that it could secure a stable capacity revenue stream, and its senior management has testified before the Maryland Senate Finance Committee that long-term contracts with one or more IOUs would be required in order to support the attraction of capital that would permit successful development of the project.

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[76] Case No. PUE-2008-00014, SCC Report to the Commission on Electric Utility Regulation of the Virginia General Assembly and the Governor of the Commonwealth of Virginia "Status Report: Implementation of The Virginia Electric Utility Regulation Act Pursuant to § 56-596 B of the Code of Virginia," September 1, 2008.

[77] The only sizeable new generation built in Maryland is the Warrior Run cogeneration facility in 1999 (180 MW-Summer) and the Rock Springs generating facility in 2003 (632 MW-Summer), both of which were planned before deregulation.

Since deregulation in 1999, essentially no newly planned generation has been built in Maryland, but the key variable may be membership in PJM rather than whether generation was regulated. Based on the comparison with neighboring Virginia, it is not possible to explain the lack of new entry based on whether the state adopted rate base regulation. Elsewhere in PJM, there has been limited merchant entry as well. LAI believes that low and uncertain capacity prices, PJM's commitment to backbone transmission projects, and generally unfavorable conditions in the capital markets have impaired merchant entry across PJM, Virginia included. For this reason, we cannot conclude that the lack of merchant entry is attributable to the presence or absence of rate base regulation.

8.1.6 Wholesale Markets in Regulated and Deregulated States

The following sections survey the effects in several representative states of regulation and deregulation on wholesale markets.

8.1.6.1 Virginia

Virginia did not require jurisdictional utilities, such as DVP, to divest its generation assets. Since DVP has remained a vertically integrated IOU, examination of the Virginia experience provides useful information regarding the impact of rate base regulation on wholesale market dynamics. In LAI's view, there is no compelling evidence to date that indicates that SCC jurisdiction of DVP's generation plants under cost-of-service regulation has distorted wholesale energy prices in DVP's service territory, elsewhere in Virginia, or in PJM. The SCC's jurisdiction over DVP's rates has not impaired DVP's ability to procure a portion of its resource needs from other generators in Virginia or PJM.

Excess capacity in many parts of PJM has caused capacity prices to drop substantially below Net CONE. A portion of the excess capacity may be attributable to the ability of vertically integrated IOUs under rate base regulation to add new resources prior to the need date. In LAI's opinion, DVP's ability to add new generation investment provides the incumbent utility with a significant competitive advantage over merchant generators, thereby "stacking the deck" against merchant entry in both the short and long term. The addition of third-party resources in DVP's zone will likely require SCC approval for long-term contracts in order to provide the requisite credit to support the addition of conventional as well as renewable resources.

8.1.6.2 Ohio

A 1999 law restructured Ohio's electric industry by changing the way customers shop for electricity. The law took effect in 2001 and provided a five-year market development period, during which utilities' rates were frozen to allow a competitive resale market to develop. As the end of the market development period neared, there was a growing concern that an immediate shift to market-based rates in 2006 would adversely affect retail customers due to the limited number of competitive electric suppliers. To ease the transition to market-based prices, the Public Utilities Commission of Ohio worked with Ohio's electric utilities to develop Rate Stabilization Plans.

The Rate Stabilization Plans, coupled with other rate modifications, eliminated market uncertainty and provided customers with stable, predictable rates through 2008. The Ohio governor and legislative leaders worked to pass Senate Bill 221 to keep electric rates stable going forward, create jobs, and expand Ohio's green energy industry. The new law incorporated a system under which rates would be set by the Ohio Commission beginning January 2009, with a future transition to market-based rates.

On July 31, 2008, AEP, Duke Energy, FirstEnergy, and Dayton Power and Light filed applications at the Ohio Commission to establish their Electric Security Plans to comply with Senate Bill 221. The companies' Plans cover the supply and pricing of electric generation service over the next three years. The goals of the plans include price stability, ensuring an adequate supply of electricity, promoting economic development, job retention, energy efficiency and conservation. Nearly all generation in Ohio is subject to rate base regulation. Resource additions needed to maintain PJM reliability criteria are likely to be subject to traditional cost-of-service regulation under Ohio Commission jurisdiction. LAI has observed no negative consequences for wholesale markets from Ohio's use of rate base regulation.

8.1.6.3 New Hampshire and Vermont

While most of New England's IOUs have divested their generating assets, Public Service Company of New Hampshire (PSNH) continues to own and operate generation plants under rate base regulation. PSNH also purchases in excess of 30% of the default energy service requirements from the ISO-NE wholesale market. Vermont is the only state in New England where regulated utilities are not precluded by law or state policy from owning, building or acquiring new electric generation facilities.

Our brief review of energy prices across New England does not confirm that there is an advantage or disadvantage associated with rate base regulation. Energy prices in New Hampshire and Vermont are predictably lower than in the transmission-constrained portion of New England – *e.g.*, the Connecticut / Boston load pockets – but they are not significantly lower than energy prices elsewhere in the region. Tables A6 and A7 in the Appendix illustrate how the DAM LMPs in the top 250 hours of the year 2008 differed in Vermont, New Hampshire, and unconstrained Western and Central Massachusetts.

Capacity prices are set through New England's FCM, where all states, except for the export-constrained Maine, are included in a single capacity zone. Resource additions needed to maintain ISO-NE resource adequacy requirements are subject to state commissions' siting permits and may be subject to approved long-term contracts for both conventional and renewable resources. Nothing in the rate base regulation in Vermont or New Hampshire has hampered the operation of the wholesale capacity market in those states or in New England.

