Exhibit RJS-4____

A Comprehensive Financial and Economic Assessment of Future Iowa Baseload Generation in a Carbon-Constrained Environment

Prepared for:

MidAmerican Energy Company

NERA
Economic Consulting

February 2013

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Table of Acronyms

- AEO: Annual Energy Outlook
- AFUDC: Allowance for Funds Used During Construction
- CAIR: Clean Air Interstate Rule
- CCS: Carbon Capture and Sequestration
- CDF: Cumulative Distribution Function
- COL: Combined Construction and Operating License
- CSAPR: Cross-State Air Pollution Rule
- DOE: U.S. Department of Energy
- ECP: Electricity Capacity Planning Model
- EFD: Electricity Fuels and Dispatch Model
- EFP: Electricity Finance and Planning Model
- EIA: Energy Information Administration
- EMM: Electricity Market Module
- EPA: U.S. Environmental Protection Agency
- EPC: Engineering, Procurement and Construction
- FOAK: First-of-a-Kind
- GHG: Greenhouse Gas
- GSP: Gross State Product
- HCl: Hydrogen Chloride
- LDSM: Load and Demand Side Management Model
- MACT: Maximum Achievable Control Technology
- MATS: Mercury and Air Toxics Standards
- MidAmerican: MidAmerican Energy Company
- MROW: Midwest Reliability Organization-West
- NEMS: National Energy Modeling System
- NEMS-MEC: Version of NEMS Model Used in Analysis
- NERA: NERA Economic Consulting
- NIT: Nova Inventory Transfer
- NRC: Nuclear Regulatory Commission
- NSPS: New Source Performance Standard
- O&M: Operating and Maintenance
- PI+: Policy Insights Plus
- PM: Particulate Matter
- RPS: Renewable Portfolio Standard
- S&L: Sargent & Lundy
- SCR: Selective Catalytic Reduction
- SMR: Small Modular Nuclear Reactor
- SNCR: Selective Non-Catalytic Reduction
- USGS: U.S. Geological Survey
- WACC: Weighted Average Cost of Capital

EXECUTIVE SUMMARY

In 2010, the Iowa legislature directed MidAmerican Energy Company ("MidAmerican") to "undertake analyses of and preparations for the possible construction of nuclear generating facilities in this state that would be beneficial in a carbon-constrained environment."[1] MidAmerican engaged NERA Economic Consulting ("NERA") through a request for proposal process to perform portions of this analysis, and this report addresses the financial portion of the legislature's directive by developing:

- Eight energy market scenarios,
- Natural gas price forecasts for each energy market scenario,
- The forecasted customer revenue requirements for natural gas combined cycle and nuclear small modular reactors ("SMR"), under each energy market scenario and baseload generation alternative,
- A risk/probability analysis for these energy market scenarios and alternatives, and
- An assessment of the Iowa economic development impacts of pursuing each of the two baseload generation deployments.

Based upon the findings of this report, NERA concludes:

1. A nuclear SMR deployment could be a cost-effective choice for MidAmerican's customers compared to a deployment of natural gas combined cycle over the anticipated 60-year life of a nuclear SMR facility.
2. Nuclear SMR deployment could result in considerably greater Iowa economic development benefits than natural gas combined cycle deployment based upon positive impacts on Iowa employment and Iowa gross state product ("GSP").

This conclusion is based upon NERA's independent analysis presented in this report with the major findings summarized in this Executive Summary.

Analytical Approach

To complete this assessment, NERA developed an analytical approach summarized as follows:

- NERA developed projections for eight specific U.S. **energy market scenarios** through 2080 based upon three primary drivers: 1) natural gas availability, 2) economic growth,

[1] House File 2399.

and 3) environmental and carbon policy, assigning a specific probability of occurrence to each of the eight energy market scenarios.

- Using a nationally-recognized forecasting model (National Energy Modeling System or "NEMS") developed by the Department of Energy's ("DOE") Energy Information Administration ("EIA"), NERA produced eight national and Iowa-specific **natural gas price projections,** adjusting for the conditions in each specific energy market scenario.

- Using the projections from the NEMS-MEC[2] model along with two different baseload generation deployment plans for MidAmerican (either natural gas combined cycle or nuclear SMR), NERA calculated **revenue requirement comparisons** over the period 2012 through 2080 for a gradual 2,400 MW (nominal) deployment of baseload natural gas and nuclear generation in Iowa between 2020 and 2033.

- NERA completed a comparison of the **economic development impacts** of the natural gas and nuclear deployment on Iowa jobs, GSP, and disposable personal income.

Energy Market Scenarios

NERA developed eight specific energy market scenarios based upon the combination of natural gas supply, economic growth, and environmental policy.

- NERA used two natural gas supply projections: one directly from the EIA assumptions from the Annual Energy Outlook ("AEO") 2011 Reference Case, and a second based upon a combination of EIA assumptions selected by NERA experts to reflect an alternative natural gas resource and recovery projection with comparable likelihood to that of the 2011 AEO Reference Case.

- For economic growth (and electricity demand growth), NERA utilized two values of GDP and electricity demand growth (electricity annual growth of 0.8% and 1.1% from 2012 through 2035) consistent with EIA's AEO 2011 Reference Case and High Economic Growth Case.

- NERA projected continued environmental constraints on greenhouse gases ("GHGs") and other emissions associated with coal-fired generation. This would result in a significant increase in coal unit retirements as shown in Figure 1 (these policies are not reflected in AEO 2011, which account for the significant differences).

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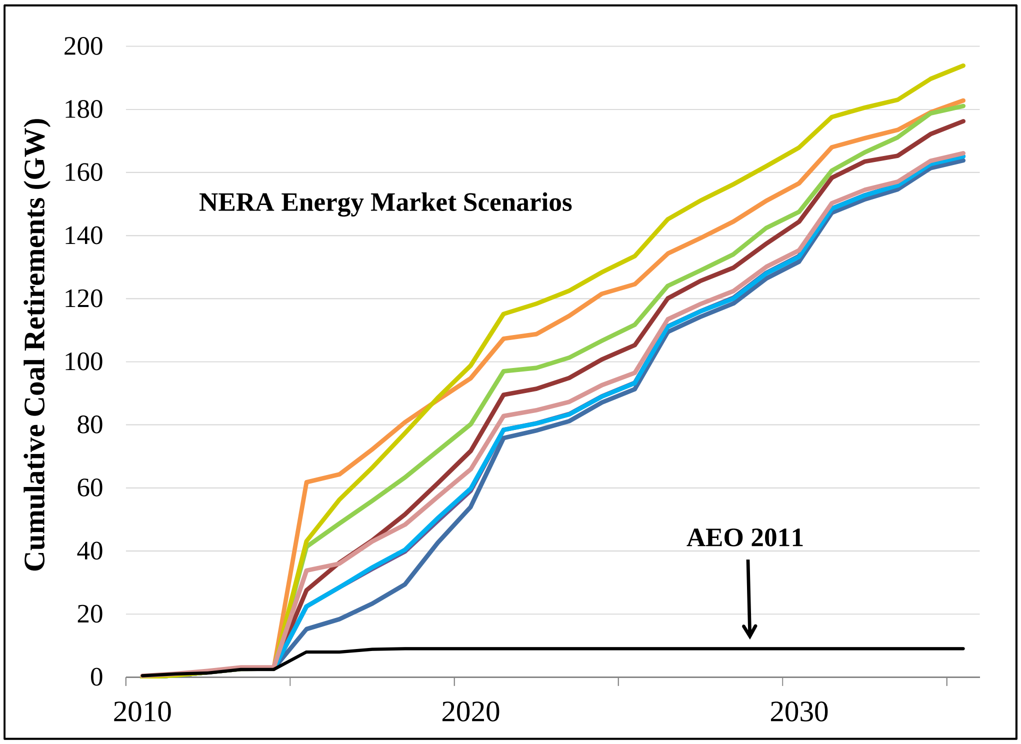
[2] The specific version of NEMS used for this analysis is referred to as NEMS-MEC to distinguish it from the version run by the EIA. The model is the same, but some assumptions have been modified to create the eight energy market scenarios. All modifications to the EIA assumptions are fully documented in this report.

Figure 1: Cumulative U.S. Coal Retirements (in GW) in Eight Energy Market Scenarios in this Analysis – Comparison with AEO 2011[3]



Natural Gas Price Projections

NERA developed a natural gas forecast for each of the eight energy market scenarios. The NERA forecast method used the integrated NEMS-MEC model through 2035, which assessed the energy needs across all U.S. energy consuming sectors. NERA then extrapolated these results through 2080 using NERA-developed techniques that considered changes in natural gas demand in both electric and non-electric sectors over time.

- The natural gas price projections for the eight energy market scenarios are shown in Figure 2.[4]
- The energy market scenario with high natural gas supply, low economic growth and a carbon price[5] results in the lowest natural gas price forecast through 2080 while the

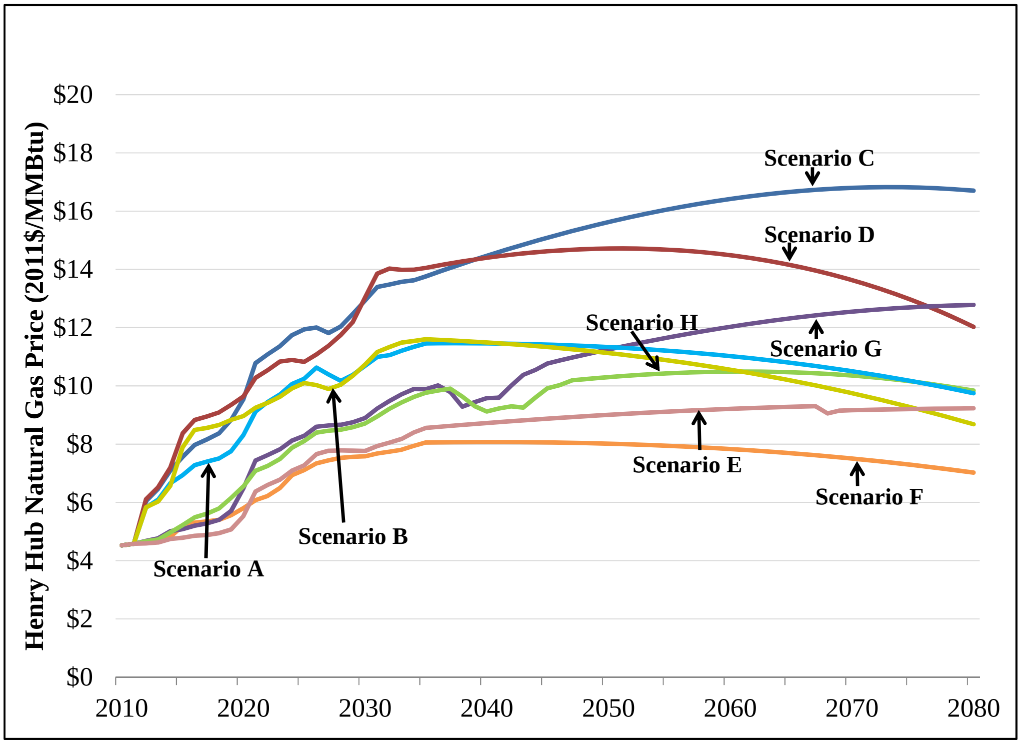
[3] The AEO 2011 Reference Case lists total U.S. coal capacity in 2011 as 315.0 GW in the electric power sector.

[4] While natural gas prices shown across the scenarios are different from market prices in the near term (*e.g.*, through 2015), those near-term prices have no impact on the following analysis, which is based on a long-term comparison of two deployment options over the period from 2020 through 2080.

[5] The carbon price is added at the point of emission and not included directly in the price of the fossil fuel.

energy market scenario with low natural gas supply, high economic growth and no carbon price provides the highest natural gas prices.

Figure 2: Henry Hub Natural Gas Price Projections through 2080 under Eight Energy Market Scenarios in this Analysis (2011$/MMBtu)



Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes

Revenue Requirement Comparisons

NERA calculated revenue requirements for each of the eight energy market scenarios assuming either a natural gas combined cycle or nuclear SMR deployment. The revenue requirements utilized information from the natural gas price projections along with natural gas combined cycle unit information (primarily from AEO 2011) and nuclear SMR information and revenue requirement models provided by MidAmerican and its consultant, Sargent and Lundy ("S&L"). NERA evaluated the results as differences in the present value of these revenue requirements through 2080.

The two primary drivers of differences in present value of revenue requirements are 1) the natural gas price projection, and 2) the engineering, procurement and construction ("EPC") contract price of the nuclear SMR generating unit deployment.

For each natural gas price projection, NERA determined a breakeven EPC contract price holding all other independent variables at their base values (Figure 3). The breakeven EPC cost for nuclear SMR ranges from a low of just over $3,000/kW to a high of almost $8,000/kW. SMR vendors have publicly released EPC prices estimates in the $4,000 to $5,000/kW range. However, no firm EPC contracts have been awarded for these SMRs. In addition, the first-of-a-kind ("FOAK") development costs could be significantly in excess of this price range while repetitive production could reduce costs for nth-of-a-kind units.

Figure 3: Breakeven EPC Capital Costs for SMR with Respect to Natural Gas Generation

Energy Market Scenario	Breakeven Nuclear SMR EPC Capital Cost ($/kWe)
A	$4,514
B	$6,118
C	$6,281
D	$7,702
E	$3,122
F	$4,326
G	$4,199
H	$5,527

Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes

The EPC contract price is a significant driver of the difference in present value revenue requirements. If the EPC contract price that will be offered at a future date were to be above the breakeven contract price in Figure 3, then MidAmerican would not enter into such a contract based only upon the economic analysis.[6] Both the future EPC contract price and the breakeven contract price will be known with greater precision when it is time to make the actual decision to

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6 MidAmerican (or any utility) may consider several additional factors when making a generation addition beyond economics such as: fuel diversity, public policy, reliability, economic development, *etc.*

commit resources to nuclear SMR or natural gas combined cycle capacity. Both will be determined in part by the best estimates of the future natural gas prices at the time that MidAmerican would need to be firmly deciding on building additional baseload capacity. The relatively short construction time for new natural gas combined cycle would allow MidAmerican ample time to deploy natural gas combined cycle (instead of nuclear SMR) if the EPC costs are found to be above the breakeven contract price at that decision point resulting in nuclear SMR deployment not being pursued.

NERA also evaluated several independent uncertainties (those uncertainties that are independent of other uncertainties). NERA identified three independent uncertainties as being most relevant:

- Nuclear delay - The nuclear delay sensitivity assumes a 2.5 year delay beginning in the second quarter of 2012. The 2.5 year delay (to the fourth quarter of 2014) in the nuclear deployment improves the present value of revenue requirements for the nuclear SMR deployment relative to the natural gas combined cycle deployment. This improvement is attributable to delaying the relatively high upfront capital costs associated with deploying nuclear. The relatively small magnitude of the improvement is due to the lower offsetting costs of replacement power purchases during the period of delay.[7] This indicates that deferring the decision for nuclear SMR or natural gas combined cycle deployment beyond the second quarter 2012 could be beneficial with respect to customer revenue requirements.

- Uranium fuel prices - While not subject to the same volatility observed in natural gas markets, there is uncertainty associated with available stocks of uranium in the global market. NERA developed two alternatives to its base uranium fuel price forecast – one with higher prices and one with lower prices.

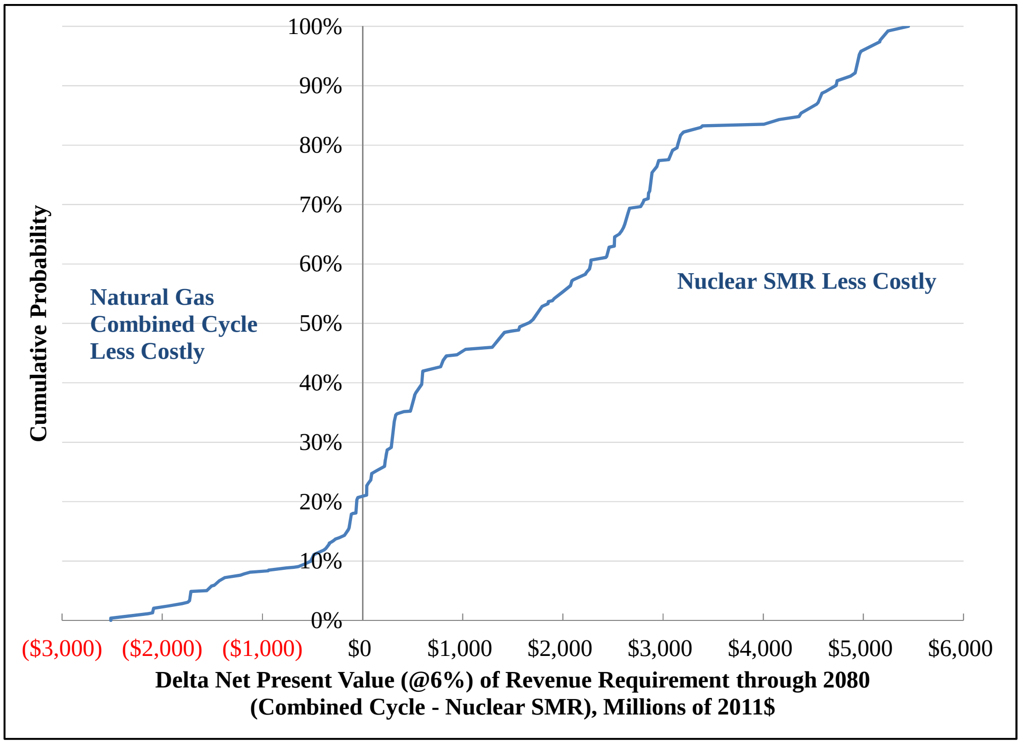
- Fixed operating and maintenance ("O&M")/labor costs - There is uncertainty regarding both the cost of labor and the quantity of labor (for both nuclear and natural gas combined cycle units), which jointly are reflected in labor costs. The fixed O&M/labor costs for the nuclear SMR units are significantly larger than those for the natural gas combined cycle generating units. NERA developed two alternatives to its base assumptions regarding fixed O&M/labor costs based on percentages of the base forecast. The higher alternative makes natural gas combined cycle have relatively lower revenue requirements than nuclear SMR because of nuclear SMR's higher share of fixed O&M/labor costs (and the reverse is also true).

Using the nuclear SMR cash flow and revenue requirements provided by MidAmerican and S&L, NERA developed a cumulative probability distribution function combining the uncertainties of the various natural gas price projections and the three significant independent

[7] While the nuclear delay results in lower present value costs on a probability weighted average basis, the nuclear delay results in higher present value costs in the scenarios with a carbon price.

variables. Comparing the deployment of 2,400 MW of incremental generation installed gradually from 2020 through 2033, the projected present value of revenue requirements through 2080 would be less for a nuclear SMR deployment relative to a natural gas combined cycle deployment approximately 80% of the time.

Figure 4: Difference in Net Present Value of 2012 through 2080 Revenue Requirements



Economic Development Impacts

NERA evaluated the Iowa economic development impacts for the nuclear SMR and natural gas combined cycle deployment options using the nationally recognized REMI Policy Insights Plus ("PI+") model. The REMI PI+ model includes as inputs the estimates of the types and locations of the cash flows associated with the alternative baseload generation deployments and the resulting revenue requirements impact on Iowa electricity and natural gas rates.

The deployments of nuclear SMR and natural gas combined cycle generation have fundamental differences in the timing and composition of costs over the lifetime of each asset (Figure 5 and Figure 6). This directly impacts economic development in Iowa. These differences include:

- Higher on-site employment at a nuclear SMR site,
- Lower fuel costs for a nuclear SMR deployment that results in lower payments to entities outside Iowa, and

- Differential Iowa electricity rates over the period through 2080 for the nuclear SMR and natural gas combined cycle deployments.

Figure 5: Annual Revenue Requirements for Nominal 2,400 Nuclear and Natural Gas Deployment for Scenario A, 2012-2080 (Low Natural Gas Supply, Low Economic Growth and No Carbon Price) (2011$ Millions)

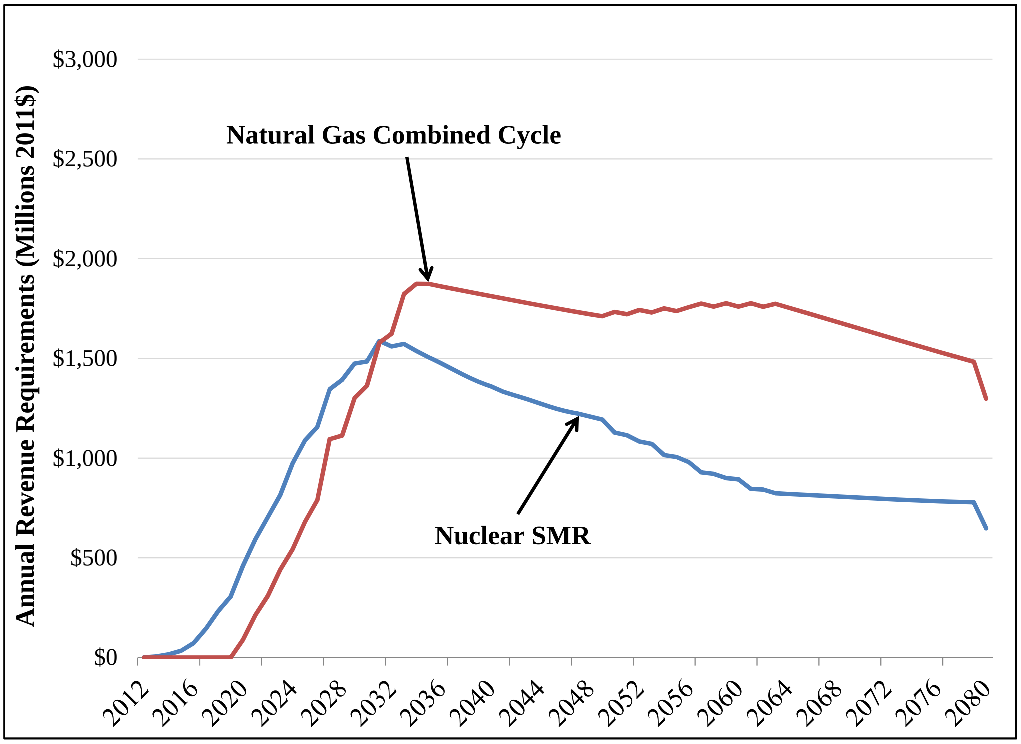
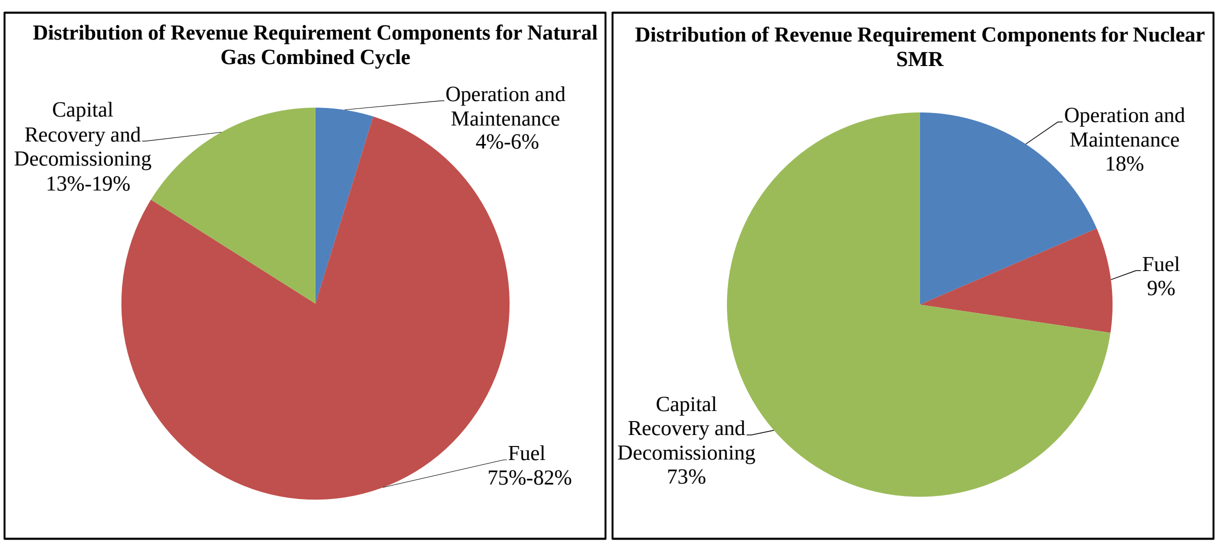


Figure 6: Average Component Shares of Present Value Revenue Requirement for Natural Gas Combined Cycle Generation and Nuclear SMR Generation, 2012-2080



- The economic development benefits to Iowa are more positive for a nuclear SMR deployment compared to a natural gas combined cycle generation deployment for each of the eight energy market scenarios, as shown in Figure 7.

- The present value of Iowa GSP through 2080 is estimated to be approximately $5 billion higher for a nuclear SMR deployment for the most likely energy market scenario (scenario A – low natural gas supply, low economic growth, no carbon price), with a range of increases in GSP across the eight energy market scenarios of $2.4 billion to $8.8 billion.

- The Iowa average annual employment is estimated to be 7,000 higher for a nuclear SMR deployment compared to a natural gas deployment for scenario A, with a range of increases in average annual employment across the eight energy market scenarios of 5,000 to 10,000.

- The present value of Iowa disposable personal income is $5 billion higher for a nuclear SMR deployment compared to a natural gas deployment for scenario A, with a range of increases in disposable personal income across the eight energy market scenarios of $3 billion to $7 billion.

Figure 7: Comparison of Difference in Macroeconomic Results through 2080: Nuclear SMR less Natural Gas Combined Cycle in Iowa (All dollar values in 2011$)

Scenario Characteristics				Macroeconomic Results		
Energy Market Scenario	**Average Henry Hub Price ($/MMBtu)**	**Average Electricity Demand Growth Rate**	**CO_2 Price in 2020 (2010$/ metric ton)**	**Present Value Increase in GSP (Millions$)**	**Average Annual Increase in Employment (Jobs)**	**Present Value Increase in Disposable Personal Income**
A	$10.77	0.4%	$0	$5,336	7,039	$4,922
B	$10.46	0.3%	$20	$8,786	9,932	$7,104
C	$14.97	1.2%	$0	$6,744	7,396	$5,775
D	$13.53	1.0%	$20	$8,435	8,365	$6,813
E	$8.64	0.5%	$0	$2,358	5,109	$3,055
F	$7.60	0.4%	$20	$4,584	6,657	$4,454
G	$11.08	1.1%	$0	$3,625	5,269	$3,813
H	$9.94	1.0%	$20	$5,705	6,778	$5,096

I. INTRODUCTION

The 2010 Iowa legislature directed MidAmerican to "undertake analyses of and preparations for the possible construction of nuclear generating facilities in this state that would be beneficial in a carbon-constrained environment."[8]

MidAmerican engaged NERA to assess the portion of this legislative request related to the following major areas:

- What U.S. energy market scenarios could emerge during the expected life of a nuclear SMR deployment in Iowa?
- What are the natural gas price projections for these U.S. energy market scenarios?
- Will nuclear SMR generation be a reasonable financial alternative to natural gas baseload generation in Iowa in a carbon-constrained environment?
- What are the economic development (*i.e.*, macroeconomic) differences to Iowa in deploying nuclear SMR compared to natural gas baseload generation?

To address these questions, NERA undertook an approach that can be summarized in six different steps.

- **Step 1** is the identification of dependent uncertainties and the assignment of probabilities for various U.S. energy market projections. NERA identified three dependent uncertainties for the potential U.S. energy market developments: natural gas supply, economic and electric growth, and environmental policy.
- **Step 2** includes the integrated modeling of these uncertain variables in the form of eight different energy market scenarios. This step was performed using a modified version of the NEMS model (renamed as NEMS-MEC to distinguish it from the EIA version) to project the integrated scenario outcomes through 2035. These results were then extrapolated through 2080. The key results included natural gas prices and electricity demand.
- **Step 3** involves the construction of cash flows and revenue requirements for the nuclear SMR deployment and the natural gas combined cycle deployment. The cash flow and revenue requirements calculations includes outputs from Step 2 along with detailed cost assumptions about deploying either nuclear SMR or natural gas combined cycle in Iowa.

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8 House File 2399, passed in May 2010.

- **Step 4** is the sensitivity analysis to identify independent uncertainties that also should be incorporated into a full uncertainty analysis. Eight independent uncertainties were evaluated and three were found to be significant and incorporated into the full uncertainty analysis.

- **Step 5** includes the risk analysis. Probabilities are assigned to each independent uncertainty (along with the dependent uncertainties) to form a cumulative distribution function of the differences in the present value of revenue requirements between deploying nuclear SMR and natural gas combined cycle.

- **Step 6** includes the economic development impact analysis for the state of Iowa. This economic development impact focuses on differences in gross state product, annual employment, and disposable personal income in Iowa depending on whether nuclear SMR or natural gas combined cycle is deployed in Iowa.

Section II of this report describes the process NERA completed in selecting the eight U.S. energy market scenarios.

Section III details the underlying assumptions and approach used in the analysis with most assumptions originating from the EIA's AEO 2011 or a MidAmerican provided nuclear business plan.

Section IV provides natural gas price projections for the eight potential U.S. energy market scenarios, which are combinations of the dependent uncertainties for natural gas supply, economic growth, and environmental policy. The eight energy market scenarios were modeled using EIA's NEMS modeling system through 2035 and then extrapolated by NERA through 2080 (the final year included in the financial analysis). NERA assigned each of the dependent uncertainties a probability such that the eight energy market scenarios taken together represent the full probability of all outcomes. Key results include natural gas prices, electricity demand, and CO_2 emissions.

Section V of this report details the present value analysis from 2012 through 2080 of the revenue requirements and cash flow requirements for a nominal 2,400 MW nuclear SMR or natural gas combined cycle deployment added incrementally between 2020 and 2033.[9] As part of this analysis, NERA evaluated uncertain variables to determine if the results were sensitive to the alternative values associated with their respective ranges of uncertainty. The variables found to be sensitive were then included with the modeled/extrapolated results of eight natural gas price forecasts to create a more expansive scenario tree encompassing 144 different combinations of

[9] The analysis is based upon nuclear SMR and natural gas combined cycle generation deployments that would be expected to produce the same amount of energy. Because nuclear generating units typically operate at a higher capacity factor, the nuclear SMR unit has a lower rated capacity in this analysis 2,160 MWe compared to a natural gas unit 2,400 MWe.

variable outcomes for which new deployments in Iowa of nuclear SMR and natural gas combined cycle were considered. Each combination has an associated probability (which adds up to 100% across all the branches of the scenario tree). The probabilities and the present value differences in revenue requirements for the nuclear SMR and natural gas combined cycle deployments form a cumulative distribution function ("CDF") that informs the relative financial merits of the two baseload generating options considered (nuclear SMR and natural gas combined cycle).

Section VI includes the Iowa economic development analysis, which utilizes the local cash flows (including direct project employment) and resulting electricity rates for the two generation deployments to construct relative economic development differences in Iowa associated with deploying new nuclear SMR or new natural gas combined cycle generating facilities.

The appendices to this report provide additional results from the analysis, the tools used, and some comparisons to other publicly-available analyses.

II. ENERGY MARKET SCENARIOS

The energy market scenarios are combinations of three key variables that have interrelated effects on each other and on other energy market outcomes. These are referred to as "dependent uncertainties" and are addressed in a simultaneous manner within an integrated modeling framework. Each variable has two alternative possible outcomes which are representative of a substantial portion of the overall probability distribution. The probability distributions were developed based on the subjective views of experts on the NERA team. The sensitivity and risk analyses in Section V expand the possible combinations of future potential outcomes to include additional variables that are important sources of uncertainty, but are not interdependent, and therefore are not required to be addressed in the integrated modeling applied to the first three variables.

A. Section Findings

- NERA identified three key dependent uncertainties that will most likely drive the development of potential future U.S. energy markets: 1) natural gas supply, 2) economic and electricity demand growth, and 3) environmental policy.

- From combinations of potential outcomes of these three key dependent uncertainties, NERA developed eight specific energy market scenarios, each with a specific probability of occurrence.

- For natural gas supply, NERA experts selected two projections as representative of the range of uncertainty. One is EIA's AEO 2011 Reference Case; the other is based on a combination of two alternative AEO 2011 assumptions reflecting more pessimistic potential outcomes for natural gas resource quantities and their recoverability.

- For economic and electricity demand growth, NERA experts selected two values as representative of the range of uncertainty. Consistent with EIA's AEO 2011 Reference Case and High Economic Growth Case, these two values are electricity demand annual growth of 0.8% per year and 1.1% per year from 2012 to 2035.[10]

- For environmental policy, NERA experts selected two policy outcomes representing the range of likely environmental policy. The first policy includes existing rules and regulations, but also includes a representation of a New Source Performance Standard ("NSPS") for GHGs from existing coal and fossil steam units. The second outcome includes the policies from the first, but also layers on a carbon emissions price beginning in 2020.

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[10] The actual electricity demand growth in each energy market scenario is different from these two values because of changes in electricity demand in response to factors such as natural gas supply and environmental policy.

B. Development of Key Dependent Uncertainties

NERA identified three key dependent uncertainties that form the basis for the construction of the energy market scenarios. These key dependent uncertainties are: 1) natural gas supply, 2) economic and electricity demand growth, and 3) environmental policy. In NERA's experts' professional experiences, these three uncertainties have the most significant impacts on projections of future energy market outcomes. NERA also considered technology improvement as a dependent uncertainty, but ultimately decided it was less important than the other three uncertainties. NERA also found that other uncertain variables could be effectively incorporated independently of the integrated modeling scenarios. These other "independent uncertainties" are discussed in Section V.E.

The EIA's AEO 2011 full set of assumptions were utilized unless NERA determined that an assumption was inconsistent with NERA's view of potential energy market developments. NERA documented all changes to the AEO 2011 assumptions.[11]

1. Natural Gas Markets

The assumption for low price/high supply of natural gas (hereafter "high supply") is based on the natural gas outlook in the EIA's AEO 2011 Reference Case.[12]

The high price/low supply of natural gas (hereafter "low supply") is based on a combination of natural gas assumptions in EIA's AEO 2011 Low Shale EUR (Expected Ultimate Recovery) and High OCS (Outer Continental Shelf) Cost Cases. The resulting lower supply estimate (associated with the Low Shale EUR) could result, for example, from faster rates of decline in natural gas production than expected in the Reference case, and/or considerably lower ultimate recovery rates than expected for wells in areas where shale formations have not yet been tested.[13] In addition,

> *…the High OCS Cost assumes that costs for exploration and development of offshore oil and natural gas resources are 30 percent higher than those in the Reference case. The higher cost assumption is not intended to be an estimate of the impact of any new regulatory or safety requirements, but is simply used to*

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11 At the time this work was begun, AEO 2011 and its back-up assumptions were the latest available. Since then, AEO 2012 results have been released. Some comparisons of results between AEO 2011 and 2012 are included in Appendix C.

12 The AEO 2011 Reference Case in its entirety is not a suitable energy market scenario because the EIA is limited to evaluating existing policies only. For example, AEO 2011 did not include the now existing Mercury and Air Toxics Standards ("MATS") Rule. Potential future policies such as those related to GHG are not included in the AEO 2011 Reference Case. The same is true of the other cases from which NERA culled natural gas assumptions, the Low EUR and High OCS Cost Cases.

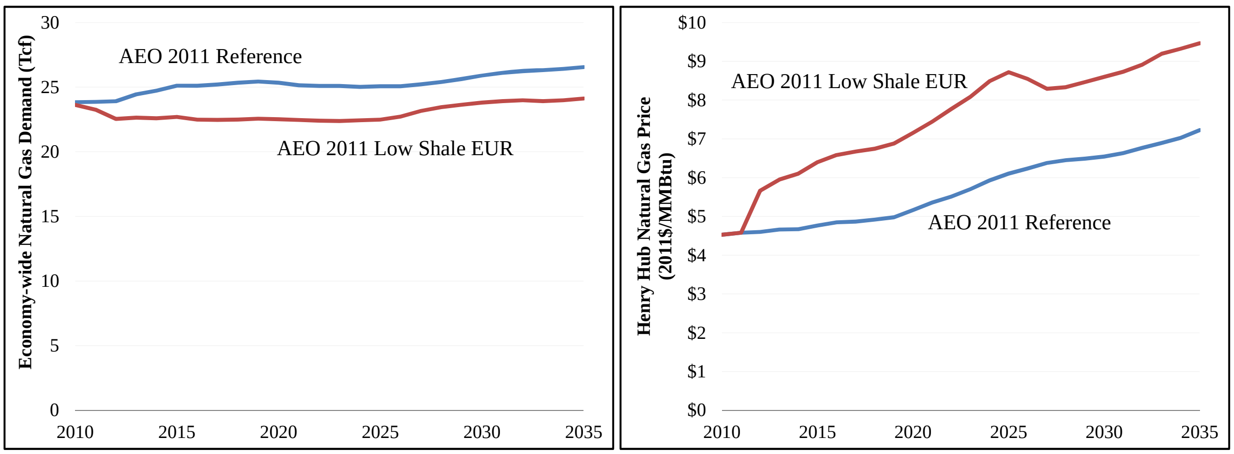
13 EIA, *The Annual Energy Outlook 2011 with Projections to 2035*, April 2011, DOE/EIA-0383(2011).

> *illustrate the potential impacts of higher costs on the production of OCS crude oil and natural gas resources.*[14]

Of these two sets of assumptions, the Low Shale EUR has the much greater impact on this case's projected natural gas prices, but both are combined for the final scenario.

Figure 8 shows the EIA economy-wide demand for natural gas and the associated prices at Henry Hub for the AEO 2011 Reference Case and the AEO 2011 Low Shale EUR Case (the demand and prices for the AEO 2011 High OCS Cost Case are left out of the figure since they are nearly identical to the AEO 2011 Reference Case).