8.1.6.4 Conclusions About the Impact of Rate Base Regulation on PJM's Wholesale Markets

So long as state regulatory commissions do not permit jurisdictional utilities to "pad" rate base with facilities that are not used and useful, a return to rate base regulation should not result in unneeded capacity, which would distort energy and capacity prices and deter timely and cost-effective merchant additions. Nevertheless, compensating generators under rate base regulation reinforces a strong incentive to build because utility owners are insulated from wholesale price fluctuations and other market risks. The breakdown in the capital markets and recent credit implosion make it more difficult for new merchant resources to attract financing on competitive terms absent long-term contracts with creditworthy counterparties. Such counterparties are more likely to be utilities that have received state regulatory commission approval to pass through contract costs to retail customers.

Returning the Mirant assets to rate base regulation in Maryland would be expected to deter merchant entry in Pepco territory and, perhaps, elsewhere in SWMAAC. In LAI's opinion, the re-regulation of the Mirant assets would likely put Pepco or the Authority in an advantageous position to add generation resources and/or DR in the future to satisfy local area reliability requirements. There is no reason, however, that, in order to maintain grid reliability objectives, Pepco or the Authority could not consider long-term contracts rather than owning and operating new resources. Consistent with Commission policy, the approval of resource additions can be evaluated in a fair and transparent manner.

To the extent such resources required long-term contracts, we assume that the Commission would allow Pepco or the Authority to pass through to load all reasonably incurred costs arising under such an agreement. Merchant generators likely would be averse to competing alongside vertically integrated IOUs who enjoy a reasonably assured rate of return, particularly if the Commission were to approve a petition to add resources prior to the need date. The addition of new resources from time to time in order to preempt capacity shortfalls in SWMAAC may cause future capacity prices in PJM to decrease relative to Net CONE values under RPM.

In the long run, the declining share of merchant generation in relation to the total resource mix would likely lessen the competition between IOUs and merchant generators in Pepco LDA and, perhaps, SWMAAC. Based on the experience we observed in other states with rate base regulation within an RTO's wholesale market structure, the prospect of a "domino effect" at the wholesale level alluded to in the Task 3 Report appears more unlikely than likely.

Notwithstanding the potential coexistence of rate base regulation and the competitive wholesale market design in PJM, should Pepco or the Authority acquire the Mirant assets, new resource additions required in Pepco's territory and, perhaps, that of BGE, would almost certainly require either rate base regulation or long-term contracts. In the long run, the wholesale market in Maryland may increasingly drift toward non-competitive, inefficient solutions unless regulatory mechanisms are designed to level the playing field for all market participants. We express skepticism about the effectiveness and sustainability of such measures because there is no good substitute for a stable, guaranteed revenue flow under either rate base regulation or long-term contracts. Hence, the cost of capital that applies to regulated generation would surely be much lower than that applicable to merchants who must rely on wholesale price signals under the RPM to support project financing.

8.2 Impact of Rate Base Regulation on Retail Markets

There are many complex, logistical challenges associated with the return of the Mirant assets to rate base regulation. In the Task 3 Report, LAI did not consider the apportionment of benefits and costs to different rate classes following the acquisition of the generation assets by Pepco or the Authority. Implicit in prior technical review was the ability of Pepco or the Authority to pass through to all retail customers the total costs and the commensurate benefits arising from the return to rate base regulation. Large commercial and industrial (C&I) customers would be an integral part of the total Pepco retail load that would be expected to bear their proportionate share of the costs and the benefits arising from this initiative.

As shown in Section 7, there is broad dispersion in the range of economic outcomes relative to the expected value of the EVA resulting from rate base regulation. Potential economic outcomes associated with the return to rate base regulation include a number of bad results. If, for the sake of argument, the benefit of the bargain were to "sour" relative to the *pro forma* estimate of benefits used to support the FMV of the Mirant assets, we have assumed that the Commission would nevertheless allow Pepco or the Authority to pass through to retail load all of the fixed and variable costs associated with operating these generation plants. Absent such clear and iron-clad regulatory authorization to pass through such costs to load irrespective of changes in market prices and environmental regulation over the next twenty years, the ability of either Pepco or the Authority to attract capital on reasonable pricing terms would be materially impaired.

In this section, we explore whether retail competition will dry up following the return to rate base regulation of the Mirant fleet. We also assess whether it would be possible or desirable to administer the existing SOS procurement framework once the Mirant assets are subject to rate base regulation.

8.2.1 Status of Retail Electric Choice in Maryland

A recent examination undertaken by the Commission of the number of customers using a competitive supplier shows that residential customers have not participated in the transition to retail competition. Only about 3% have migrated to competitive suppliers; the other 97% are served by the IOU. According to the Commission, electric choice has been most successful for large C&I customers, consistent with other utilities in and outside of PJM. The most recent choice enrollment report shows that only about 5% of total utility distribution customers take service from a competitive energy supplier. According to the Commission's website, 87.3% of the total number of large C&I customers have switched to competitive suppliers.[78] The amount of total electricity load associated with residential and small C&I customers that switched to competitive suppliers can be characterized as small.

Pepco continues to experience the highest degree of retail supplier participation on a percentage basis with about 6% of residential accounts and 32% of C&I accounts served by competitive suppliers. Between December 2005 and November 2008, the total number of customers statewide served by competitive retail electricity suppliers increased substantially.[79] This large

[78] As of end of November 2008, of the roughly 2.2 million electricity accounts statewide, there were 112,593 customers served by competitive electric suppliers: 56,357 were residential, 30,379 were small C&I, 24,561 were mid-sized C&I, and 1,296 were large C&I customers.