Figure 8: Natural Gas Demand and Prices for AEO 2011 Reference Case and AEO 2011 Low Shale EUR Case



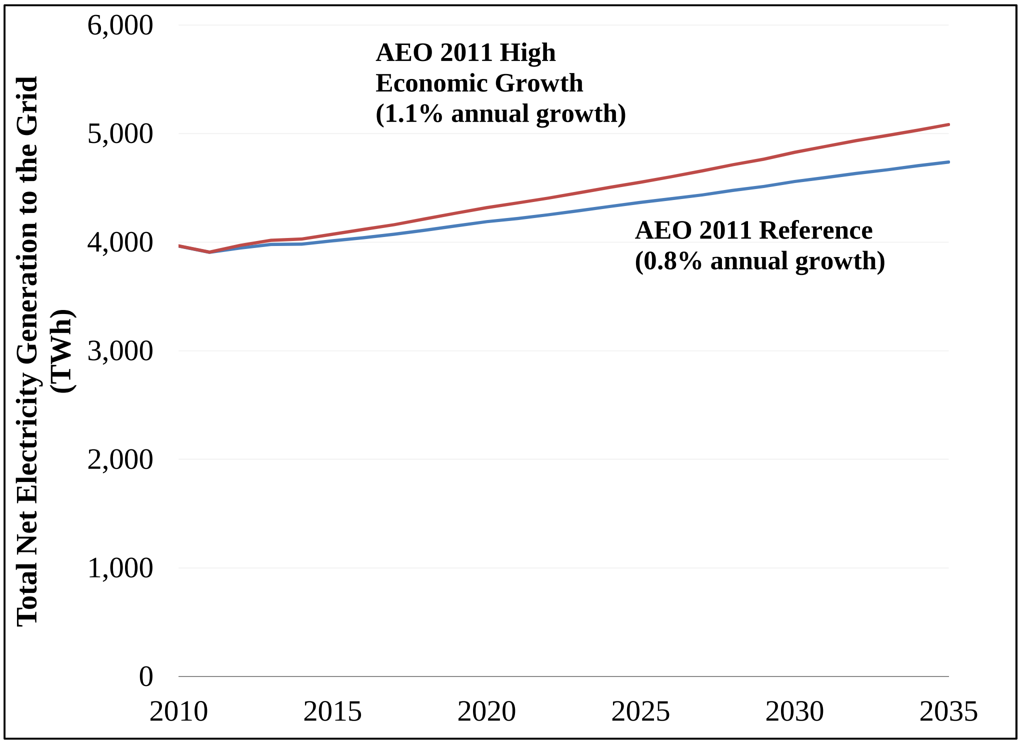
2. Economic and Electric Growth

Trends in economic growth have historically translated to similar trends of growth in electricity demand. NERA thus selected two economic growth scenarios: low growth and high growth as its starting point for developing a representation of the range of uncertainty for this topic.

The NERA low growth branches for the scenario tree are based on the EIA AEO 2011 Reference Case growth assumptions. The NERA high growth branches are based on the EIA's AEO 2011 High Economic Growth Case. Each case's respective electricity demand from AEO 2011 is included in Figure 9.

[14] *Ibid.*

Figure 9: Electricity Demand Growth in AEO Cases (2012-2035)



The AEO High Economic Growth Case includes two EIA modifications to the AEO Reference Case assumptions that lead to increased electricity demand. The EIA High Economic Growth Case assumes a faster rate of growth in (1) population and labor force and (2) productivity, yielding GDP growth of 3.2% per year from 2010 to 2035 compared to 2.7% in the EIA Reference Case.

NERA experts made two additional modifications to the EIA High Economic Growth Case to reflect possible outcomes of higher electricity demand beyond what might occur through higher economic growth alone. The residential and commercial demands for electricity are projected based on end-use demands in NEMS-MEC. For most end-uses, demand results from a projection of energy-using equipment and their efficiency levels. However, other sources of energy consumption in which specific equipment cannot be identified, or the equipment's individual consumption is relatively small (*e.g.*, small consumer electronics like smart phones), consume a significant amount of electricity. These miscellaneous uses have grown substantially, and while the AEO projects their continued growth, a great deal of uncertainty exists regarding future trends. For the NERA high growth scenario, NERA has assumed that the miscellaneous uses in the residential sector increase at an additional 2% per year above the EIA AEO 2011 amount, and in the commercial sector increase an additional 1.5% per year. Since miscellaneous uses of electricity demand in both the residential and commercial sectors represent a relatively small share of the total respective residential and commercial sector demands, the all-sector growth rate in electricity demand would be only slightly above the 1.1% annual growth rate from 2012 through 2035 from the AEO 2011 High Economic Growth Case.[15]

The other modification made to electricity demand by NERA is a reduction in the assumed short-term price elasticity. The short-term elasticity represents adjustments in consumer behavior in response to changes in energy prices. In the AEO 2011, EIA assumed this elasticity to be -0.30 for electricity and -0.15 for other fuels. For the NERA high growth assumption, the electricity elasticity was set equal to -0.15, the same as for other fuels, based on NERA's judgments to represent some of the uncertainty in consumer response to electricity price changes.

3. Environmental Policy

The most significant changes NERA made to the EIA AEO 2011 assumptions are with respect to environmental policy. The AEO 2011 only includes environmental policies in effect when the EIA modeling is conducted. In the case of AEO 2011, this was January 2011.[16] However, for a utility evaluating the investments considered in this report, including environmental policies expected to be in place during the operating life of the investment is more appropriate. Several environmental policy changes relevant to the electric sector have occurred in the past few years that are not reflected in the AEO 2011 Reference Case, and various carbon policy regulations are currently under consideration.

a. No Carbon Pricing

The No Carbon Pricing branches of the scenario tree contain the policies included in the AEO 2011 Reference Case assumptions, but replace the Clean Air Interstate Rule ("CAIR") with the Cross-State Air Pollution Rule ("CSAPR"). Additionally, NERA included the utility air toxics rule[17] and did not allow any new deployments of coal without carbon capture and sequestration ("CCS"). For carbon, there is no explicit price on those emissions for these No Carbon Pricing scenario tree branches. Instead, a representation of a NSPS for GHGs from existing coal and fossil steam units is implemented. This sets efficiency limits by state, which would result in significant retirements of these units from 2020 through 2035.[18]

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[15] This higher demand growth, inclusive of the higher growth in miscellaneous uses, is the starting point for the energy market scenarios that include High Growth, not the 1.1% growth included in Figure 9.

[16] EIA, *The Annual Energy Outlook 2011 with Projections to 2035*, April 2011, DOE/EIA-0383(2011), p. ii.

[17] The final utility air toxics rule, named the Mercury and Air Toxics Standards or "MATS" rule, was issued in December 2011, after NERA had commenced modeling. The final MATS rule did not differ significantly (for purposes of modeling assumptions) from the proposed rule that NERA had used.

[18] In March of 2012, the EPA released an NSPS for GHG emissions for new fossil electric generating units that effectively removes new coal-fired generation without CCS from being considered as an option. Many legal

b. Carbon Pricing

The Carbon Pricing branches on the scenario tree include the same environmental policies as the No Carbon Pricing branches (including the NSPS for GHGs from existing sources), but also layer on an economy-wide carbon emissions price that begins in 2020 at $20.27 per metric ton of CO_2 (in 2011 dollars).[19] This price increases at 5% per year in real dollars.[20] The carbon price, applied at the point of emission, increases the effective price of all fossil fuels in all sectors of the economy relative to their carbon content.

C. Constructing a Scenario Tree

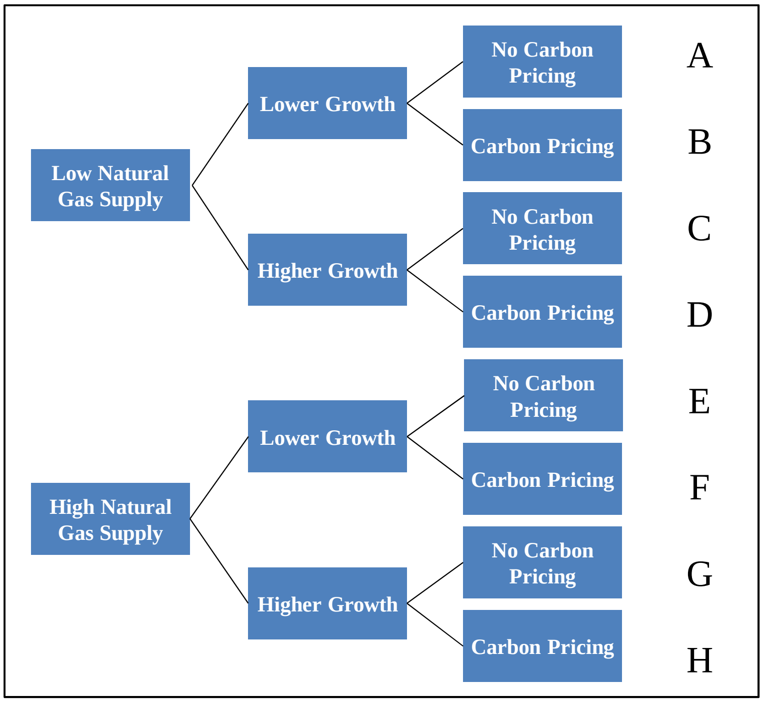
Combinations of the three dependent uncertainties form a scenario tree with eight branches. Figure 10 depicts the uncertainties included in each branch of the tree.

experts feel that this NSPS will trigger a requirement to set standards for existing fossil electric generating units, although the timing and stringency of such a standard is still unclear.

[19] Equivalent to $20 per metric ton of CO_2 emitted in 2010 dollars.

[20] The 5% annual increase (in real dollars) is based on an estimate of the social discount rate. In particular, 5% is a rate that has been used in many proposed carbon legislative proposals over the last decade, including the cost containment reserve price in the American Power Act of 2010 and the Technology Accelerator Payment in the Low Carbon Economy Act of 2007.

Figure 10: Scenario Tree



A verbal description of the future conditions which could lead to each of these eight energy market scenarios shown in Figure 10 is summarized below.

Scenario A – Low Natural Supply, Low Growth, No Carbon Pricing

The U.S. shale resource is not as large as the current optimistic supply outlook provided by the DOE. Higher drilling costs are attributable to increased regulation of shale drilling. A lower economic growth rate becomes the long-term norm. Little appetite for strict carbon legislation exists under these conditions, but current anticipated programs (CSAPR, MATS Rule, and NSPS for GHGs) move forward.

Scenario B – Low Natural Supply, Low Growth, Carbon Pricing

The shale resource is not as large as the current optimistic supply outlook provided by the DOE. Higher drilling costs are attributable to increased regulation of shale drilling. A lower economic growth rate becomes the long-term norm. Even with these conditions, sufficient public and political consensus exists to implement a policy that includes a price on CO_2.

Scenario C – Low Natural Supply, High Growth, No Carbon Pricing

The shale resource is not as large as the current optimistic supply outlook provided by the DOE. Higher drilling costs are attributable to increased regulation of shale drilling. The U.S. and global economies return to higher economic growth rates. New household technologies that use electricity continue to be introduced. Little appetite exists for strict carbon legislation, but current anticipated programs (CSAPR, MATS Rule, and NSPS for GHGs) move forward.

Scenario D – Low Natural Gas Supply, High Growth, Carbon Pricing

The shale resource is not as large as the current optimistic supply outlook provided by the DOE. Higher drilling costs are attributable to increased regulation of shale drilling. The U.S. and global economies return to higher economic growth rates. New household technologies that use electricity continue to be introduced. Sufficient public and political consensus exists to implement a policy that includes a price on CO_2.

Scenario E – High Natural Gas Supply, Low Growth, No Carbon Pricing

The current optimistic supply outlook for shale gas is realized, keeping natural gas prices relatively low. A lower economic growth rate becomes the long-term norm. No carbon pricing emerges since little to no growth in CO_2 emissions results from the relatively low natural gas prices paired with lower economic growth.

Scenario F – High Natural Gas Supply, Low Growth, Carbon Pricing

The current optimistic supply outlook for shale gas is realized, keeping natural gas prices relatively low. A lower economic growth rate becomes the long-term norm. The relatively low natural gas prices make it less costly to reduce CO_2 emissions, and a policy that would price CO_2 emissions is enacted.

Scenario G – High Natural Gas Supply, High Growth, No Carbon Pricing

The current optimistic supply outlook for shale gas is realized, keeping natural gas prices relatively low. The U.S. and global economies return to higher economic growth rates. New household technologies that use electricity continue to be introduced. Relatively low electricity prices limit consumer incentives for energy efficiency. Little appetite for strict carbon legislation exists, but currently anticipated programs (CSAPR, MATS Rule, and NSPS for GHGs) move forward.

Scenario H – High Natural Gas Supply, High Growth, Carbon Pricing

The current optimistic supply outlook for shale gas is realized, keeping natural gas prices relatively low. The U.S. and global economies return to higher economic growth rates. New household technologies that use electricity continue to be introduced. Sufficient public and political consensus exists to implement a policy that includes a price on CO_2.

D. Assigning Probability to Energy Market Scenarios

To produce a probabilistic assessment, NERA experts assigned probabilities to the respective potential outcomes of each of the key uncertain variables described above. In assigning the probabilities, each uncertainty was considered in isolation but the potential for the probabilities to be conditional was also explicitly considered.[21] NERA experts did not feel a need to assign probabilities conditionally for the natural gas supply or the economic growth uncertainties. The probabilities for the environmental constraint uncertainty were, however, defined as conditional on the state of both the natural gas and growth outcomes (*i.e.*, natural gas supply and economic growth rate may influence the political appetite for environmental constraints and hence the likelihood of more stringent policies).

A probability of 67% was assigned by NERA experts for a low natural gas supply (high natural gas price), and a 33% probability was assigned for a high natural gas supply (low natural gas price). The assignment of a higher probability on a lower natural gas supply was primarily driven by an August 2011 estimate of natural gas reserves from the U.S. Geological Survey ("USGS") for the Marcellus shale basin.[22] The USGS estimated reserves in Marcellus of 84 Tcf of technically-recoverable natural gas. This compared to 410 Tcf assumed in AEO 2011.[23] In total, in AEO 2011 EIA assumed that the total quantity of technically-recoverable shale gas in the U.S. was 827 Tcf, so reducing the Marcellus basin from 410 Tcf to 84 Tcf would have a significant impact on total estimates of shale resources in the U.S. EIA also announced in August 2011 that it would be adopting the new, lower estimate from the USGS.[24] Given this information, NERA's assignment of 67% probability to the lower natural gas supply outcome was based on a view that the AEO 2012 Reference Case supply assumption would be more consistent with that case. NERA's assignment of 33% probability on the higher natural gas supply case was based on an expectation that that case would be similar to the High EUR case supply of AEO 2012. These expectations of AEO 2012 projections were well-founded, as shown in Figure 11, which compares the estimated unproved technically-recoverable U.S. shale gas from AEO 2011 (the shale resource assumptions used in the NEMS-MEC model for the high natural gas supply case based on the AEO 2011 Reference Case) and AEO 2012.

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[21] A conditional probability arises when the probability of an event A depends on the outcome of another event B. For example, in such a case the probability of event A might be 50% if event B is true, but 70% if event B is false.

[22] See http://energy.usgs.gov/Miscellaneous/Articles/tabid/98/ID/102/Assessment-of-Undiscovered-Oil-and-Gas-Resources-of-the-Devonian-Marcellus-Shale-of-the-Appalachian-Basin-Province.aspx.

[23] See http://www.eia.gov/analysis/studies/usshalegas/.

[24] See http://www.bloomberg.com/news/2011-08-23/u-s-to-slash-marcellus-shale-gas-estimate-80-.html.

Figure 11: Total Unproved Technically-Recoverable Shale Resource from AEO 2011 and AEO 2012

	AEO 2011	AEO 2012
Reference Case[25]	827 Tcf	482 Tcf
Low EUR Case[26]	414 Tcf	241 Tcf
High EUR Case[27]	1,654 Tcf	964 Tcf

Equal probabilities were assigned to the outcomes in which the economy would be growing at the higher or lower rate. Economic growth is highly correlated with increased productivity and technological progress. Factors that could lead to higher growth include new technological breakthroughs and/or higher population growth; factors that could lead to lower growth include a slower-than-historical level of technological progress and/or lower population growth. The assignment of equal probabilities reflects the difficulty in accurately forecasting economic growth over the long term, as well as a view among NERA experts that there is no reason to expect either outcome to be relatively more likely.[28]

The probabilities for the environmental uncertainty were set as conditional probabilities. A combination of low natural gas supply and low economic growth would make the government less likely to enact an environmental policy that includes a price on carbon emissions (this would likely not impact regulations included in both the carbon pricing and no carbon pricing scenarios because these are regulatory requirements not subject to economic/political sentiments like legislation would be). Conversely, a combination of high natural gas supply and high economic growth would make an environmental policy including a price on carbon emissions more likely. In each case, the more likely outcome was assigned a 70% probability and the less likely outcome a 30% probability. In all other instances (*e.g.*, lower natural gas supply with higher growth or higher natural gas supply with lower growth), equal probability was deemed to be a reasonable expectation for environmental policy outcomes that include and do not include a price on carbon.

Figure 12 contains a summary of probabilities for each variable of the energy market scenarios. The total probability across the eight scenarios equals 100%. Since 100% of possible states are

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25 See Table 9.2 from "Assumptions to Annual Energy Outlook 2011" and "Assumptions to Annual Energy Outlook 2012."

26 Estimated based on case definition, which states "EUR per shale gas well is assumed to be 50% lower than in the Reference case."

27 Estimated based on case definition, which states "EUR per shale gas well is assumed to be 50% higher than in the Reference case."

28 It should be noted that the potential outcomes were first defined as a full continuum, and the two specific rates modeled in the analysis were selected to be representative of the expected value on each of two segments of that continuum after it was divided at the estimated median. Thus, it is not a coincidence that both values are assigned equal probability, but a choice by NERA to use two values that could be assigned equal probabilities.

included, this allows for a comparison of results across scenarios that can be easily understood through the use of CDFs, which are utilized in Section V.E.[29]

Figure 12: Summary Scenario Probabilities

Energy Market Scenario	Natural Gas Supply	Growth	Environmental	Pr (Gas)	Pr (Growth)	Pr (Enviro | Gas/Growth)	Total Probability
A	Low Gas Supply	Low	No Carbon Price	67%	50%	70%	23%
B	Low Gas Supply	Low	Carbon Price	67%	50%	30%	10%
C	Low Gas Supply	High	No Carbon Price	67%	50%	50%	17%
D	Low Gas Supply	High	Carbon Price	67%	50%	50%	17%
E	High Gas Supply	Low	No Carbon Price	33%	50%	50%	8%
F	High Gas Supply	Low	Carbon Price	33%	50%	50%	8%
G	High Gas Supply	High	No Carbon Price	33%	50%	30%	5%
H	High Gas Supply	High	Carbon Price	33%	50%	70%	12%

[29] This approach is considered superior to assessing a "base case," "best case" and "worst case," which provides little insight into the distribution of potential outcomes.