[79] According to the Commission website, the number of customers served by competitive suppliers grew from 39,527 to 112,593.

increase in customer choice is explained by the higher BGE SOS rates. The number of customers served by electricity suppliers in BGE's service territory increased fourteen-fold from 2005 to 2008. On a statewide basis, at the end of November 2008, electric suppliers served 3.3% of eligible residential peak load and 71.6% of eligible non-residential peak load obligations.

8.2.2 Competitiveness of Retail Markets

Large C&I customers in Maryland have competitive options relative to traditional reliance on Maryland's IOU's for full requirements service. Each of Maryland's IOUs must actively procure energy, capacity, ancillary services, and renewable energy credits to serve residential and small commercial customers, in particular. Historically, competitive retail service providers in Maryland have not been actively seeking increased market share in the residential and small commercial markets. Although any significant increase in the SOS prices is likely to trigger more competitive suppliers' interest in expansion of their market share, LAI expects each of Maryland's four IOUs to continue to procure full requirements service at regular intervals under the existing SOS procurement framework, at least in the short to intermediate term.

At present, vertically integrated utilities who are net buyers, such as DVP, supply their native load by a combination of their own generation and energy and capacity purchases from the wholesale markets. Reliance in part on the DAM or RTM is an integral part of vertically integrated utilities' active portfolio management to serve retail customers. At present, only one competitive service provider, Pepco Energy Services, currently provides any service in DVP's service territory, and its market share in Virginia is trivial.[80] There are no competitive service providers in Ohio, where regulated utilities predominate. As we understand it, competitive retail service providers in New Hampshire, Vermont, and California do not have a significant market share in those zones where vertically integrated utilities serve retail load. In relation to these other jurisdictions, we see no reason why Maryland's experience would be any different if the Mirant assets were subject to rate base regulation.

If return to rate base regulation achieves the objective of reducing IOU electricity prices compared to the market prices in the long run, the major incentive of competitive suppliers to offer will not exist. Therefore, following the return to rate base regulation in the Pepco LDA, it is reasonable to expect the interest of retail service providers to wane in the competition for market share. While a competitive supplier may be able to maintain or, conceivably, expand market share in the initial going following the return of the Mirant fleet to rate base regulation when regulated prices exceed market prices, this paradox would manifest the profound failure of re-regulation. In our view, success of re-regulation is incompatible with the success of retail competition. A retail service provider's transient success during the transitional period when SOS prices might exceed market prices would not be sustainable once SOS prices decrease as the rate base declines. Who bears what cost during the transition to lower electricity prices under rate base regulation raises complex questions about efficiency and fairness that LAI has not explored in this study.

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[80] According to the SCC, Pepco Energy Services serves 1,211 residential customers and 18 commercial customers under "green power" arrangements. *Status Report: Implementation of the Virginia Electric Utility Regulation Act*, September 1, 2008.

If an IOU or an Authority were to acquire the Mirant assets, either entity should be able to supplement the generation output from these resources by entering into bilateral contracts with other generation companies in Maryland and/or PJM, as well as relying on the DAM / RTM. The resultant managed portfolio of generation resources would be managed by the IOU or the Authority to serve the retail load obligation. Consistent with conventional cost minimization objectives, the IOU or the Authority would be expected to manage the portfolio in order to minimize the cost of service to retail customers.

Unless the IOU or the Authority were willing to sell slices of the portfolio or the portfolio itself to retail service providers serving Pepco's retail customers, rival suppliers would not be able to obtain the "parts" needed to provide a competitive service. We cannot envision why the IOU or an Authority would ever agree to sell slices of the portfolio to a retail service provider or other market participant. For this reason and others, competitive retail service providers are not serving the mass market in other jurisdictions that have vertically integrated utilities. Even, for the sake of argument, if an IOU or the Authority were required to sell entitlements to the existing Mirant generation assets to competitive retail service providers, how would such entitlements be priced? If the price were to reflect cost of service and the cost-of-service-based rate were higher than the market price, it is not likely that the competitive supplier would be willing to incur the higher cost in order to serve retail load. Conversely, if the price under cost-of-service regulation were lower than the market price, competitive retail suppliers would welcome the potential financial gain, but there would be no guarantee that any portion of the savings would ultimately be allocated to retail customers.

While long-term entitlements might induce competitive suppliers to pay a short-term premium in exchange for the risk management benefits over the long term, the prospect of default risk would necessitate performance guarantees, credit assurance, and other forms of collateral. Under the best of circumstances it would be expensive for competitive suppliers to obtain the requisite credit assurance to satisfy either Pepco's or the Authority's credit requirements governing long-term performance. In the current credit environment, the procurement and retention of such credit assurance in the context of a long-term contract entitlement would represent a formidable challenge for any market participant, in particular, thinly capitalized competitive retail service providers.

Particularly when prices under rate base regulation are lower than the retail price offered by competitive suppliers, customers would be expected to migrate back to the IOU or the Authority, thereby drying up any remaining competitive supply. If the Commission were to allow large C&I customers to remain under competitive retail supply arrangements, there would be less full requirement load over which to apportion the fully allocated cost of service following the return to rate base regulation. Those residential and small commercial customers who continue to rely on the IOU for full requirements service would potentially face disproportionately high retail rates for an interim period before large C&I customers switch back to utility service. Alternatively, the Commission could require large C&I customers to incur a non-bypassable surcharge associated with the return to retail service, but the creation of this surcharge might not be favorably received by large customers preoccupied with survival during hard economic times.

As shown in Figure 57 in Section 7, wholesale prices under rate base regulation would be higher on a risk-adjusted basis under IOU ownership for first eight years. The benefits of rate base regulation are back-end loaded. This raises the question of whether larger C&I customers who have elected to do business with competitive suppliers should be permitted to continue to enjoy the benefits of market-based rates, only to migrate back to the IOU when the economic benefits begin to materialize after debt service has been repaid. Under rate base regulation, the IOU or the Authority would still need to manage price and volume risk through active portfolio management. These risks would be heightened and the management burden made more complex in response to the potential ability of large C&I customers' ability to migrate back and forth when price signals warrant.

Significant administrative and stranded costs associated with the customers' migration back and forth between cost of service and the competitive supplier option would be detrimental for those customers who have not switched from the cost of service option. These costs would add to the presumably lower SOS costs making cost of service option less attractive. Some measures designed to protect the IOU ratepayers would have to be implemented. Most likely, the measures would raise barriers for switching from cost of service to the competitive suppliers, thereby hurting retail competition.

Retail competitive markets thrive when customers have an option to choose among competitive suppliers. If competitive suppliers cannot obtain generation entitlements sufficient to cover their portfolio of retail loads, they cannot offer a competitive price. If the Mirant assets in Maryland are owned by the IOU or the Authority, retail suppliers would not be expected to be able to purchase all or a portion of the generation output needed to backstop their retail portfolios. While other generation assets located elsewhere in Maryland, SWMAAC, or PJM may still be available at market prices, we would not expect competitive service providers to attract market share from Pepco or the Authority. Following the return to rate base regulation of the Mirant assets, in our view the retail competitive market in the Pepco LDA would soon wind down.

LAI would expect the existing SOS contracts that Pepco has entered into to serve retail customers to run their respective course. It would not be financially feasible to incur breakage fees associated with termination of the existing SOS contracts prior to the contract end dates. Full requirements suppliers under the SOS procurement framework manage a number of risk management and procurement functions in order to serve a utility's retail customers, *i.e.*, market price, quantity, weather risk, migration risk, credit assurance, among other things. Under rate base regulation, either the IOU or the Authority would bear the responsibility of assembling the complement of services to meet and manage customer obligations. The cost of obtaining this management expertise would be significant, particularly for a newly created Authority.

LAI has not identified a workable alternative that would allow for the existing SOS procurement paradigm to be administered successfully by the Commission and the IOU following the return to rate base regulation. Whether or not the demise of the competitive retail market in the Pepco LDA would endanger retail competition next door in the BGE zone, or, for that matter elsewhere in Maryland, has not been determined.

8.3 Impact on Maryland's Cost of Capital (Authority Case)

As we pointed out in the Task 3 Report, an Authority debt issuance to acquire the Mirant assets would dwarf the MdTA's total indebtedness that stood at $1.07 billion as of June 30, 2007, and

$1.91 billion as of June 30, 2008. Based on the FMV of about $5 billion, an Authority debt issuance would be comparable to Maryland's total GO indebtedness of $5.49 billion as of June 30, 2008. An Authority's issuance of this size raises a question about whether bond investors have sufficient appetite for Authority revenue bonds, given that the primary market is Maryland residents and institutions that can enjoy the state and local exemption from income taxes.

LAI has not estimated the potential impacts on higher GO and revenue bond costs due to an Authority bond issuance. We believe, however, that the State and its debt-issuing agencies would be affected. In addition to the State's issuance of GO bonds, various State agencies are authorized to and have issued revenue bonds: the MdTA, the Maryland Stadium Authority, Grant Anticipation Revenue Vehicle for non-traditional debt, the University System, the Community Development Administration, among others. We note that the State of Maryland has been highly protective of its AAA credit ratings.

8.4 Coal Plant Operational Risks

Even though the Mirant coal plants have been well maintained and have achieved good performance and high availability, operating problems may ensue over the next 20-years due to the advanced age of the fleet (see Table 4 on page 21) and the possibility of stricter environmental compliance standards. Routine problems are adequately monetized in the O&M budget figures and plant availability projections. There are other risks inherent in the operation of a pulverized coal plant, however, that have more serious consequences, often due to the dangers of high pressures / temperatures of superheated steam, high-power machinery, and flammable or noxious gases.[81] Such events are rare, and indeed a significant part of the responsibilities of the plant O&M personnel is to prevent them entirely, but they do sometimes occur despite preventative maintenance. The consequences of these types of risks are serious enough that they should be considered separately, distinct from normal plant operations and routine O&M expenses. While insurance often covers most of the direct repair costs, it would be unusual for an owner to avoid significant CapEx. In addition, catastrophic events can impose significant indirect / consequential costs on plant owners, such as loss of revenue during plant outages.

It is not possible to foresee everything that can go wrong over the 20-year valuation period. Serious problems can cover a broad range of events that require wholesale replacement of entire systems.[82] However, we do present a sample list of the types of serious accidents that have occurred in the past, the consequences of these types of accidents, and, if possible, whether or not the conditions at the Mirant stations would make this type of accident more or less probable.

[81] This section was developed based on publicly available information. Given the sensitivity associated with major accidents regarding insurance claims and potential legal liabilities, especially if there is a loss of life, detailed information is often kept confidential.

[82] See http://ecmweb.com/mag/electric_series_preventable_events/ for a description of how a stopped-up toilet led, through a sequence of improbable events, to an explosion that destroyed the boiler at Kansas City Power & Light's Hawthorn 5 unit, causing estimated damages and lost revenue in excess of $500 million and taking the unit off-line for over two years.

- Steam plant boilers, fired by coal or other fossil fuels, rely on tubes (in which water is converted into high-pressure steam) that can rupture if the pressure is too high or the tube material becomes thin or weakened. Boiler tube failures are the most common failure that can lead to forced outages and unexpected repair costs. While some ruptured tubes can be plugged temporarily and replaced during major overhauls, other ruptures are tantamount to explosions and can reduce performance or cause reduced localized damage to the boiler. Boiler explosions can be characterized by costs in the tens of millions of dollars and require many months off-line, depending on the severity of damage.