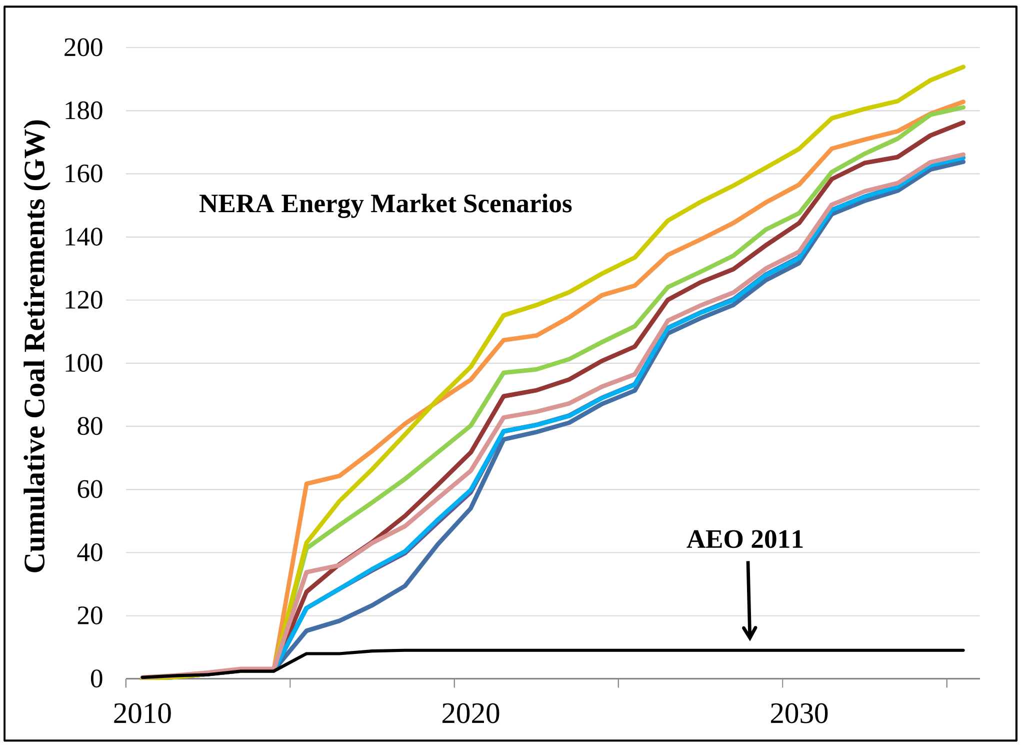
III. MODELING APPROACH AND ASSUMPTIONS

A. Section Findings

- Starting from a nationally-recognized forecasting model ("NEMS") developed by the DOE's EIA, NERA produced eight national and Iowa-specific natural gas price projections through 2035, adjusting for the conditions in each specific energy market scenario. [30]

- NERA documented all changes made to the AEO 2011 Reference Case assumptions. Significant changes were made to incorporate current expectations for environmental and GHG regulations likely to be implemented by the U.S. Environmental Protection Agency ("EPA"). These regulations would result in a significant increase in coal generation retirements in every one of the eight energy market scenarios, as shown in Figure 13.

Figure 13: Cumulative U.S. Coal Retirements (in GW) in the Eight Energy Market Scenarios in This Analysis – Comparison with AEO 2011



[30] The specific version of NEMS used for this analysis is referred to as NEMS-MEC to distinguish it from the version run by the EIA. The model is the same, but some assumptions have been modified to create the eight energy market scenarios. All modifications to the EIA assumptions are fully documented in this report.

For the revenue requirement and cash flow analyses, NERA relied upon the following major sources of information:

- Nuclear SMR unit deployment: a nuclear business plan developed by MidAmerican and S&L,
- Natural gas combined cycle unit deployment: EIA assumptions tailored to Iowa, refined to include balance of plant costs, and
- Firm natural gas pipeline transportation costs: derived for two major pipelines serving Iowa.

B. The NEMS-MEC Model is an Integrated Model

The NEMS-MEC model is an integrated model of the U.S. economy developed by making minor assumption adjustments to the DOE/EIA's NEMS model, which is used to produce the forecasts for the AEO. As an integrated model, it captures the relationships between energy consumption and energy prices throughout the U.S. economy (not just the electricity sector), providing a more accurate view of the business decisions faced by consumers of energy whether they are electricity generators, industrial manufacturers, or households. Since much of this analysis depends on the outlook of the natural gas market, capturing these interactions between energy use sectors is important to accurately assess the potential natural gas demands and prices.

An alternative non-integrated model might fail to capture the responses to higher prices such as home energy conservation efforts or fuel switching by electricity generators, industrial users, or transportation users. For example, within the electric sector there may be large scale fuel switching from coal to natural gas. However, the majority of natural gas is consumed outside the electric sector and natural gas demand and price relate directly to the supply of natural gas and the economy-wide demands. Failing to capture the responses of the non-electric sector could lead to a false conclusion about the relative demands and more importantly the prices in the natural gas market.

The NEMS-MEC model is a complex model (see Figure 84 in Appendix B) given all of the different economic interactions that are represented over time. Each scenario the NEMS-MEC model evaluates takes several days between model run time, results reviews, and post-processing of results. To manage costs, NERA did not evaluate every possible scenario using the model, but adopted the scenario tree approach described in Section II.

C. Summary of Key Modeling Assumptions

NERA developed energy price forecasts using a modified version of NEMS, which was used in producing the AEO 2011.[31] The version used in this analysis has been renamed as NEMS-MEC to distinguish it from the EIA version.

Figure 14 contains a high-level summary of key AEO 2011 assumptions and deviations from the EIA 2011 AEO assumptions (if any) that NERA made for this analysis. Additional information is provided in the paragraphs that follow.

Figure 14: High-Level Summary of Key Assumptions

Assumption	AEO 2011	Changes and Usage of AEO 2011
Natural gas shale resource	• AEO Low EUR (expected ultimate recovery): shale EUR 50% lower than in Reference[32] • AEO Reference Case	• Low natural gas supply scenarios use AEO Low EUR assumptions • High natural gas supply scenarios use AEO Reference Case assumptions
Natural gas offshore and Alaska assumptions	• AEO Higher Outer Continental Shelf (OCS) Costs: OCS costs increased 30%[33]	• Low natural gas supply scenarios use AEO Higher OCS Costs assumptions • High natural gas supply scenarios use AEO Reference Case assumptions • Trigger cost for completion of natural gas pipeline from Alaska increased from $6.34 to $8.18/Mcf (2011$)

[31] A complete set of model documentation and assumptions used in the AEO 2011 can be found on EIA's website. For NEMS model documentation, see http://www.eia.gov/analysis/model-documentation.cfm. The assumptions of the AEO 2011 can be found in http://www.eia.gov/forecasts/aeo/assumptions/index.cfm.

[32] Full description of AEO Low UER Case per AEO: "The estimated ultimately recovery per shale gas well is assumed to be 50% lower than in the Reference case. The lower EUR per well could be the result, for example, of 1) earlier than expected abandonment of the well (*e.g.*, low gas prices relative to high operating costs), 2) faster gas production decline rates than expected, and 3) considerably lower than expected EURs for wells in areas where the formation has not yet been tested."

[33] Full description of AEO High OCS Costs Case per AEO: "The cost of exploration and development of offshore oil and gas resources is highly uncertain. For this case, costs will be increased 30%. This increase is not an estimate of how much costs will change as a result of any new regulatory and safety requirement but is simply an assumption used to highlight the impact of higher costs on the production of OCS crude oil and natural gas resources."

Assumption	AEO 2011	Changes and Usage of AEO 2011
Energy efficiency and demand response	• AEO Reference Case: electricity demand grows by 0.8%/year from 2012-2035; real GDP grows by 2.7% from 2012-2035 • AEO High Economic Growth: electricity demand grows by 1.1%/year; real GDP grows by 3.2% from 2012-2035	• Low growth scenarios use AEO Reference Case assumptions • High growth scenarios use AEO High Economic Growth Case assumptions with minor modifications to miscellaneous uses in the Residential and Commercial sectors
Environmental	• Includes CAIR, existing state emission programs, and state renewable portfolio standards (“RPS”)	• Removes CAIR, adds representation of CSAPR,[34] MATS and representation of NSPS • Scenarios with carbon price include CO_2 price of $20.27/metric ton (in 2011$) starting in 2020 and increasing by 5% in real dollars each year
Unit retirements	• Based on economics	• Incremental retirements due to NSPS policy
Selection of new generating capacity	• Based on economics using AEO capital cost assumptions	• Additions of nominal 2,400 MW of either nuclear SMR or natural gas combined cycle in Iowa’s region
Electricity markets and reliability	• New deployments added to ensure reliability by meeting regional reserve requirements	• No change
Energy infrastructure	• New natural gas pipelines added if deemed necessary and economic	• For nominal 2,400 MW of natural gas additions, specific Iowa pipeline transportation costs were developed
Impacts on other sectors and fuel markets	• Integrated model so all changes in energy prices are seen by consumers and responded to based on economics	• No change

[34] In August 2012 (after all modeling for this project had been completed), the U.S. Court of Appeals for the D.C. Circuit vacated the CSAPR and allowed CAIR to continue.

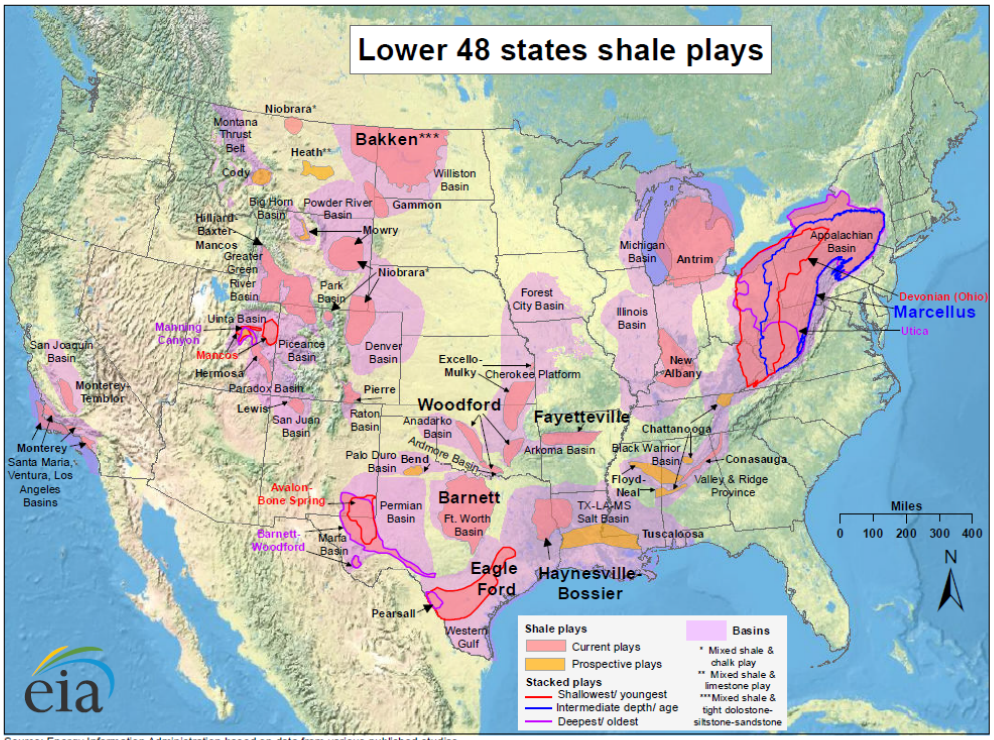
Assumption	AEO 2011	Changes and Usage of AEO 2011
Other changes from AEO 2011 included in this analysis		• Since AEO 2011 was released several small updates were made to NEMS (prior to the release of AEO 2012) • Treatment of interregional capacity transfers was modified so the transfer capacity is reflected in the supply/demand balance of importing regions • The location of a small set (roughly 5 GW) of existing power plants was updated

1. Natural Gas Supply and the Shale Gas Resource

a. Background

Over the last five years, the natural gas market in the United States has changed dramatically. Most of this change is due to technological breakthroughs in horizontal drilling and hydraulic fracturing that have unleashed a boom in the production of shale gas. Shale gas refers to natural gas that has been trapped in shale rock formations. The natural gas can be harvested by fracturing or "fracking" the rock formation, thereby releasing the previously trapped natural gas. Figure 15 shows the geographic distribution of the shale basins in the United States.

Figure 15: U.S. Shale Gas Map[35]



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Shale gas is viewed as a long-term game changer in the U.S. natural gas markets. However, many uncertainties have yet to be resolved. On the supply side, the estimates of technically recoverable shale gas are still quite uncertain, as highlighted by EIA in AEO 2011:

> *Estimates of technically recoverable shale gas resources are highly uncertain and change over time as new information is gained through drilling, production, and technology experimentation. Over the last decade, as more shale formations have gone into production, the estimate of technically recoverable shale gas resources has skyrocketed. However, these increases in technically recoverable shale gas resources embody many assumptions that might not prove to be true over the long-term and over the entire shale formation. For example, these shale gas resource estimates assume that gas production rates achieved in a limited portion of the formation are representative of the entire formation, even though neighboring shale gas well production rates can vary by as much as a factor of three. Moreover, the shale formation can vary significantly across the petroleum*

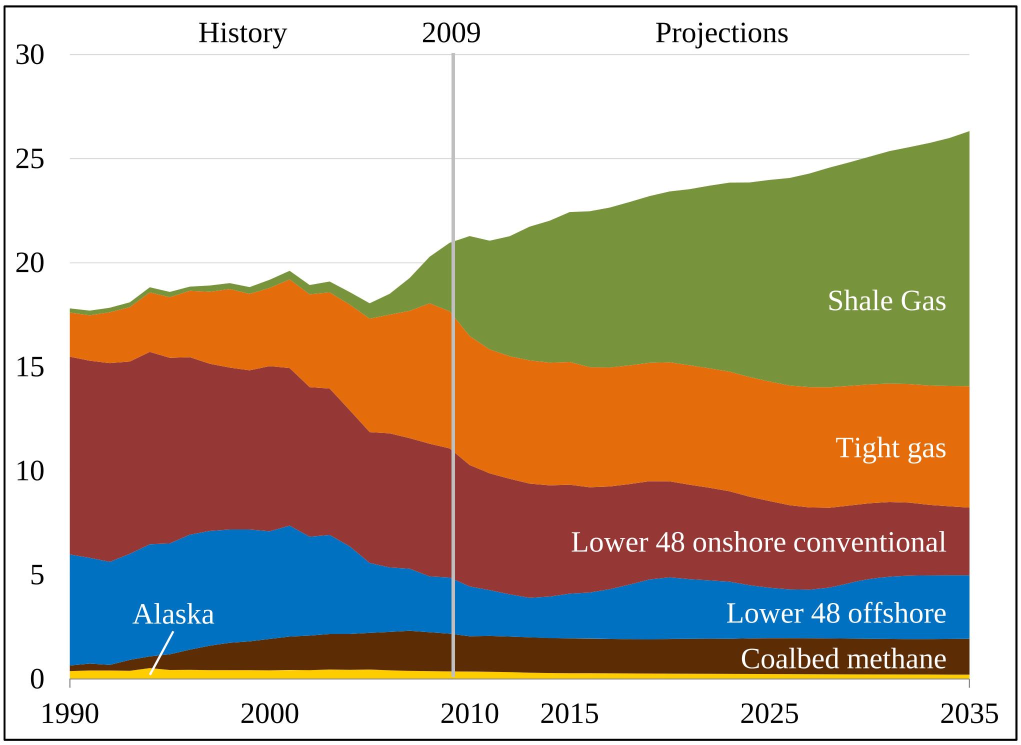
[35] Source: http://www.eia.gov/oil_gas/rpd/shale_gas.pdf.

basin with respect to depth, thickness, porosity, carbon content, pore pressure, clay content, thermal maturity, and water content.[36]

Other key uncertainties with respect to shale gas are related to the required water usage to extract the natural gas, disposal of wastewater and the potential for seismic events related to this disposal and the potential for state and/or Federal regulation of shale extraction.

Figure 16 shows the projected sources of U.S. natural gas production underlying AEO 2011's Reference Case. This shows declining production from more traditional sources and massive increases in shale gas, such that shale gas is expected to account for approximately one-half of U.S. natural gas production by 2035. The reliance on shale gas highlights the importance of the underlying supply assumptions for shale gas.

Figure 16: AEO 2011 Projection of Sources of U.S. Natural Gas Production, 1990-2035 (Trillion cubic feet per year)[37]



[36] See "Assumptions to the Annual Energy Outlook 2011," July 2011, p. 124.

[37] Recreated from AEO 2011 data, http://www.eia.gov/forecasts/archive/aeo11/excel/fig2.data.xls.

b. Changes to AEO 2011 Assumptions

The natural gas resources and extraction costs used by NERA in this analysis are consistent with the EIA AEO 2011 Reference Case except for assumptions regarding the construction of pipelines to move natural gas from Alaska or northern Canada to the lower 48 states. The AEO 2011 Reference Case assumes the cost of Alaska gas, to be compared to the lower 48 wellhead prices, is roughly $6.34 (2011 dollars per Mcf) based on the cost of extraction and pipeline financing. Once the wellhead price exceeds this trigger price for 1) two consecutive years, 2) on average over five previous years, and 3) for the expected average over the next three years, construction of the pipeline is assumed to start and be completed in four years. For the scenarios in this analysis, the trigger price was increased by NERA from $6.34 to roughly $8.18 (2011$) per Mcf.[38] The required price to sponsor a pipeline from the Mackenzie Delta was similarly increased. The higher trigger price means that at prices between $6.34 and $8.18, the NERA scenarios will have slightly less natural gas supply than would the AEO 2011 Reference Case. However, once prices meet the trigger conditions the supply is equivalent.

2. Electricity Demand, Energy Efficiency, and Demand-Side Management

All of the energy market scenarios include significant levels of energy efficiency and demand-side management. The AEO cases (and hence the NERA cases) include the American Recovery and Reinvestment Act of 2009, which provides funding for energy efficiency projects. This is represented in the NEMS-MEC model by increasing the price elasticity of demand for residential electricity.[39]

The increases in energy efficiency are directly reflected by forecasts of lower electricity demand growth rates (electricity demand as used in this report is equivalent to total electricity usage). The AEO 2011 Reference Case has an annual growth rate in electricity demand of 0.8% from 2012 through 2035; the AEO 2011 High Economic Growth Case has a growth rate of 1.1%.