- Coal plants contain pulverizers that grind coal into a powder to aid in fuel handling and combustion. Coal dust is highly flammable and explosions can occur anywhere there is a sufficient concentration of coal dust confined in suspension, especially in the fuel feed system. Coal dust explosions can (and have) caused loss of life, but physical damage is usually moderate and confined to the particular piece of fuel feed equipment. A coal dust fire or explosion can be characterized by costs in the hundreds of thousands to millions of dollars and days or weeks off-line. One source has estimated the frequency of coal dust explosions in the U.S. at roughly one per year in a domestic population of approximately 1,000 coal-fired generating units.[83]

- Hydrogen is often used to cool electrical generators, especially medium-to-large sizes, due to its low density, high specific heat, and thermal conductivity A hydrogen fire or explosion can occur in storage / refill areas, feed lines, cooling equipment, or the generator itself. Physical damage tends to be minor and repairs are usually completed promptly unless the generator itself is involved.

- Structural failure of a large steam turbine can destroy the turbine. In a worst case scenario, the failure can release fragments that penetrate the outer casing and act as projectiles that can damage neighboring pieces of equipment. While some wear and tear of steam turbine blades, nozzles, and seals is expected, a major steam turbine failure can destroy the turbine and require the turbine rotor to be re-bladed, a process that requires tens of millions of dollars and 2 to 3 months off-line.

- Dangerous gases may be kept on site, such as ammonia for NO_x control or chlorine for water treatment. An accidental release of those gases can have serious consequences for people nearby, and potential legal liability. There is generally little or no physical damage to plant, and relatively minor clean-up costs.

- The principal risk associated with ash disposal is an accidental release of contaminants due to leachate runoff. This can result in a legal / environmental liability, rather than a direct impact on the plant or its operations. The Mirant plants dispose of ash in dedicated landfills that we believe utilize up-to-date control and monitoring of leachate runoff, but a

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[83] http://www.coalpowermag.com/plant_design/79.html

potential liability exists nonetheless for any ash disposal sites that are transferred with the power plants.[84]

8.5 Risks of Condemnation

Unless Mirant agrees to voluntarily negotiate the purchase and sale of the Maryland generation assets to an IOU or an Authority, any acquisition would require the IOU or the Authority to use the State's condemnation powers. As Kaye Scholer described in the December 1, 2008, Task 2 Report, if Maryland were to re-regulate by requiring its utilities to purchase the generation assets that they divested in 2000, it may have to do so by using the State's condemnation powers, in which case it would be required to compensate the owners at the FMV. Maryland has the "inherent" power to condemn privately owned property, so long as the taking "be for public use and that just compensation be paid." *City of Baltimore Dvlpt. Corp. v. Carmel Realty Associates, et al.*, 910 A.2d 406, 415-416 (Md. 2006), citing *Matthews v. Maryland-National Capital Park and Planning Commission*, 792 A.2d 288, 297 (Md. 2002) and *Utilities, Inc. of Md. v. Washington Suburban Sanitary Commission*, 763 A.2d 129, 133 (2000)).[85] "Public use" does not require that the public actually use the condemned property, but requires only that the condemned property serve a "public purpose," which is defined broadly. *Kelo v. City of New London*, 545 U.S. 469, 480 (2005). The Maryland Constitution requires that just compensation be "agreed upon between the parties, or awarded by a Jury." MD. CONSTITUTION, Art. III § 40. Just compensation would undoubtedly be based on FMV, (MD. CODE ANN., REAL PROPERTY § 12-105(b)), and would be determined as of the date the taking occurs or the date of the trial. *Id.* § 12-103. FMV would be based, at least in part, on the expected stream of earnings for the plants' remaining operating lives.[86]

Two factors in the condemnation process would create substantial risk. First, there will be an inevitable delay between the decision to undertake condemnation proceedings and any determination of FMV. As the differences between the FMV in the Task 3 Report and this report illustrate, economic and market conditions can cause the FMV to change significantly in only a few months. Second, under Maryland law, the value in a condemnation proceeding will be determined by a jury. A lay jury that is not familiar with the principles of valuation may make that decision based on factors that may vary significantly from those that the IOU or Authority used in determining the FMV. Consequently, the award in a condemnation proceeding may not

[84] Some generating facilities dispose of ash sludge in holding ponds, which entail a separate risk such as the recent failure at a TVA plant. This particular risk is not relevant for the Mirant plants, which do not use large holding ponds for ash disposal.

[85] Electric utilities' may also condemn property for public purposes, but that right is tied to the requirement for a CPCN. MD. CODE ANN., PUB. UTIL. COS. § 7-207(b)(2) (2007); *see County Commissioners of Frederick County v. Schrodel*, 577 A.2d 39, 47 (Md. 1990) (citing repealed Art. 78 54A, which contained the same requirements as § 7-207), *Bouton v. The Potomac Edison Co.*, 418 A.2d 1168, 1169 (Md. 1980) (same). It is unclear how this requirement would apply when condemnation is of existing generation facilities rather than to build new facilities.

[86] *See* Direct Testimony and Exhibits of John O. Sillin on Behalf of the Staff of the Public Service Commission of Maryland, *In the Matter of Baltimore Gas and Electric Company's Proposal to Implement a Rate Stabilization Plan*, Case No. 9099 (Mar. 30, 2007) at 23:10-12 ("[t]he price that investors are willing to pay for [coal-fired] facilities [recently sold in PJM and elsewhere] reflects not their age or their book value, but the returns they believe can be earned on these plants from future operations").

strictly adhere to the principles of intrinsic valuation of generation assets, creating a risk that the IOU or Authority may be forced to overpay in order to acquire Mirant's existing generation fleet in Maryland.