The increased efficiency in the electric sector can be represented by looking at the ratio of electricity demand to GDP over time. Figure 17 shows this ratio graphically starting from 1949 and extending through 2035, the end of the NEMS-MEC modeling horizon.[40] The projected rate at which this ratio declines from 2012 through 2035 varies depending on the growth assumption of the particular scenario. The low growth scenarios exhibit a slightly higher rate of electric

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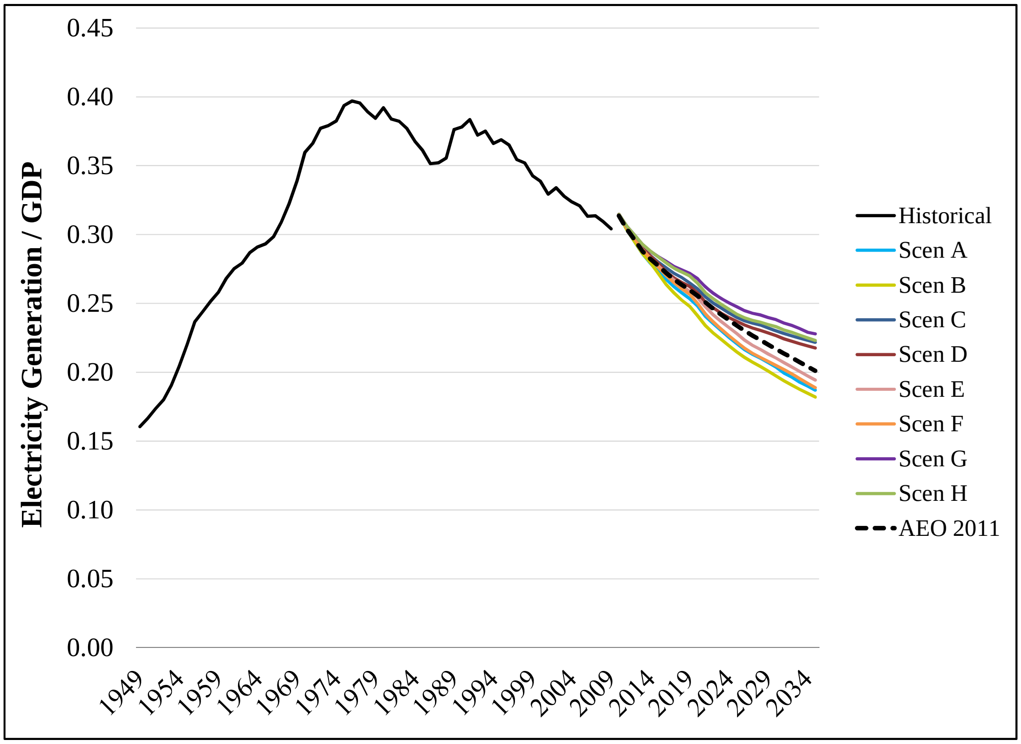
[38] The increase reflects a NERA belief that the costs of moving natural gas from Alaska to the continental U.S. would be higher than EIA has projected.

[39] See "Assumptions to the Annual Energy Outlook 2011," July 2011, p. 34.

[40] While NERA did extrapolate electricity generation through 2080, GDP was not extrapolated so this figure could not be extended beyond the 2035 end of the modeling horizon.

efficiency improvement than the high growth scenarios, but by 2035 all of the scenarios are at least 28% more efficient than they were in 2010.

Figure 17: Electricity Intensity – Historical and Projected for the Eight Energy Market Scenarios in this Analysis



Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes

3. Environmental

The AEO 2011 Reference Case reflects the CAIR implemented in 2009, state-implemented limits on mercury emissions and state RPSs. The EPA's CSAPR and the proposed MATS rule are not included in the AEO 2011 Reference Case but are included in the NEMS-MEC modeling. The CSAPR regulations modeled were finalized in July 2011 along with the proposed supplemental rule that includes six additional states in the seasonal NO_X program (that was finalized in December 2011 except for Kansas). Also included are the adjusted emission limits for nine states proposed by EPA in October 2011.[41]

To meet the NO_X emission limits, power plants can install a variety of combustion and post-combustion technologies. Post-combustion technologies include selective catalytic reduction ("SCR") and selective non-catalytic reduction ("SNCR"). These can be combined with combustion options such as low-NO_X burners to improve NO_X emission rates.

The model operates at a regional level, and for each region it computes the percentage of SO_2 emissions covered based on historical state emission levels in the region. Starting in 2012, the MATS rule includes variability limits that restrict the allowance of trading between states to meet the requirements. The NEMS-MEC model aggregately reflects the 18% variability limits for SO_2 by region but currently cannot represent variability limits for the two NO_X programs.[42]

Figure 18: Comparison of CSAPR and CAIR SO_2 and NO_X Regulations

Thousands of Short Tons	**Sulfur Dioxide**		**Annual NO_X**		**Ozone NO_X**	
	CSAPR	**CAIR**	**CSAPR**	**CAIR**	**CSAPR****	**CAIR**
Emission Limits (2012 – 2013)*	3,462	3,619	1,262	1,505	620	568
Emission Limits (2014 and beyond)*	2,216	2,533	1,181	1,254	584	485
Covered states (Lower 48 + DC)	23	24	23	26	26	26
** CSAPR was intended to replace CAIR once implemented, but it was vacated by the court.*						
*** Includes 6 states proposed in supplemental rule (IA, KS, MI, MO, OK, WI). Rule finalized in December 2011 includes 5 states, with Kansas status still pending.*						

The MATS rule limits emissions of mercury, acid gases, and other toxic pollution from power plants. It requires a 90% reduction in mercury emissions for existing coal and oil-fired plants, consistent with the maximum achievable control technology ("MACT"), within three years of

41 The MATS rule was finalized on December 21, 2011. The CSAPR, however, was vacated in mid-2012. Some form of replacement for CSAPR will almost certainly emerge over the long-term that this modeling effort is focused on. Thus, this analysis can be viewed as assuming that the CSAPR replacement will be similar in stringency to that of the vacated CSAPR rule. It is not one of the most important drivers of the analysis, however, because all eight of the energy market scenarios also assume some form of GHG limit on electricity generators, and those GHG limits render the CSAPR rule or its likely replacement largely irrelevant.

42 AEO 2011 allowed for variability limits for SO_2, but not NO_X, and adding such a constraint would have required significant effort.

the rulemaking (December 2014), although one-year extensions may be granted on a case-by-case basis (NERA's modeling did not include any extensions). The rule also requires emissions reductions from coal-fired plants of particulate matter ("PM") and hydrogen chloride ("HCl," a toxic acid gas). Although the NEMS-MEC model does not explicitly track emissions of PM and HCl, it captures this rule's effects by requiring fabric filters and scrubbers on all coal plants by 2015.

NEMS-MEC also includes assumptions regarding the EPA's future regulation of carbon dioxide emissions under the Clean Air Act as part of NSPS for GHG emissions from existing sources. NSPS was expected to be released in late 2011 or early 2012 but was not released at the time NERA's modeling was completed.[43] The NEMS-MEC model represents NERA's view of a potential NSPS as an efficiency standard that coal-fired generators must meet based on the weighted average heat rate for plants burning the same type of coal (bituminous, sub-bituminous, lignite coal, or steam oil/gas units). This approach is consistent with the Clean Air Act as well as the economics of least-cost dispatch because units exhibiting more expensive production costs (*i.e.*, less efficient) would retire before similar less expensive units.

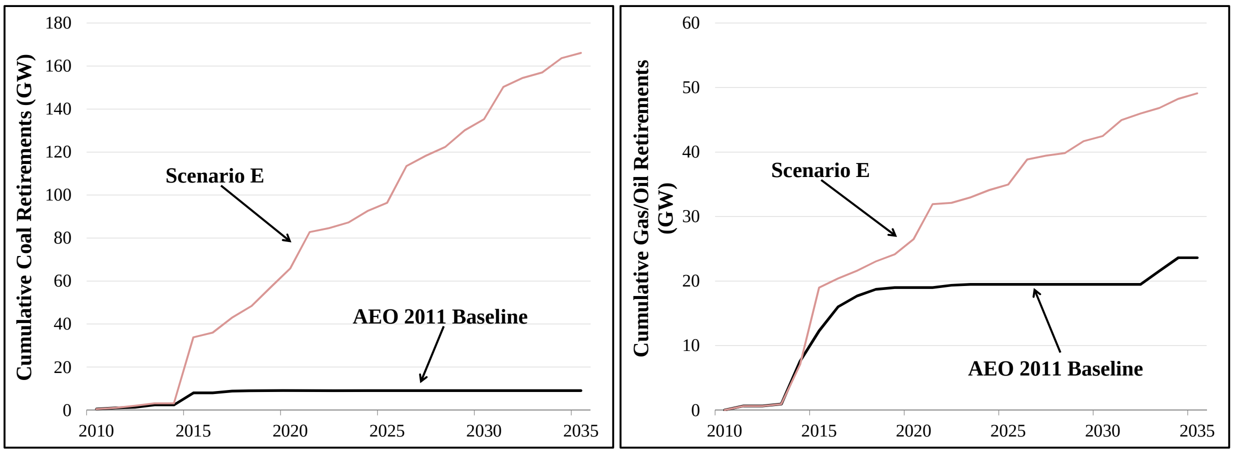
In 2020, the NERA-envisioned NSPS dictates a 2% improvement from the weighted average heat rate of the same fuel type and state in 2012. This standard tightens by an additional 1% every five years. NEMS-MEC exogenously implements this rule's impact by setting retirement years for generating units that did not meet the heat rate standards. The retirement years are phased in starting in 2016 rather than assumed to occur only every five years as the standards tighten. In addition, no new coal-fired power plants can be constructed unless they use CCS to sequester their CO_2 output. Figure 19 summarizes the cumulative quantities of retirements attributable to NSPS across all of the scenarios. Figure 20 demonstrates the significant increase in retirements in one energy market scenario (scenario E) compared to those in AEO 2011.

[43] In March 2012, an NSPS for GHG from new electric generating sources was released that effectively eliminates new coal-fired generators from being built unless they are equipped with CCS. No timing has been announced concerning when to expect an NSPS for GHG for existing electric generating sources, nor has EPA released any details of such a policy.

Figure 19: Cumulative Retirements Due to NSPS (GW)

	Coal	Steam Oil/Gas
2020	46	7
2025	87	15
2030	128	22
2035	161	29

Figure 20: Cumulative U.S. Coal/Steam Oil/Gas Retirements (in GW) – Comparison with AEO 2011



Some of the energy market scenarios include an explicit price on carbon emissions throughout all sectors of the U.S. economy, in addition to the NSPS. These carbon price scenarios represent legislation consistent with a variety of federal Bills over the last decade to significantly reduce U.S. carbon emissions over the long term. The NERA carbon price begins in 2020 at $20.27 per metric ton of CO_2 (in 2011$)[44] at the point of emission and increases at a real rate of 5% per year. This rate of increase represents an estimate of the social discount rate and has been used in many of the past policy proposals. The carbon price could be representative of a cap-and-trade policy or a carbon tax, because the specific form of implementation of such market-based policies would not affect the way it is incorporated into this analysis.[45]

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44 The 2020 price was initially set at $20.00 per metric ton, but in 2010$.

45 The form of the policy might be relevant if the government enacts carbon emission allowance allocations. A sensitivity analysis by NERA includes such allocations, but these would likely be phased out relatively early in the life of the new combined cycle units.

4. Unit Retirements

As in NEMS, generating unit retirements are a function of each unit's economics in the NEMS-MEC model. Generating units that cannot cover their fixed operating costs through energy market and/or capacity revenues are retired based on their economics. Retirements based on age or non-economic factors are not included in NEMS-MEC, with the exception of retirements added exogenously to comply with the assumed NSPS GHG regulations.

5. Selection of New Generating Capacity

In general, NEMS-MEC adds new U.S. generating capacity based on the relative economics of new capacity options using EIA assumptions. New capacity may be added to meet reserve margins or if the addition of such capacity would result in lower present value electricity costs over the life of an asset.[46] The new U.S. capacity options available include fossil fuel generators (natural gas combined cycle, natural gas combustion turbine, coal with CCS, and natural gas combined cycle with CCS) and non-fossil fuel generators (large scale nuclear, biomass, geothermal, municipal solid waste/landfill gas, hydropower, onshore and offshore wind, solar thermal, solar photovoltaic, fuel cells, and distributed generation). The costs for these technologies are consistent with AEO 2011.[47]

The only deviation from the AEO assumptions on the choice for new generating capacity was the forced additions of either natural gas combined cycle plants or nuclear SMR plants built in Iowa's electricity market region, starting in 2020 and continuing through 2033 for a nominal total of 2,400 MW, as shown in Figure 21.

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[46] Electricity costs include all costs associated with a resource including capital, fixed O&M, variable O&M, fuel, and emissions costs.

[47] NERA considered changing the costs of natural gas combined cycles and wind, but a sensitivity analysis showed no noticeable difference in model results so the AEO 2011 assumptions were maintained for all technologies.

Figure 21: Timing of Scenario Forced Additions of Capacity in Iowa's Region

Online Date	Nominal MW
October 1, 2020	300
October 1, 2022	300
October 1, 2024	300
October 1, 2026	300
April 1, 2027	300
April 1, 2029	300
April 1, 2031	300
April 1, 2033	300
Total	2,400

Actual capacity additions and timing would be based upon customer needs, market conditions, and factors that are specifically reviewed as part of the Iowa regulatory approval process. This schedule is an indicative schedule of potential additions in Iowa for purposes of comparing two baseload options, but the actual schedule and/or quantity could be different. Such a change, however, would not affect the conclusions from this analysis. The same is true if MidAmerican's ownership share of these capacity additions were to be less than 100%.

6. Electricity Markets and Interregional Transmission and Reliability

The Electricity Market Module ("EMM") within the NEMS-MEC model includes firm power and capacity trades across regions. It also models economic flows of electricity across regions based on differences in marginal costs. Existing and planned transmission capacity limit power flows. In addition, AEO 2011 includes an option to expand interregional transmission capacity rather than siting new capacity in another region.[48]

The NEMS-MEC model calculates reserve margins based on an iterative approach whereby the marginal cost of new capacity converges with the marginal cost of unserved electricity demand. Each region's reserve margin is set at this convergence point each year. In the AEO 2011 Reference Case the annual reserve margins range from 8% to 20%.[49]

The interregional transmission and reliability assumptions and/or methodology are consistent with AEO 2011.

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[48] Information based upon "Assumptions to the Annual Energy Outlook 2011," July 2011, p. 102.

[49] Information based upon "Assumptions to the Annual Energy Outlook 2011," July 2011, p. 100.

7. Natural Gas Infrastructure

The Natural Gas Transmission and Distribution Module within the NEMS-MEC model includes a representation of the existing interstate pipeline and storage system (and any announced expansions). If natural gas price and demand for natural gas increase, then pipelines and/or storage expand. Over time, revenue requirements recover capital costs associated with any pipeline expansions.[50]

No changes were made to the AEO 2011 assumptions and/or methodology with respect to interregional transmission and reliability.

8. Impacts on Other Energy Sectors and Fuel Markets

As represented in the NEMS-MEC model, actions in one sector of the economy ripple through the rest of the economy and produce a single integrated outcome. Consumers demand less electricity if electric prices increase, and natural gas prices will increase as the electric sector moves away from coal fueled generation and towards natural gas generation.

D. Producing Results from the NEMS-MEC Model

Based on the specified assumptions and all other assumptions maintained from AEO 2011, a specialized NERA contractor (OnLocation) executed the NEMS-MEC model to produce results for all eight energy market scenarios (scenarios A through H) assuming a deployment of natural gas combined cycles in Iowa. In addition, five scenarios (scenarios C, D, F, G, and H) were evaluated in which nuclear SMR was built in Iowa instead of natural gas combined cycles. To limit the expense of model input development and execution, these five scenarios were considered adequate to assess the impact on the U.S. natural gas price forecast in adding 2,400 MW of nuclear SMR compared to natural generation in Iowa. The demand for natural gas from 2,400 MW of capacity additions in Iowa is small compared to the total U.S. demand for natural gas, thus the differences between energy market scenarios with deployment of nuclear SMR as opposed to deployment of natural gas combined cycle are quite small.

The outputs from each scenario evaluated in the NEMS-MEC model are nearly identical to the outputs available from EIA for each AEO 2011 scenario they evaluated. These NEMS-MEC results then formed the base for the remainder of the analysis (described more fully in Section IV).

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[50] Information based upon "Assumptions to the Annual Energy Outlook 2011," July 2011, p. 130.

E. Model Assumptions for Revenue Requirement and Cash Flow Analysis

1. Nuclear SMR -Specific Assumptions

For nuclear SMR generation additions in the U.S., the NEMS-MEC model utilizes the AEO 2011 capital and operating cost assumptions for advanced nuclear deployments. For the nominal 2,400 MW nuclear SMR additions in Iowa, the cash flow and revenue requirements analyses, the detailed costs, and the spending schedule were developed in the MidAmerican business plan by S&L and provided to NERA. The one exception was the uranium fuel forecast, which NERA developed.

MidAmerican's nuclear business plan was used for the Iowa nuclear deployment capital costs. These costs were provided by MidAmerican in the form of their nuclear business plan, which included EPC contract estimates integrated with on-site owner's costs not included in the EPC contract. The nuclear business plan also included operation and maintenance costs for SMR-specific staffing plans and historical non-labor costs experienced at existing operating nuclear facilities.

2. New Natural Gas Combined Cycle Assumptions

For U.S. generating capacity additions, the NEMS-MEC model utilized the AEO 2011 capital and operating cost assumptions.[51] NERA utilized more refined assumptions for capital to include some balance of plant costs in addition to the overnight capital costs to arrive at the capital costs that are utilized in the nominal 2,400 MW nuclear additions in Iowa. The steps are summarized below:

- Started with AEO 2011 total overnight capital cost of $967/kW (in 2009$);
- Added owner's contingency costs of 12.5% of total overnight capital cost;
- Added natural gas pipeline lateral costs of 1.1% of total overnight capital cost;[52]
- Applied the EPA IPM Model Regional Multiplier for the MRO Region (region in which Iowa is located) of 1.004;[53]

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[51] Actual EPC contracts for a new combined cycle unit may be higher or lower at any specific point in time, but these costs are considered to be representative for the period through 2035.

[52] Percentages for owner's contingency costs, transmission interconnection costs and natural gas pipeline lateral costs are from "Cost of New Energy Combined Cycle Power Plant Updated Revenue Requirements for PJM Interconnection, LLC," August 26, 2008.

- Scaled up costs from 2009$ to 2011$ by multiplying by 1.022 per AEO 2011.

The resultant total overnight capital cost number (in 2011$) as well as other operating assumptions for new natural gas fueled combined cycle generation can be seen in Figure 22.

Figure 22: New Natural Gas Fueled Combined Cycle Assumptions (in 2011$ unless otherwise specified)

Category	Assumption
Overnight Capital Cost	$1,128/kW
Variable O&M[54]	$3.44/MWh
Fixed O&M[55]	$14.54/kW-year
Heat Rate, New (2010) [56]	7,050 Btu/kWh
Heat Rate, nth-of-a-kind (2035) [57]	6,800 Btu/kWh

For the cash flow analysis, NERA also needed to distribute the capital spending to attribute it to the proper year. The following spending schedule was assumed:

- Online Year minus 3: 10%;
- Online Year minus 2: 60%; and
- Online Year minus 1: 30%.[58]

3. Delivered Cost of Natural Gas to Iowa Location

The cost of natural gas that would be burned by a new baseload natural gas combined cycle unit in Iowa is a function of the commodity cost of natural gas and the transportation costs. For a base load natural gas deployment operating at an 81% capacity factor, the pipeline capacity was

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[53] IPM Model Documentation, Table 4-15.