APPENDIX

Impact on Regional Markets – Data Tables

Based on the price duration curves presented in Figure 69 of Section 10, we have developed a statistical analysis that helps to better understand how quantitatively the day-ahead LMP values differ in different load zones at various ranges of the prices. Table A1 illustrates the prices, in $/MWh, in the four selected load zones for the five postulated ranges of hours: (1) 0-50 hours; (2) 50-100 hours; (3) 100-150 hours, (4) 150-200 hours, and (5) 200-250 hours. Table A2 shows the same values in terms of percent of the corresponding range's DVP prices assumed as the 100% base.

Table A1. Price of Top Marginal Hours

Zone	50th	100th	150th	200th	250th
Pepco	$276	$237	$212	$197	$186
DOM	$219	$196	$184	$173	$166
AP	$186	$163	$152	$144	$138
AEP	$149	$136	$127	$121	$115

Table A2. Relative Price of Top Marginal Hours

Zone	50th	100th	150th	200th	250th
Pepco	126%	121%	115%	114%	112%
DOM	100%	100%	100%	100%	100%
AP	85%	83%	83%	83%	83%
AEP	68%	69%	69%	70%	70%

Table A3 presents a summary of the construction activity in Virginia, as of August 1, 2008, as reported by the Virginia SCC. Table A4 presents a summary of the PJM queue in the Dominion Zone.

Table A3. Summary of Construction Activity in Virginia, As of August 1, 2008[87]

Company/Facility	Size (MW)	Location (County)	Docket	Fuel	COD	Hearing	Order
		New Power Plants In Operation					
Commonwealth Chesapeake	300	Accomack	PUE960224	3-OilCT	sum 01	1/23/1997	8/5/1998
Dominion Virginia Power	600	Fauquier / Remington	PUE980462	4-GasCT	sum 00	1/5/1999	5/14/1999
Wolf Hills Energy, LLC	250	Washington / Bristol	PUE990785	5-GasCT	sum 01	4/27/2000	5/2/2000
Dominion Virginia Power	360	Caroline / Ladysmith	PUE000009	2-GasCT	sum 01	5/23/2000	10/10/2000
Doswell Limited Partnership	171	Hanover / Doswell	PUE000092	1-GasCT	sum 01	6/13/2000	6/15/2000
Allegheny Energy Supply	88	Buchanan	PUE010657	2-C/GCT	2-Jun	none	6/25/2002
Dominion Virginia Power-Possum	540	Prince William / PP	PUE000343	convert/GasCC	3-May	1/16/2001	3/12/2001
Louisa Generation, LLC (ODEC)	472	Louisa / BoswllTavrn	PUE010303	5-Gas CT	3-Jun	11/14/2001	7/17/2002
Tenaska Virginia Partners I, LP	885	Fluvanna	PUE010039	Gas CC	4-May	3/13/2002	4/19/2002
INGENCO Wholesale Power, LLC	16	Chesterfield	PUE-2003-00538	48-LFGas	4-Jun	none	4/12/2004
Marsh Run Generation, LLC (ODEC)	468	Fauquier	PUE020003	3-GasCT	4-Sep	5/21/2002	11/6/2002
Dominion Virginia Power	300	Caroline	PUE-2007-00032	2-dualCT	8-Jun	none	8/24/2007
Total	**4,450**						
		Power Plants Granted SCC Certificates					
Highland New Wind Development	39	Highland	PUE-2005-00101	19-wind	fall 07	7/17/2007	SCC app 12/20/07
Dominion Virginia Power	150	Caroline	PUE-2007-00032	1-dualCT	sum 09	none	SCC app 3/19/08
Dominion Virginia Power	585	Wise	PUE-2007-00066	CFBCoal	sum12	1/8/2008	SCC app 3/31/08
Total	**774**						

[87] Source: Virginia SCC Report to the Commission on Electric Utility Regulation of the Virginia General Assembly and the Governor of the Commonwealth of Virginia "Status Report: Implementation of The Virginia Electric Utility Regulation Act Pursuant to § 56-596 B of the Code of Virginia" dated September 1, 2008.

Company/Facility	Size (MW)	Location (County)	Docket	Fuel	COD	Hearing	Order
New Power Plants That Have Applied For An SCC Certificate							
Appalachian Power Company-Financing	(629)	Mason (WV)	PUE-2007-00068	IGCC	sum12	2/12/2008	SCC deny 4/14/08
Tenaska Virginia Partners II, LP	(900)	Buckingham	PUE010429	Gas CC	n/a	5/28/2002	SCC app 1/9/03[88]
Dominion Virginia Power	580	Buckingham	PUE-2008-00014	Gas CC	sum10	9/30/2008	pending
CPV Warren, LLC (3/07 renewal)	(520)	Warren	PUE-2007-00018	2-GasCC	spr 05	7/24/2002	SCC renew 6/20/07[89]
Total	**580**						

[88] Renewal extended 1/8/07, site sold to DVP – see PUE-2008-00014
[89] Site sold to DVP 3/4/08, not yet filed