[54] AEO 2011, Table 8.2, with a conversion to 2011$.

[55] AEO 2011, Table 8.2, with a conversion to 2011$.

[56] AEO 2011, Table 8.2.

[57] AEO 2011, Table 8.2. The nth-of-a-kind heat rate is 6,800 Btu/kWh, which is assumed to be available in the final AEO 2011 model year of 2035. NERA assumes a constant compound rate of improvement between 2010 and 2035, such that a new combined cycle unit built in 2020 has a heat rate of 6,949 Btu/kWh.

[58] "Cost and Performance Baseline for Fossil Energy Plants Volume 1," Revision 2, DOE/NETL Nov. 2010, Exhibit 2-18.

considered to be firm and not interruptible. NERA evaluated two potential routes to calculate the transportation costs. The first route assumes natural gas originates from supply points in West Texas and is delivered via the Northern Natural Gas Pipeline. The second route assumes natural gas originates from Alberta, Canada and is delivered via the TransCanada Alberta Pipeline System, Foothills Pipeline, and the Northern Border Pipeline.

To arrive at the expected transportation costs, NERA collected information on the three components of pipeline transportation costs: (1) the reservation rate, (2) the commodity rate, and (3) the fuel rate. In general, the reservation rate accounts for the fixed cost of reserving the necessary capacity for the pipeline while the commodity and fuel rates account for the variable costs associated with moving specific volumes of natural gas.

a. Northern Natural Gas Pipeline Deliveries

<u>West Texas to Iowa</u>

For the following transportation cost calculations along Northern Natural Gas Pipeline, NERA assumed that MidAmerican would transport natural gas from West Texas to Iowa.

The Northern Natural Gas pipeline system is composed of two sections: (1) a field collection area which includes West Texas and (2) a market delivery area which interconnects with several interstate pipelines. Reservation rates are distinct to each section.

Natural gas purchased in West Texas would flow across the Northern Natural Gas field area to the field/market demarcation point and continue on to the Northern Natural Gas market area, which includes Iowa. Capacity must be reserved on both sections (field area and market area) of the Northern Natural Gas Pipeline in order to move gas on a firm basis from West Texas to Iowa.

Natural gas can also be purchased in the Northern Natural Gas market area at either the field/market demarcation point or at one of the other interstate pipeline interconnections with Northern Natural Gas, such as from Northern Border Pipeline at Ventura, Iowa. In the case of natural gas being purchased from one of the interstate pipeline interconnections, capacity need only be reserved on the Northern Natural Gas market area section in order to move gas on a firm basis from these points to MidAmerican's service territory.

<u>Rates</u>

To calculate the firm reservation rate for the Northern Natural field area, NERA calculated the weighted-average of the pipeline's summer and winter field-to-market TFF rates; as of the Sixth Revised Volume No. 1 of the FERC Gas Tariff, Third Revised Sheet No. 51.[59] To calculate the reservation rate for the Northern Natural market area, NERA calculated the weighted-average of

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[59] Hereafter all references to sheets of Northern Natural Gas's FERC Gas Tariff refer to the version cited here.

the summer and winter market-to-market TFX rates as given on tariff Sheet No. 51. NERA then added an infrastructure fee onto this reservation rate to account for the costs of building a new mainline, branchline, lateral line, and compression and town border station equipment to the Iowa natural gas deployment site.

Adding the two (field and market area) annual reservation rates results in a total annual reservation rate for firm delivery of $380.91/MMBtu per year, or $1.0436/MMBtu per day. Since capacity must be reserved on both sections (field area and market area) of pipeline to move gas on a firm basis from West Texas to Iowa, these costs represent the total reservation costs for this transportation path.

Commodity rates and fuel rates also apply to both the field area and market area. Fuel rates are seasonal for summer and winter and are adjusted prior to the start of each season.

b. TransCanada Alberta System, Foothills, and Northern Border Pipelines

<u>Alberta, Canada to Ventura, Iowa</u>

For the following calculations, NERA assumed that MidAmerican would be moving natural gas from the AECO Hub/Nova Inventory Transfer ("NIT") Point in Alberta, Canada, to Ventura, Iowa. Natural gas would be purchased at the AECO Hub/NIT Point on the TransCanada Alberta System (also known as NOVA Gas Transmission), and would flow to the Foothills Pipeline at McNeill on the Alberta/Saskatchewan border. The gas would then flow through Foothills into the Northern Border Pipeline at the Canadian/United States border at Monchy, Saskatchewan/ Port of Morgan, Montana. The gas would then flow through the Northern Border Pipeline to Ventura, Iowa.

<u>TransCanada Alberta System</u>

To calculate the reservation rate for the TransCanada Alberta System, NERA retrieved from TransCanada's website the FT-D reservation rate for Group 1 delivery points, which include Foothills at McNeill. The daily reservation rate equates to U.S.$0.1851/MMBtu per day. There is no commodity rate or fuel on the TransCanada Alberta System.

<u>Foothills Pipeline</u>

To calculate the reservation rate for the Foothills Pipeline, NERA obtained the FT monthly demand rate for Zones 9 and multiplied this value by the specific transport distance, currency exchange rate, conversion factors, and the number of days in an average month to convert it into a daily reservation rate of U.S. $0.0819/MMBtu/day. There is no commodity rate for Foothills. The fuel rate on Foothills varies by month, and the April 2012 fuel estimate is 1.1%.

Northern Border Pipeline

To calculate the reservation rate for the Northern Border Pipeline, NERA used the maximum daily reservation tariff rate for T-1 and T-1B service from Port of Morgan, Montana to Ventura, Iowa, and distance to obtain the reservation rate on Northern Border at $0.3420/MMBtu per day. As with the Northern Natural Pipeline, NERA added an infrastructure fee to this reservation rate to take into account the costs of a new interconnect, hot tap, meter station, valving, piping, and a lateral line to the Iowa natural gas deployment location. These cost estimates are from the Northern Border Pipeline Company and amount to $0.1771/MMBtu per day. The final combined reservation rate comes out as $0.5191/MMBtu per day. NERA then added the commodity rate and fuel rates from Northern Border.

Total Costs

To calculate the reservation rate of the combined route (TransCanada Alberta System, Foothills, and Northern Border), NERA added together the three pipelines' individual reservation rates. The combined reservation rates total $286.91/MMBtu/year, which equates to $0.7861/MMBtu/day. Northern Border is the only pipeline in the route to have a commodity rate. Fuel is not charged or retained by TransCanada Alberta, but is retained by both Foothills and Northern Border; this combined charge is 3.0%.

c. Combined Average Delivery Costs

Given two possible paths and the fact that a final site for the potential natural gas combined cycle plant has not yet been selected, NERA utilized the average delivery costs for the two potential routes.

Reservation Rates

To calculate the reservation charges for each of the two pipeline routes, NERA multiplied each route's total reservation rate by an estimate of the maximum daily reservation capacity in MMBtu for the Iowa natural gas unit deployment. NERA estimated this maximum daily reservation capacity in MMBtu by multiplying the capacity of natural gas combined cycle online by an estimate of the weighted average heat rate for that same capacity (an estimate of the maximum daily MMBtu that would be required).

Commodity Charges

NERA calculated the commodity charges for Northern Natural and Northern Border (since the TransCanada Alberta System and the Foothills Pipeline have no commodity charges) by multiplying the commodity rate by the Annual Deliveries in MMBtu. NERA calculated the Annual Deliveries in MMBtu by multiplying the annual generation at the Iowa natural gas unit deployment by the weighted average heat rate for the natural gas combined cycle capacity.

Fuel Charge and Natural Gas Cost

NERA calculated the fuel charge and the cost of the natural gas together. Fuel is retained by Northern Natural, Foothills, and Northern Border, but is not retained by the Alberta TransCanada System.

For the Northern Natural route NERA applied a combined fuel retention percentage based on the combined route, as follows:

Gas + Fuel Cost =

[(Gas Price) / (1 – Fuel Rate)] x Annual MMBtu Deliveries

For Alberta TransCanada System/Foothills/Northern Border route:

Gas + Fuel Cost =

[(Gas Price + Fuel Costs per MMBtu on Foothills) / (1 – Fuel Rate on Northern Border)] x Annual MMBtu Deliveries, where:

Fuel Costs per MMBtu on Foothills =

[(Gas Price) / (1 – Fuel Rate on Foothills)] – Gas Price

The origin points and pricing on the two different routes were: (1) the Northern Natural Gas supply from the West Texas market area based on a West Texas Wellhead price from the NEMS-MEC model, and (2) the Henry Hub price from the NEMS-MEC model less a $0.35/MMBtu basis differential to AECO Hub/NIT in Alberta for the TransCanada Alberta System/Foothills/Northern Border route.

Total Costs

To obtain the total firm natural gas pipeline transportation costs for all deliveries to the Iowa combined cycle deployment site, NERA then summed the individual components of cost to arrive at the total cost for each pipeline route. To calculate the total transportation and natural gas cost, NERA averaged the total costs for each of the two routes. These are the annual costs for the delivered natural gas that are utilized in the cash flow and revenue requirement analyses, as well as in the sensitivity and risk analyses (discussed in more detail in the following sections).

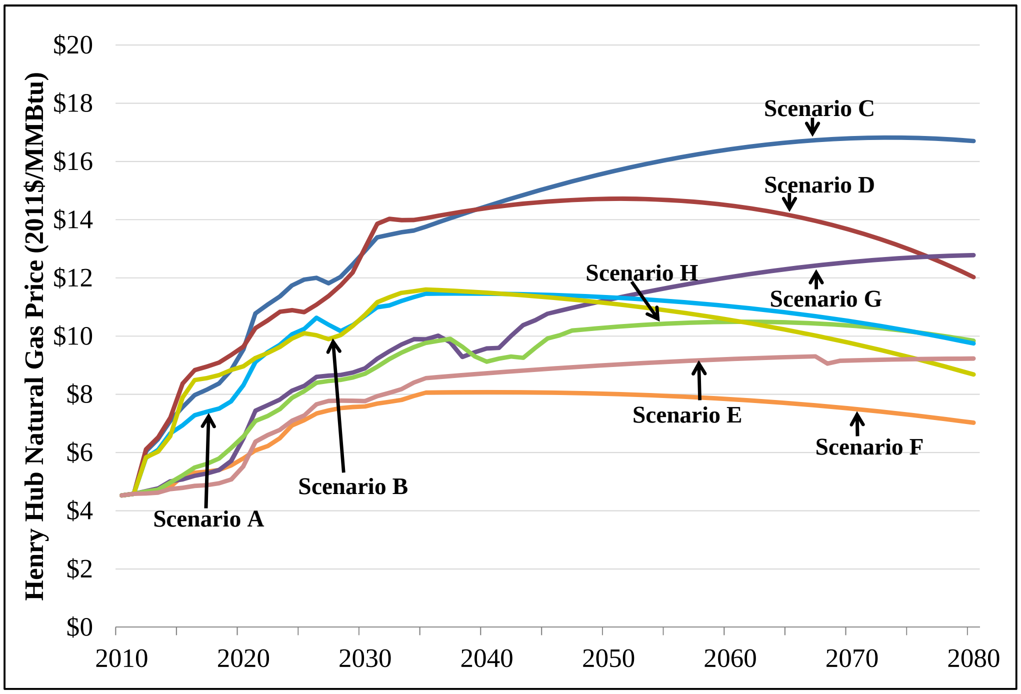
IV. NATURAL GAS FORECASTS AND OTHER KEY RESULTS FOR ENERGY MARKET SCENARIOS

A. Section Findings

- The NEMS-MEC model provided forecasts for natural gas prices, electricity demand, electricity rates, and CO_2 emissions for each of the eight energy market scenarios through 2035. NERA then developed specific extrapolation techniques to extend these eight forecasts from 2035 through 2080.

- The natural gas forecasts for the eight associated energy market scenarios are shown in Figure 23.

Figure 23: Henry Hub Natural Gas Price Projections through 2080 (2011$/MMBtu)



Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes

B. Approach

The NEMS-MEC model produced outputs for each of the energy market scenarios through 2035 and these outputs were extrapolated through 2080. The resulting natural gas price forecasts then became the starting point for the remainder of the analysis in this report, including the development of cash flows and revenue requirements, which were ultimately used in the macroeconomic analysis.

C. Long-Term Forecasting and Current Markets

This analysis compares two generation deployment options from 2012 through 2080. While the analysis begins in 2012, the natural gas forecasts in years 2012 through 2019 have no impact on the results since there are no differences in fuel consumed depending on the new generation deployment in those years. Thus, natural gas price results for 2012 through 2019 also have no consequence on the relative merits of a nuclear or natural gas combined cycle unit. Further, these differences do not imply that one set of prices is "right" and another is "wrong"; or that one or more of the energy market scenarios can no longer be expected to materialize over the study period.

The scenarios that have been developed include a series of assumptions about natural gas supply, economic growth, and environmental regulations which will likely have significant implications on fuel prices and demand, particularly beyond 2020. This is the focus of the study and where the results are most pertinent.

D. Types of Results from Modeling

The NEMS-MEC model produced results for each energy market scenario. Annual results from NEMS-MEC were produced through 2035. The direct NEMS-MEC results that NERA utilized were:

- Delivered retail electricity rates in the Midwest Reliability Organization-West ("MROW") region (the region in which Iowa is located) – used in calculating the costs of replacement power (when needed);
- Annual electricity demand in the U.S. – used to project MidAmerican's load going forward from 2012;
- Wellhead natural gas prices in the Southwest Supply Region (includes West Texas) – used in the delivered cost of natural gas along Northern Natural pipeline; and
- Henry Hub natural gas prices – used in the delivered cost of natural gas from Alberta after including a location basis.

In addition, several other results were used to extrapolate results from 2035 through 2080:

- Non-power sector natural gas demand;
- Power sector natural gas demand; and
- Electricity generation by fuel – power sector only.

The usage of each of these results is described below.

E. Extrapolation of Model Results through 2080

Since the NEMS-MEC model only projects results through the year 2035, further extrapolation was required in order to evaluate natural gas prices and electricity demand out to 2080 as required to conduct the desired revenue requirement and cash flow analysis for the generating unit deployment analysis.

Projection: Total Electricity Generation

The basis of this extrapolation was a projection of total electricity generation requirements from 2036 through 2080. The assumptions for this element of projection were a) a base growth rate of total electricity generation equal to the geometric mean growth rate over the five-year period from 2030 to 2035, and b) a growth rate modifier to account for assumed increases in energy efficiency during this same time period. NERA used a growth rate multiplier of 0.99, meaning that the base growth rate would decrease by 1% each year starting in 2036. This resulted in a profile of total electricity generation increasing year over year but increasing at a declining rate each year to reflect expected increases in energy efficiency over time.

Projection: Generation by Fuel Source

NERA projected electricity generation by fuel source for the 2036 to 2080 time period. These projected fuel sources were natural gas, coal, renewables, nuclear, petroleum, and other. A method of projection similar to that used for total electricity generation was used for each of these components. The definitions of these sources are the same as the definitions used by EIA in the AEO 2011.

Coal generation projections for each of the eight energy market scenarios were held constant at 2035 levels through 2080. The rationale for this is that loss of generation from the retirements of coal-fired generating units would be made up by generation from new deployments with CCS that may occur in the future, or increases in generation from other existing coal-fired generating units. NERA based this assumption on the current difficulty in constructing new coal-fired generation (without CCS) given the barriers in place and the unlikeliness of the relaxation of these barriers in the foreseeable future.[60]

Renewable generation was extrapolated in the same manner for all scenarios. This involved an assumption of an annual, year-over-year growth rate in renewable generation equivalent to the geometric mean growth rate over the five-year period from 2030 to 2035. Not surprisingly, the carbon price scenarios exhibited higher growth rates from 2030 to 2035, resulting in a higher share of renewable generation in these scenarios.

Nuclear generation projections for the four no carbon price scenarios assumed an annual, year-over-year growth equal to the geometric mean growth rate over the 20-year period from 2015 to 2035. For the four carbon price scenarios NERA used the geometric mean growth rate over only the 10-year period from 2025 to 2035 (this coincides with the timing of when significant quantities of new nuclear generation were being added), which resulted in a higher rate of growth and an increased share of nuclear generation going forward; as would be expected in a carbon priced energy market.

Petroleum generation and other generation were small in the NEMS-MEC projections and were assumed to remain constant at their 2035 level throughout the projections to 2080. The minimal contributions of these sources of generation as well as the marginal likelihood of new construction of these types justifies holding their current levels constant.

Projected natural gas generation from 2036 through 2080 was calculated as a residual component equal to the projected total electricity generation in any given year less the projected generation from all other sources. As such, no direct assumptions on the growth of natural gas generation were required and the residual was a result of assumptions on other aspects of the total generation mix.

Power Sector Natural Gas Consumption

Given the generation mix, NERA next converted the natural gas generation into power sector consumption for natural gas. This conversion was completed by calculating the implied average heat rates for natural gas-fired generation from the model runs up through 2035, based on annual power sector natural gas consumption and annual natural gas generation.[61] These average heat rates were then used for the implied average heat rates through 2080. NERA calculated a ratio of the implied average heat rate for natural gas generation relative to the estimated heat rate for a

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[60] Since the modeling was conducted, the EPA released a draft NSPS for GHG from new fossil electric generators that would preclude new coal-fired generators from being built unless they were equipped with CCS.

[61] Average heat rates for natural gas-fired generation reflect a mix of different vintages of natural gas combined cycle, combustion turbine, and other natural gas steam generators each with a different efficiency and heat rate. Summing up the natural gas consumption in the power sector and dividing it by the generation from these different types of natural gas-fired generators yields the implied average heat rate.

new natural gas combined cycle unit in each year, as provided from AEO 2011. NERA examined the change (improvement) in this ratio over the 2010 through 2035 and linearly projected the ratio out to 2080. Similarly, NERA calculated the improvement in the AEO-provided best achievable heat rate for new combined cycle plants over the 2010 through 2035 period and held that rate of improvement constant in order to project best achievable heat rates through to 2080. By combining the projected best achievable heat rates with the projected heat rate ratios, NERA determined power sector wide annual average heat rates for natural gas generation over the entire 2035 to 2080 period.

With calculated projections of natural gas generation as well as average heat rates for natural gas generation in the power sector through 2080, NERA was then able to derive projected power sector natural gas consumption. This calculation involved multiplying the projected natural gas generation and projected average heat rate in every year from 2036 through 2080 as well as the appropriate factors for translating units.

Non-Power Sector Natural Gas Consumption

The other component of natural gas demand that NERA derived involved the non-power sector natural gas consumption. The non-power sector natural gas consumption projection was developed by extrapolating trends in the growth of consumption exhibited during the 2010 through 2035 model run period out to 2080. In the lower growth energy market scenarios (scenarios A, B, E and F), this extrapolation was performed by applying the rate of growth in non-power sector natural gas consumption from 2034 to 2035 to each subsequent year, with an additional modifier of 0.99 to slow down this rate of growth over time to reflect increasing energy efficiency. This modifier means that the rate of growth decreased by 1% each year and resulted in a consumption profile out to 2080 that was increasing year-over-year but increasing by a smaller amount each year. For the higher growth scenarios (scenarios C, D, G, and H) the final growth rate in 2080 was made to be equivalent to the final growth rate in 2080 as extrapolated for the AEO 2011 Reference Case. This final growth rate in 2080 for the AEO 2011 Reference Case was derived using the same extrapolation method described above for the lower growth energy market scenarios. The growth rate over the 45-year period from 2036 to 2080 was made to decline linearly each year from the 2035 growth rate in order to reach the final growth rate in 2080 (the growth rate was interpolated between 2035 and 2080).

Total Natural Gas Consumption

NERA combined the power sector natural gas consumption and non-power sector natural gas consumption into a total natural gas consumption forecast that was used to formulate the natural gas price projections. These forecasts of annual total natural gas consumption were converted into projections of Henry Hub natural gas prices by applying a long-term supply elasticity of one.[62] This assumption of a unit elastic relationship comes from the NEMS-MEC model run results over the 2010 through 2035 period, which exhibit a supply price elasticity of approximately one.

A final adjustment was made to these derived Henry Hub natural gas prices in order to account for the potential impact of additional supply being accessible from a future Alaska natural gas pipeline that could be built given a sufficient price environment. The circumstances NERA assumed necessary in order to induce construction of this theoretical Alaska pipeline were wellhead natural gas prices above $8.18/MMBtu (2011$) for a period of three years (discussed in more detail in Section III). Projected wellhead natural gas prices were calculated by dividing the projected Henry Hub natural gas prices by a conversion factor of 1.13, which was sourced from AEO 2011. This period of three years of prices above $8.18/MMBtu (2011$) is assumed to be followed by a three-year construction period only after which the impact of additional natural gas supplies from the pipeline will be felt through slightly lower natural gas prices.

The profile of price impacts due to the Alaska pipeline (and Mackenzie Delta) was based on sensitivity scenarios for energy market scenario D (low natural gas supplies, high growth, carbon pricing). NERA evaluated two sensitivities for scenario D, one in which the Alaska Pipeline never came online and one in which it came online in 2024 (based on a slightly lower wellhead trigger price). NERA assessed how much lower the natural gas price was in scenarios with the Alaska Pipeline relative to the sensitivity in which the pipeline was not built. In the first year online, the prices (all in 2011$) were lower by $0.39/MMBtu and $0.36/MMBtu in the 2024 and 2027 online cases, respectively. In the following year, the price differences were $0.71 and $0.80, followed by $1.00 and $0.99. NERA calculated the price differences in all years out to 2035. The sensitivity case with the 2024 online year provided NERA with 12 data points and scenario D (pipeline in service in 2027) provided nine data points. NERA took the average of the nine data points and then also utilized the additional three data points from the 2024 online case. In years 10, 11, and 12, the price decline from the 2024 case were $0.25, $0.27, and $0.34. These three average $0.29 and NERA used this price reduction in all years after year 9 of the Alaska Pipeline becoming operational. Figure 24 provides the average price declines attributable to the additional supply of natural gas from Alaska.

Figure 24: Price Reduction Attributable to Alaska Pipeline and Mackenzie Delta (2011$/MMBtu)

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10+
$0.37	$0.75	$1.00	$0.96	$0.94	$1.03	$0.73	$0.46	$0.40	$0.28

The adjustments for the Alaskan gas were the final step in the extrapolation.

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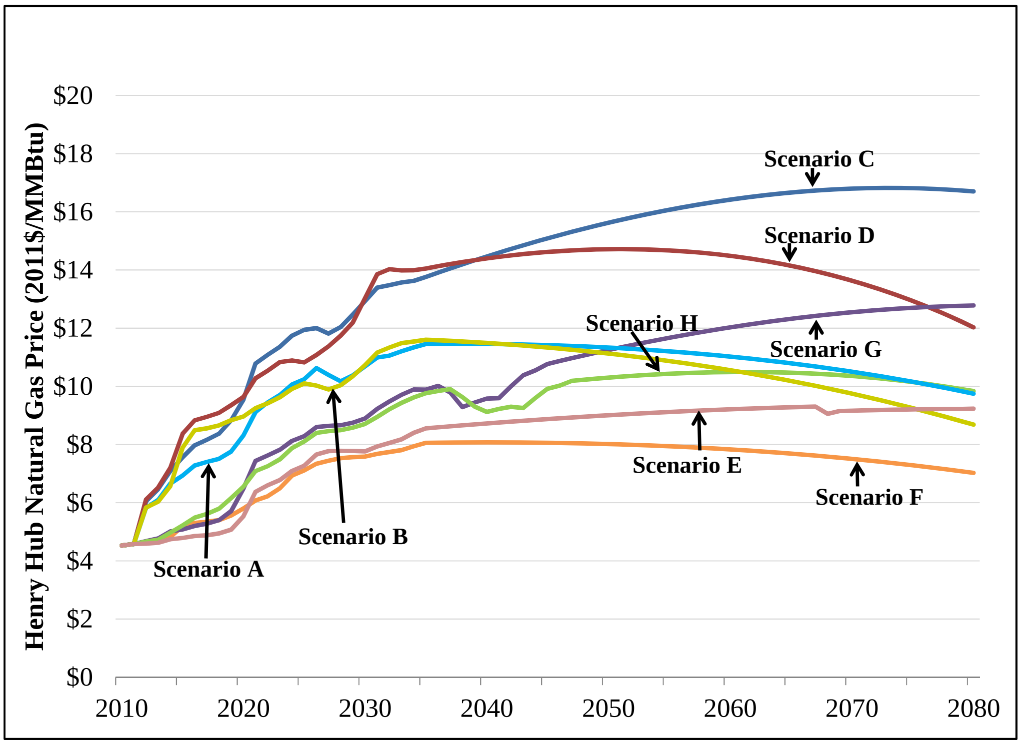
[62] While NERA used consumption figures, it was assumed that all incremental consumption is met by domestic supply, and hence it is appropriate to use a supply elasticity.

F. Resulting Natural Gas Price Forecasts

The results of the Henry Hub natural gas price projections (in 2011$) out to 2080 displays a wide range of outcomes depending on the energy market scenario conditions. This distribution of results demonstrates the sensitivity of such long-range projections to key underlying assumptions as well as the different price evolution paths possible given certain economic conditions. The full price projection curves are in Figure 25 and some snapshots of price throughout the projections are in Figure 26. These natural gas prices assume a natural gas combined cycle deployment in Iowa. The prices with a nuclear deployment would be slightly lower because of the incrementally lower natural gas demand as the nuclear deployment in Iowa replaces the natural gas combined cycle deployment.

Figure 25: Henry Hub Natural Gas Price Projections through 2080 (2011$/MMBtu)



Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes

Prices in 2080 ranged from a low of $7.02/MMBtu, (scenario F – high natural gas supply, low growth, carbon pricing), to a high of $16.70/MMBtu (scenario C- low natural gas supply, high growth, no carbon pricing) in 2011$. The highest price point under any energy market scenario was $16.83/MMBtu in 2073 under scenario C.

Figure 26: Snapshots of Henry Hub Natural Gas Price Projections to 2080 (2011$/MMBtu)

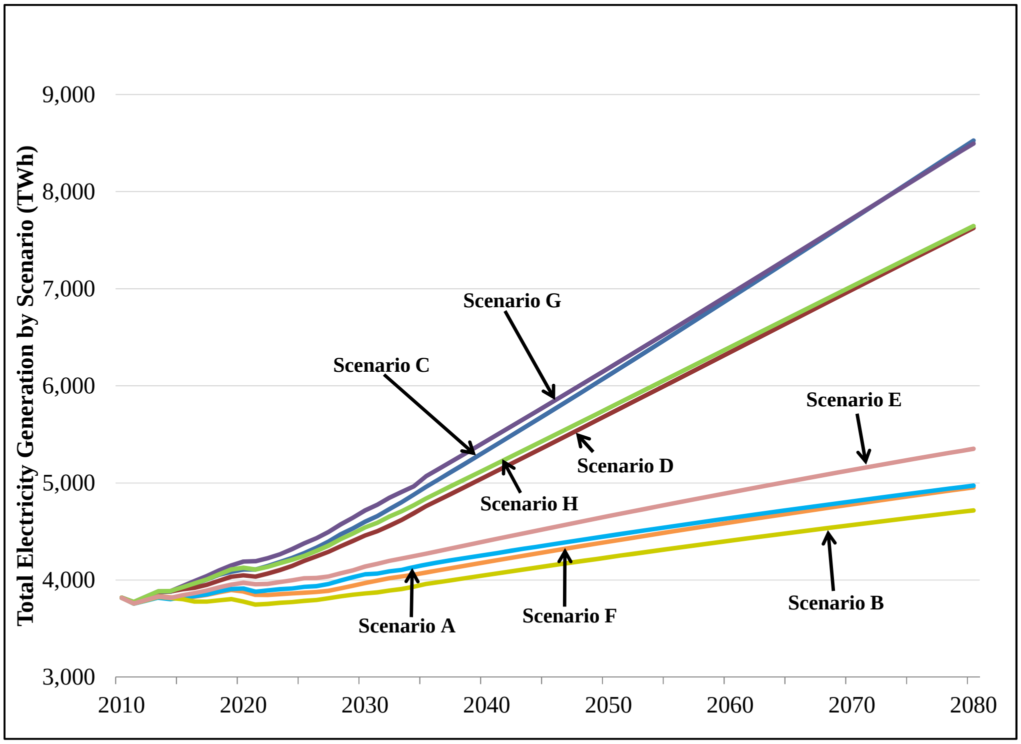
	Description	2020	2035	2050	2065	2080
Scenario A	Low Gas Supply, Low Growth, No Carbon	$8.32	$11.46	$11.33	$10.79	$9.75
Scenario B	Low Gas Supply, Low Growth, Carbon	$8.97	$11.60	$11.13	$10.19	$8.68
Scenario C	Low Gas Supply, High Growth, No Carbon	$9.54	$13.76	$15.63	$16.66	$16.70
Scenario D	Low Gas Supply, High Growth, Carbon	$9.64	$14.05	$14.72	$14.15	$12.03
Scenario E	High Gas Supply, Low Growth, No Carbon	$5.53	$8.56	$9.01	$9.28	$9.23
Scenario F	High Gas Supply, Low Growth, Carbon	$5.80	$8.06	$8.02	$7.69	$7.02
Scenario G	High Gas Supply, High Growth, No Carbon	$6.48	$9.89	$11.25	$12.32	$12.78
Scenario H	High Gas Supply, High Growth, Carbon	$6.55	$9.77	$10.30	$10.47	$9.84

The results indicate that economic growth had the greatest impact on price evolution through 2080. This impact was greater than the available natural gas supply through 2080, although natural gas supply is a more significant factor through 2050. The higher growth scenarios (scenarios C, D, G, and H) exhibit a significant upward shift in their price curves compared to their lower growth counterparts. Interestingly, when evaluating scenarios in which the only factor changing is natural gas supply (*e.g.*, scenario A to scenario E, or scenario B to scenario F), one can see that while the influence on price is strong in early years, this effect begins fading around 2040. After this point, the high and low natural gas supply scenarios begin to converge over time. The influence of a carbon price seems to be of tertiary influence and only begins taking effect in the post-2040 period; it has more of an impact on the divergences of forecasted natural gas price approaching the 2080 time horizon as opposed to the forecasted natural gas prices during the middle projection years from 2045 to 2065.

G. Electricity Demand

The total electricity generation in 2080 varies widely across scenarios with regard to the underlying economic assumptions. Similar to natural gas prices, the primary driver of the overall generation is the overall rate of economic growth assumed. The higher economic growth scenarios (scenarios C, D, G, and H) have 2080 electricity generation in the 7,600 TWh to 8,500 TWh range while the lower growth scenarios have an electricity generation in the 4,700 TWh to 5,300 TWh range.

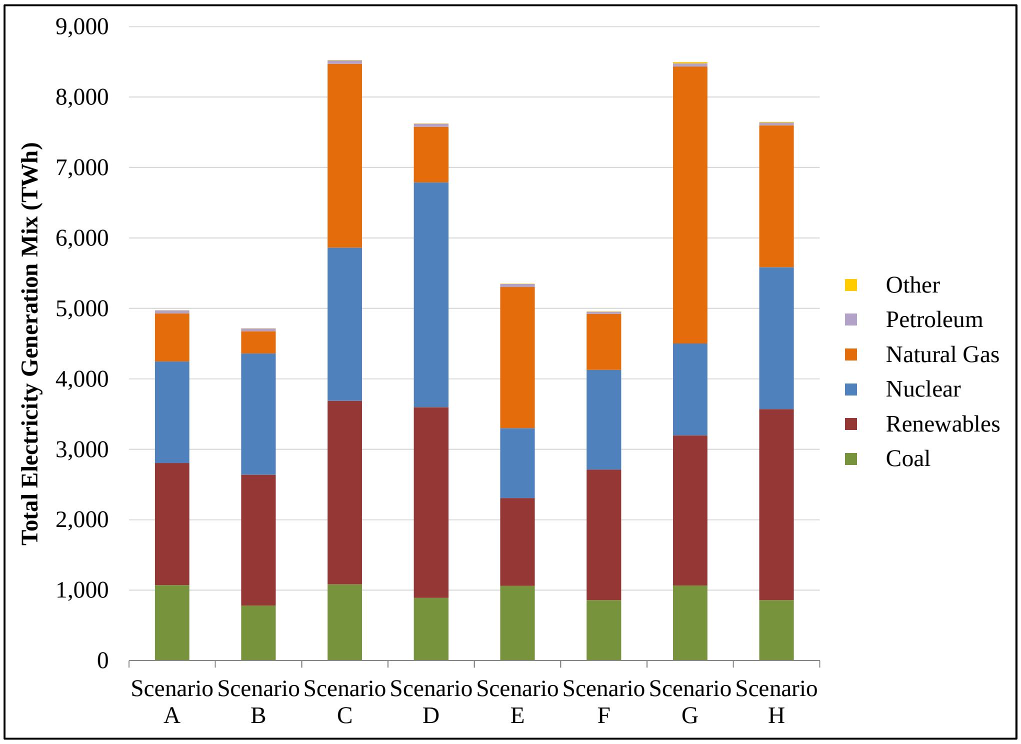
Figure 27: Annual Electricity Demand by Scenario



Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes

The difference in total electricity generation between comparable scenarios with higher or lower assumed natural gas supply is minimal, with the main difference being in the makeup of the generation mix. These differences can be seen in Figure 28. The lower natural gas supply energy market scenarios (scenarios A through D) have greater nuclear generation at the expense of natural gas generation as would be expected, and vice versa. It is interesting to note that this tradeoff applies even in the presence of a carbon price. For example, scenario D and scenario H both have a carbon price, but differ in their natural gas supply assumption. The difference in nuclear generation is nearly 1,200 TWh (scenario D being higher), and all the difference is accounted for by reducing natural gas generation. Renewable generation stays essentially the same between the two scenarios at approximately 2,700 TWh.

Figure 28: Generation Mix in 2080 (TWh)



Energy Market Scenario	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes

H. CO_2 Emissions

To ensure that the extrapolation was consistent with expectations for the energy market scenarios, NERA also extrapolated the electric sector CO_2 emissions. NERA's expectation for all of the scenarios was a reduction in CO_2 emissions from the power sector relative to 2010 emissions because of the assumed NSPS policy. For the energy market scenarios with a price on carbon emissions NERA expected further reductions in CO_2 emissions. The extrapolation of the electric sector CO_2 emissions is a function of the projected coal and natural gas-fired generation levels, the estimated heat rates of the generating units and the level of penetration of CCS on new units or added as a retrofit on existing units.

The extrapolation of the coal- and natural gas-fired generation was described in Section IV. The heat rates for the natural gas-fired generation over time were also described previously. For coal-fired generation heat rates, NERA evaluated the average heat rate of coal-fired generation in

2035 in each energy market scenario. Across the eight energy market scenarios, the average coal-fired heat rate ranged from 9,800 to 9,900 Btu/kWh. NERA kept this coal-fired generation heat rate constant over time for electricity generation that came from existing coal-fired generation, without CCS. Since no new coal-fired capacity without CCS was added in NEMS-MEC during the period 2013 through 2035[63] the only way in which the heat rate for any coal unit to decline in any significant manner would be through the addition of heat rate improvement projects. However, the future existence of such an improvement project is quite speculative at this time. Next, NERA made assumptions about the percentages of coal-fired generation and natural gas-fired generation that would be coming from units equipped with CCS (either new units with CCS or existing units that add CCS retrofits). NERA assumed that the scenarios with a carbon price would be more likely to have CCS than those that did not and reflected this by lagging for 20 years the CCS assumptions applied in the carbon price scenarios (scenario B, D, F and H) for the non-carbon price scenarios.[64] NERA further assumed that coal-fired generation would always have a higher share of CCS generation than natural gas-fired generation because it would be more cost-effective as a result of coal's higher carbon content. Figure 29 includes the assumed percentages of CCS-equipped generation from each fuel source in the two sets of scenarios (carbon price and no carbon price). These are based on NERA estimates on initial technology adoption rates, estimated adoption rates in 2050 based on cost estimates of CCS and CO_2 prices and finally estimated adoption rates in 2080 based on achieving significant reductions in CO_2 emissions from the electric sector. Years between 2050 and 2080 are interpolated.

Figure 29: Assumed Shares of Carbon Capture and Storage Generation from Coal and Natural Gas

Fuel Source	2040	2050	2060	2070	2080
Carbon Price Scenarios (Scenarios B, D, F and H)					
Coal	5%	30%	53%	77%	100%
Natural Gas	0%	15%	40%	65%	90%
No Carbon Price Scenarios (Scenarios A, C, E and G)					
Coal	0%	0%	5%	30%	53%
Natural Gas	0%	0%	0%	15%	40%

NERA also assumed that CCS applied to both coal-fired generation and natural gas-fired generation would come from new plants equipped with technology rather than retrofitting existing plants. Based on differences between new fossil generating plants with CCS and

63 New coal-fired generating units that are currently under construction are assumed to be completed by the end of 2012. After that, no new coal-fired generating units without CCS are allowed to be added.

64 The 20-year lag in the adoption of CCS is consistent with a general policy environment in which there is not a price on carbon. The absence of a price on carbon is likely to slow down the necessary development that is still needed to commercialize the technology.

without CCS, NERA estimated that the addition of CCS for both coal and natural gas onto a new plant would increase its heat rate by 1,000 Btu/kWh.[65] Thus, a new natural gas combined cycle without CCS, which NERA estimated to have a heat rate of approximately 6,650 Btu/kWh in 2050 would have a heat rate of 7,650 Btu/kWh if equipped with CCS. Similarly, in 2050 a new coal generating facility without CCS (if it were allowed to be built) would have a heat rate of 9,100 Btu/kWh and one with CCS would be 10,100 Btu/kWh. With these estimates NERA then proceeded to calculate the electric sector CO_2 emissions by multiplying the respective generation numbers by their respective heat rates and CO_2 contents for coal without CCS (only from existing coal-fired generators still in operation), coal with CCS, natural gas without CCS and natural gas with CCS.[66] The resulting electric sector CO_2 emissions are shown in Figure 30. The letter and number at the right of the chart are the energy market scenario and the respective reduction in electric sector CO_2 emissions relative to 2010.