Table A4. Summary of the PJM Queue in Dominion Zone

Queue	Queue Date	PJM Substation	Total MW	Incr MWC	Status	State	In Service	Fuel	County	Transmission Owner
O06_DP01	2/24/2005	Altavista 115kV	84	4	Partially In-Service	VA	2006 Q2	Wood	Pittsylvania	Dominion
P16	10/19/2005	Bath County	3030	340	Partially In-Service	VA	2006 Q2	Hydro	Bath	Dominion
R63	1/11/2007	Chesterfield 230kV	336	19	In-Service	VA	2007 Q1	Coal	Chesterfield	Dominion
Q09	2/21/2006	Emporia	3	2.5	Under Construction	VA	2007 Q2	Hydro	Greensville	Dominion
S50	5/24/2007	Occoquan 230kV	98	18	Partially In-Service	VA	2007 Q2	Methane	Fairfax	Dominion
Q70	7/25/2006	Lawrenceville 34.5kV	11	11	In-Service	VA	2007 Q4	Methane	King and Queen	Dominion
T10	8/15/2007	Cranes Corner 34.5KV	3	3	Under Construction	VA	2007 Q4	Methane	Stafford	Dominion
P27	11/18/2005	Winchester 34.5 kV	13	13	In-Service	VA	2008 Q1	Methane	s	Dominion
Q69	7/25/2006	Shackleford 34.5kV	10	10	In-Service	VA	2008 Q1	Methane	Brunswick	Dominion
U1-032	2/20/2008	Hopewell 230kV	113	0	Active	VA	2008 Q1	Coal	Hopewell City	Dominion
Q71	7/26/2006	Cranes Corner 13.2kV	2		Under Construction	VA	2008 Q2	Methane	Stafford	Dominion
R19	10/3/2006	Ladysmith 230kV	720	340	Under Construction	VA	2008 Q2	Natural Gas	Carolina	Dominion
R31	10/30/2006	Hopewell 230kV	18	8	Active	VA	2008 Q2	Natural Gas	Hopewell City	Dominion
R80	1/26/2007	Possum Point 230kV	633	60	Active	VA	2008 Q2	Natural Gas	Prince William	Dominion
S86	7/31/2007	Darbytown 230kV	92	20	In-Service	VA	2008 Q2	Natural Gas	Henrico	Dominion
S87	7/31/2007	Darbytown 230kV	93	20	In-Service	VA	2008 Q2	Natural Gas	Henrico	Dominion
S88	7/31/2007	Darbytown 230kV	92	20	In-Service	VA	2008 Q2	Natural Gas	Henrico	Dominion
S89	7/31/2007	Darbytown 230kV	92	20	In-Service	VA	2008 Q2	Natural Gas	Henrico	Dominion
S90	7/31/2007	Elizabeth River 230kV	125	20	In-Service	VA	2008 Q2	Natural Gas	City of Chesapeake	Dominion
S91	7/31/2007	Elizabeth River 230kV	125	20	In-Service	VA	2008 Q2	Natural Gas	City of Chesapeake	Dominion
S92	7/31/2007	Elizabeth River 230kV	125	20	In-Service	VA	2008 Q2	Natural Gas	City of Chesapeake	Dominion
S93	7/31/2007	Remington 230kV	190	15	In-Service	VA	2008 Q2	Natural Gas	Fauquier	Dominion
S94	7/31/2007	Remington 230kV	190	15	In-Service	VA	2008 Q2	Natural Gas	Fauquier	Dominion
S95	7/31/2007	Remington 230kV	190	15	In-Service	VA	2008 Q2	Natural Gas	Fauquier	Dominion
S96	7/31/2007	Remington 230kV	190	15	In-Service	VA	2008 Q2	Natural Gas	Fauquier	Dominion

Queue	Queue Date	PJM Substation	Total MW	Incr MWC	Status	State	In Service	Fuel	County	Transmission Owner
T104	11/15/2007	Gosport 115kV	50		In-Service	VA	2008 Q2	Other	Portsmouth City	Dominion
U2-056	6/30/2008	West Point	89	88.7	Active	VA	2008 Q2	Other	King William	Dominion
U2-057	6/30/2008	Hopewell 34.5kV	48	47.6	Active	VA	2008 Q2	Other	Hopewell City	Dominion
P09	9/14/2005	Kerr Dam 115kV	91	91	Under Construction	VA	2008 Q3	Hydro	Mecklenburg	Dominion
U1-093	4/29/2008	Ladysmith 230kV	190	0	Active	VA	2008 Q3	Oil	Carolina	Dominion
U1-094	4/29/2008	Ladysmith 230kV	190	0	Active	VA	2008 Q3	Oil	Carolina	Dominion
T78	10/5/2007	Arnolds Corner 34.5kV	10	9.9	Under Construction	VA	2008 Q4	Methane	King George	Dominion
U2-031	6/9/2009	Kings Fork 34.5kV	30	24.75	Active	VA	2008 Q4	Methane	Suffolk City	Dominion
S102	7/31/2007	Ladysmith 230kV	890	170	Under Construction	VA	2009 Q2	Natural Gas	Carolina	Dominion
T79	10/5/2007	Shacklefords 34.5kv	6	6.4	Under Construction	VA	2009 Q2	Methane	Gloucester	Dominion
U1-095	4/29/2008	Ladysmith 230kV	190	0	Active	VA	2009 Q2	Oil	Carolina	Dominion
U4-009	11/17/2008	Louisa 230kV	144	3	Active	VA	2009 Q2	Natural Gas	Orange	Dominion
U2-013	5/16/2008	Northeast 34.5kV	8	8	Active	VA	2009 Q4	Methane	Henrico	Dominion
S108	7/31/2007	North Anna 500kV	1080	20	Active	VA	2010 Q2	Nuclear	Louisa	Dominion
S109	7/31/2007	North Anna 500kV	20	20	Active	VA	2010 Q2	Nuclear	Louisa	Dominion
S110	7/31/2007	North Anna 500kV	1080	65	Active	VA	2010 Q2	Nuclear	Louisa	Dominion
S81	7/31/2007	Basin 230kV	277	45	Active	VA	2010 Q2	Natural Gas	City of Richmond	Dominion
S82	7/31/2007	Surry 230kV	90	20	Active	VA	2010 Q2	Natural Gas	Surry	Dominion
S83	7/31/2007	Surry 230kV	93	20	Active	VA	2010 Q2	Natural Gas	Surry	Dominion
S84	7/31/2007	Surry 230kV	93	20	Active	VA	2010 Q2	Natural Gas	Surry	Dominion
S85	7/31/2007	Surry 230kV	93	20	Active	VA	2010 Q2	Natural Gas	Surry	Dominion
S111	7/31/2007	Surry 500kV	950	15	Active	VA	2010 Q4	Nuclear	Surry	Dominion
S113	7/31/2007	Surry 230kV	950	15	Active	VA	2010 Q4	Nuclear	Surry	Dominion
S114	7/31/2007	Surry 230kV	950	75	Active	VA	2010 Q4	Nuclear	Surry	Dominion
S79	7/31/2007	Chesterfield 230kV	685	27	Active	VA	2010 Q4	Coal	Chesterfield	Dominion
P38	12/22/2005	Bremo 230kV	675	625	Under Construction	VA	2011 Q2	Natural Gas	Buckingham	Dominion
S115	7/31/2007	Surry 230kV	950	75	Active	VA	2011 Q2	Nuclear	Surry	Dominion
S80	7/31/2007	Chesterfield 230kV	349	20	Active	VA	2011 Q2	Coal	Chesterfield	Dominion

Queue	Queue Date	PJM Substation	Total MW	Incr MWC	Status	State	In Service	Fuel	County	Transmission Owner
U2-068	7/21/2008	Mount Storm-Valley 500kV	130	16.9	Active	VA	2011 Q4	Wind	Rockingham	Dominion
U4-026	12/19/2008	Lowmoor-Lexington 230kV	100	13	Active	VA	2011 Q4	Wind	Botetourt	Dominion
S112	7/31/2007	North Anna 500kV	1080	65	Active	VA	2012 Q2	Nuclear	Louisa	Dominion
S52	5/29/2007	Morrisville 500kV	600	600	Active	VA	2012 Q2	Natural Gas	Warren	Dominion
T180	1/31/2008	Gainesville 230kV	690	650	Active	VA	2012 Q2	Natural Gas	Prince William	Dominion
U3-016	9/4/2008	Midlothian 230kV	550	550	Active	VA	2012 Q2	Natural Gas	Goochland	Dominion
S97	7/31/2007	South Anna 230kV	144	20	In-Service	VA	2013 Q2	Natural Gas	Orange	Dominion
S98	7/31/2007	South Anna 230kV	144	20	In-Service	VA	2013 Q2	Natural Gas	Orange	Dominion
S99	7/31/2007	Possum Point 230kV	806	20	Active	VA	2013 Q2	Oil	Prince William	Dominion
T167	1/31/2008	Four Rivers 230kV	285	120	Active	VA	2013 Q2	Natural Gas	Hartford	Dominion
T168	1/31/2008	Four Rivers 500kV	1010	1010	Active	VA	2013 Q2	Natural Gas	Hartford	Dominion
P08	9/14/2005	Possum Point	600	600	Active	VA	2014 Q2	Natural Gas	Prince William	Dominion
T06	8/3/2007	Yorktown 230kV	838	20	Under Construction	VA	2014 Q2	Oil	York	Dominion
Q65	7/14/2006	North Anna 500kV	1594	1570	Under Construction	VA	2018 Q3	Nuclear	Louisa	Dominion

Table A5 provides a listing of the new generation facilities proposed for construction in Maryland and their CPCN status.

Table A5. New Generation Facilities Proposed for Construction in Maryland

Developer / Facility	Size (MW)	Location	Fuel	Case Number	Proposed In-Service Date	CPCN Status
Clipper Windpower, Inc.	101	Garett County	Wind	8938	Q4 2006 (Suspended	Granted 3/26/2003
Savage Mountain	40	Garett County	Wind	8939	3/20/2010 (Extension)	Granted 3/20/2003
Sempra Energy / Caotoctin	600	Fredrick County	Gas	8997	2009 (Docket Closed 77/28/2008)	Granted 4/25/2005
Synergics Wind Energy	40	Garett County	Wind	9008	2008 (Withdrawn 5/7/2008)	HE. Order 10/31/2006
Constellation / Gould Street (Refurb.)	101	Baltimore City	Gas	9124	Q2 2008	Granted 2/15/2008
Constellation / Calvert Cliffs	1640	Calvert County	Nuclear	9127	Q4 2015	In Progress
CPV Maryland, LLC / St Charles	645	Charles County	Gas	9129	Q4 2011	Granted 11/8/2008
Constellation / Riverside (React. Unit 5)	85	Baltimore County	Gas	9132	Q2 2010	Granted 5/10/2008

Table A6 and Table A7 illustrate how the DAM LMPs in the top demand 250 hours of the year 2008 differed in Vermont, New Hampshire, and unconstrained Western and Central Massachusetts.

Table A6. Price of Top Marginal Hours

Zone	50th	100th	150th	200th	250th
NH	$185.2	$168.5	$156.4	$147.4	$143.0
VT	$188.3	$171.4	$159.1	$150.7	$145.2
WCMass	$189.5	$170.3	$157.4	$150.0	$145.8

Table A7. Relative Price of Top Marginal Hours

Zone	50th	100th	150th	200th	250th
NH	98%	98%	98%	98%	98%
VT	100%	100%	100%	100%	100%
WCMass	101%	99%	99%	100%	100%