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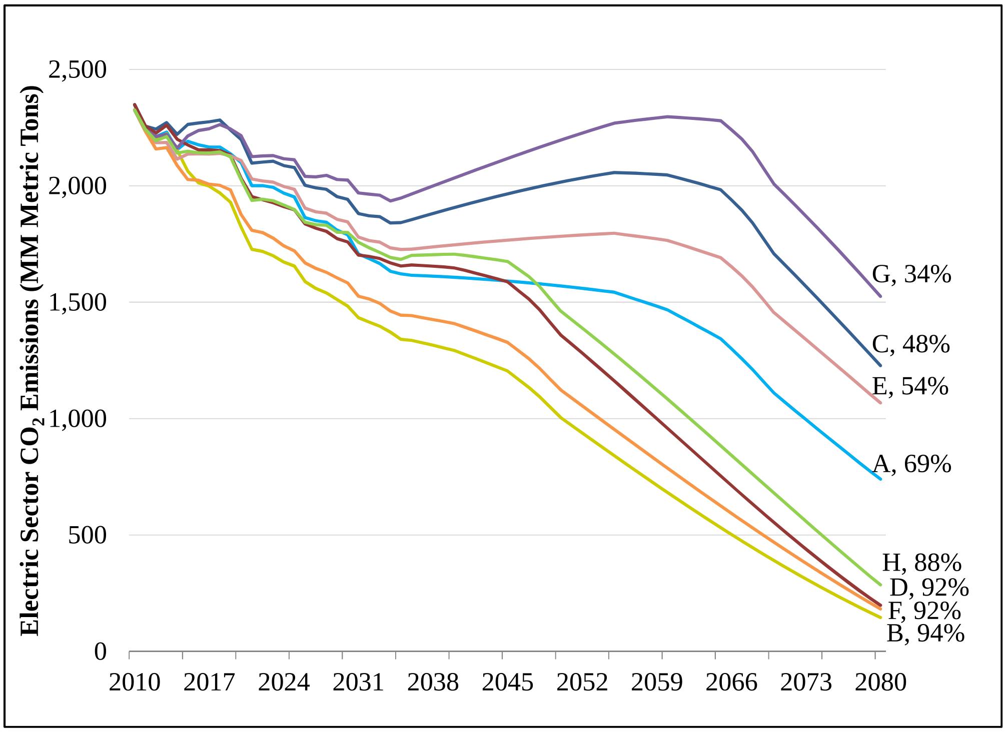
[65] Estimate based on comparison of heat rates for combined cycle and combined cycle with CCS per AEO 2011 (see Table 8.2 of Assumptions to AEO 2011).

[66] NERA assumed CO_2 contents of 206 lbs/MMBtu for coal and 116.7 lbs/MMBtu for natural gas. There was also a minimal amount of generation from petroleum fuels, and NERA kept that level of generation and the associated CO_2 emissions constant post-2035.

Figure 30: Electric Sector CO_2 Emissions by Scenario, Percentages are Decrease from 2010 Levels (Million Metric Tons)



Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes

The four carbon price scenarios (scenarios B, D, F, and H) have 2080 CO_2 emissions reductions ranging from 88% to 94% from 2010 levels, which is consistent with NERA expectations of a carbon policy that makes very significant reductions (and consistent with EPA and EIA modeling of electric sector emissions for a range of CO_2 legislative proposals like H.R. 2454, the Waxman-Markey bill).[67] The reductions from 2012 through 2020 are primarily the result of the NSPS GHG policy and the resulting coal unit retirements. From 2020 through 2035, the reductions are attributable to a combination of the NSPS GHG policy and the carbon price, which begins in 2020. Post-2035, the reductions are solely attributable to the carbon price which has escalated significantly in real dollars.

67 These levels of CO_2 emissions reductions in the electric sector are consistent with EPA and EIA findings that the electric sector would need to be nearly decarbonized to achieve national CO_2 emission reductions

The four no carbon price scenarios (scenarios A, C, E, and G) also produce large reductions by 2080 ranging from 34% to 69%. The pattern of the reductions in the no carbon price scenarios is somewhat different than in the carbon price scenarios in that the CCS is assumed to come online with a 20-year lag compared to the carbon price scenarios. The reductions from 2012 through 2035 for the four no carbon price scenarios are primarily the result of the NSPS GHG policy and the resulting coal unit retirements. After the NSPS GHG policy has been fully implemented, CO_2 emissions begin to rise again in the no carbon price scenarios because of load growth, but never reach 2010 levels. Beginning in about 2055 the emissions then begin a steady decline as significant implementation of CCS begins. There is much greater uncertainty about the CCS penetration rates (as retrofits for both existing coal and natural gas combined cycle units and for new natural gas combined cycle units) in the no carbon price scenarios because there is not a carbon price to induce their adoption (all new coal-fired generating units would be required to have CCS if they are to be built, but there are no other requirements or inducements such as a carbon price). As such there would likely need to be some regulatory requirement that CCS be adopted on new plants.

I. Retail Electricity Rates

Electricity rates are an important part of the analysis, particularly for assessing the economic development impacts in Iowa. The retail electricity rates used in this analysis are a combination of outputs from the NEMS-MEC model, a starting electricity demand from MidAmerican, and revenue requirement calculations for new nuclear, and new natural gas combined cycle deployments.

The starting point for the retail electricity rates are the all sector electricity rates from the MROW region (the NEMS-MEC region in which Iowa is located) for the eight energy market scenarios that included new natural gas combined cycle deployments in Iowa. These were extrapolated out beyond 2035 through 2080 by applying the five-year compound average growth rate. These rates, and their extrapolation have no impact on the ultimate economic development or macroeconomic comparison between deploying new nuclear SMR and deploying new natural gas combined cycle, because ultimately, the only difference in the rates is associated with the revenue requirement for each type of deployment.

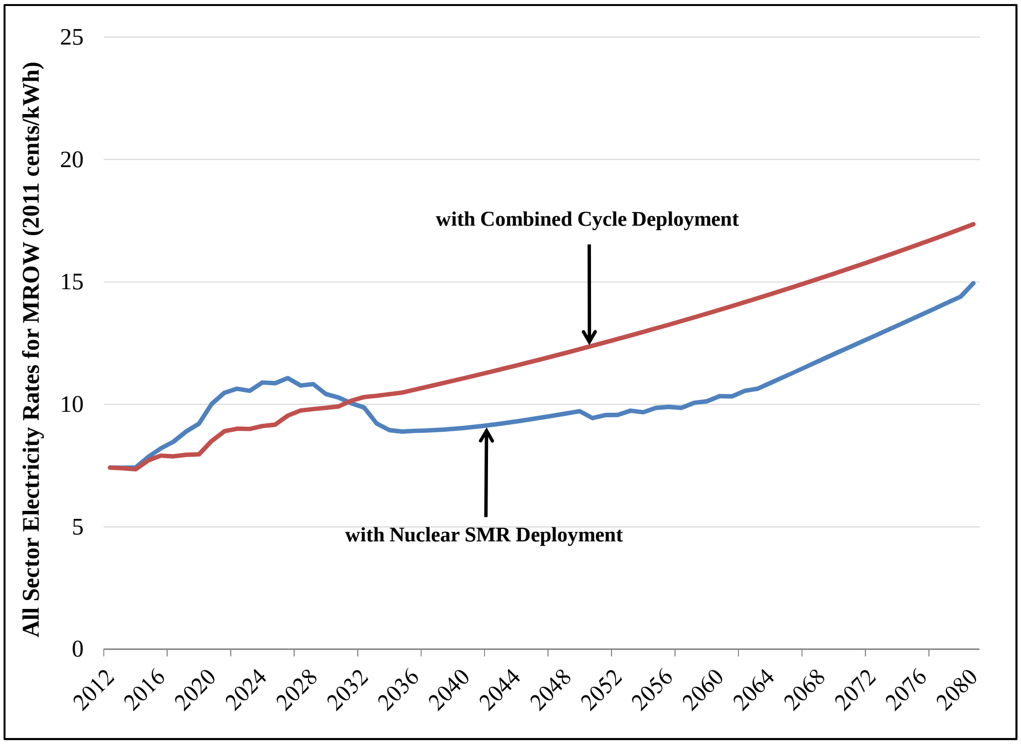
The total revenue requirement is calculated by multiplying the electricity rates by the energy market scenario specific electricity demand forecast. The MidAmerican electricity requirements forecast began with MidAmerican's projected 2012 demand of 23,416,500 MWh (provided by MidAmerican to NERA). This annual electricity demand forecast was then grown based on the year-over-year increase in demand for the U.S. since the MROW region was similar to the U.S. as a whole. Each of the eight energy market scenarios (scenarios A through H) had different electricity demand growth projections; the resulting estimated annual demand for MidAmerican customers was also different for each energy market scenario. Ultimately, the product of multiplying the different electricity rates by scenario and the annual electricity demand forecasts by scenario produced a total revenue requirement forecast for each scenario in each year, assuming a deployment of new natural gas combined cycle units by MidAmerican.[68]

To calculate the electricity rates assuming that new nuclear is built instead of natural gas combined cycle, it was necessary to net out the costs associated with the 2,400 MW of new natural gas combined cycle deployments (capital, fuel, O&M, *etc.*) from the extrapolated electricity rates, which included new natural gas combined cycle deployments in Iowa, and then add in the costs associated with deploying new nuclear. As such, NERA calculated the revenue requirement associated with deploying the new nominal 2,400 MW natural gas combined cycle deployment using a revenue requirement spreadsheet developed by MidAmerican. NERA confirmed that assumptions for returns on capital and equity, debt-equity shares, the capital spending schedule, inflation (and year-dollars) and O&M costs were appropriate. These costs were added to fuel and other cash expense costs specific to each energy market scenario. This total cost was then netted out from the revenue requirement that assumes a natural gas combined cycle deployment for MidAmerican.

To this adjusted electricity forecast NERA added in the revenue requirement associated with deploying the nominal 2,400 MW of new nuclear generation. This revenue requirement model was provided to NERA by MidAmerican, and originally produced by S&L (where appropriate, assumptions in this revenue requirement model and the natural gas combined cycle revenue requirement model were made to be consistent). The resulting values are the total annual revenue requirement assuming a new nuclear SMR deployment by MidAmerican. The annual electricity rates, assuming a deployment of new nuclear, are then calculated as the total revenue requirement for each energy market scenario divided by the annual electricity demand. Figure 31 shows the average electricity rates across eight energy market scenarios for both nuclear SMR and natural gas combined cycle deployments. Appendix A contains the comparative electricity rates for each energy market scenario.

[68] The revenue requirement that NERA calculated should not be construed as MidAmerican's projected revenue requirement or translated into MidAmerican's projected rates as actual rate calculations are much more complex and would depend on other factors such as commission decisions on appropriate returns for the utility.

Figure 31: All-Sector Retail Electricity Rates for Iowa with Nuclear SMR Deployment and Natural Gas Combined Cycle Deployment, Simple Average across Eight Energy Market Scenarios, 2012-2080 (2011¢/kWh)



V. FINANCIAL ANALYSIS

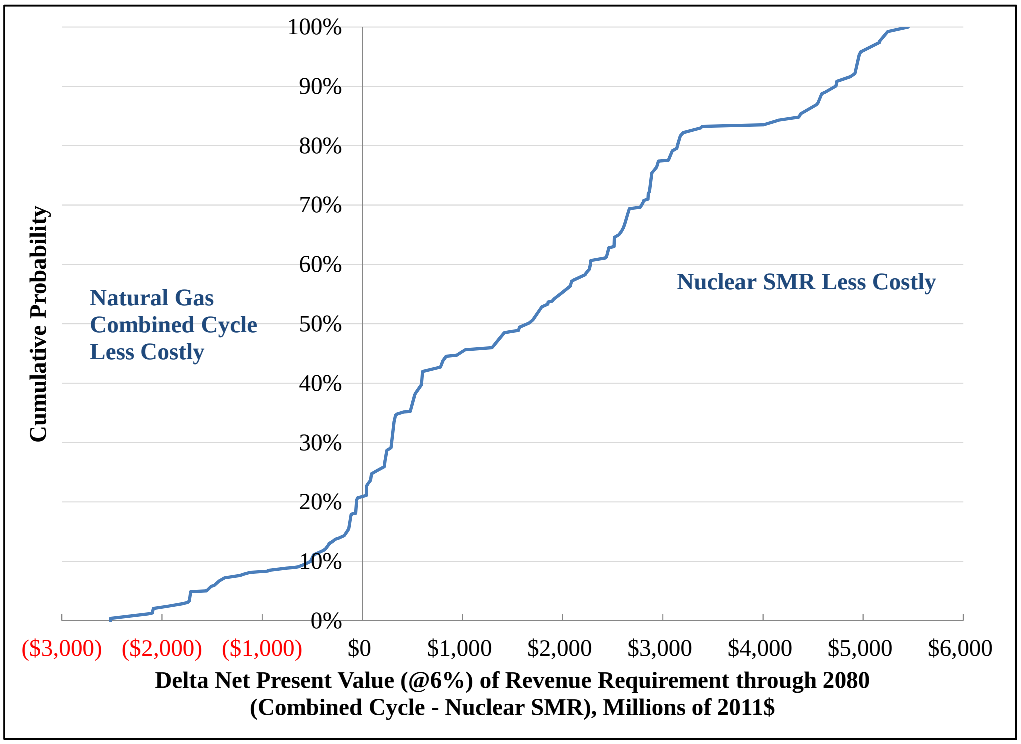
One of the primary questions to be answered by this report is whether nuclear generation (specifically nuclear SMR) would be a reasonable financial alternative relative to natural gas base load generation in a carbon constrained environment. To address this issue NERA developed a financial analysis which incorporated the natural gas price forecasts (see Section IV) with capital and operation and maintenance forecasts for the nuclear and natural gas base load alternatives. Two analyses were prepared: 1) a present value of revenue requirements, which represents the costs that would potentially be borne by MidAmerican customers, and 2) an annual cash flow analysis that is used primarily for calculating macroeconomic impacts.

A. Section Findings

The major findings of the financial analysis include:

- Comparing the gradual deployment of 2,400 MW (nominal) of incremental generating capacity from 2020 through 2033, a risk analysis demonstrates that the present value of projected revenue requirements through 2080 would be less for nuclear SMR deployment versus a natural gas combined cycle deployment approximately 80% of the time, if the SMR EPC price is realized (Figure 32).

Figure 32: Cumulative Distribution Function of the Differences in Present Value Revenue Requirements, Natural Gas Combined Cycle less Nuclear SMR, 2012-2080



- A critical determinant in this assessment is the actual EPC contract price for the delivery and installation in Iowa of the nuclear SMR facility. For these inputs, NERA relied upon information provided by MidAmerican and its consultant, S&L. The EPC price necessary to pursue the construction of a nuclear SMR would be negotiated in making a firm decision on whether or not to proceed with a nuclear SMR deployment at a future date.

- A second critical determinant in this assessment is the price of natural gas from the period that generation deployment would begin through the expected licensing life of a nuclear deployment (as described in Section IV).

- A third critical determinant in the financial assessment is the discount rate. For the base case, the discount rate NERA applied was developed from the estimated real cost of capital to MidAmerican.

- NERA identified three independent uncertainties that bear monitoring – the potential for delay in the nuclear SMR commercial operation dates, the potential for higher or lower fixed O&M/labor costs for both nuclear SMR and combined cycle natural gas units and the potential for higher or lower uranium fuel costs. NERA considered each of these three uncertainties in the final comparison of nuclear SMR and natural gas combined cycle.

B. Cash Flow and Revenue Requirement Analyses

Both the revenue requirement and cash flow analyses capture all of the incremental costs associated with the addition of 2,400 MW (nominal) deployment of either natural gas combined cycle or nuclear SMR generating capacity in Iowa over the period 2020 through 2033. The information used in the cash flow and revenue requirement analysis comes from multiple sources, including:

1. The natural gas and nuclear fuel price forecasts developed by NERA,
2. Nuclear capital cost and cash flow schedules provided by MidAmerican,
3. Natural gas combined cycle capital and operating costs and characteristics, and
4. Other assumptions described below.

The customer revenue requirement models for the nuclear and natural gas deployment assessments were provided by MidAmerican. The customer revenue requirement models include different recovery mechanisms for nuclear and natural gas in that the allowance for funds used during construction ("AFUDC") are recovered during construction for the nuclear deployments while those for the natural gas combined cycle are recovered after construction has been completed (typical of natural gas combined cycle units). All costs in both the revenue requirement and cash flow analyses are in real 2011 dollars. The cost categories and other inputs for nuclear and natural gas combined cycle are summarized in Figure 33.

Figure 33: Cost Categories and Other Inputs for Nuclear and Natural Gas Combined Cycle

Category	Nuclear SMR	Natural Gas Combined Cycle
Total Capacity	Nominal 2,400 MW (2,160 MW) added in nominal 300 MW increments between 2020 and 2033	Nominal 2,400 MW (2,400 MW) added in nominal 300 MW increments between 2020 and 2033
Total Generation	17.03 GWh annual after 2033 based upon capacity factor of 90% for a 2,160 MW deployment (2,400 MW nominal)[69]	17.03 GWh annual after 2033 based upon capacity factor of 81% for 2,400 MW deployment
Capital	Includes initial EPC capital, owner's non-EPC costs associated with initial construction, capitalized labor during construction and post-commercial annual capital investment	Includes initial EPC capital, owner's non-EPC costs, no post-commercial annual capital investment but end of life refurbishment/redeployment capital costs
Fuel	Based on uranium price forecast developed by NERA	Based on energy market scenario-specific natural gas price forecasts developed by NERA (NEMS-MEC model results), NERA's extrapolation of these prices beyond 2035, and pipeline delivery costs estimated by NERA with MidAmerican input
O&M Costs	O&M costs and labor, developed by MidAmerican	Variable and Fixed O&M costs from AEO 2011
Carbon Costs	None	Costs of emission allowances and/or costs for adding CCS (if applicable)
Revenue Requirement Financing	9.5% real return on equity, 4.4% real return on debt and 50/50 debt-equity ratio, book life of 40 years extended to 60 years with license extension	Same as for nuclear except book life of 30 years

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69 While the nominal capacity assumed for each nuclear SMR unit is 300 MW, there is no specific design that is exactly 300 MW. The unit specification utilized in the nuclear SMR cost figures is a 270 MW unit. The total annual generation based on a 90% capacity factor and a 270 MW unit is the same as that for a 81% capacity factor and a 300 MW unit.

Category	Nuclear SMR	Natural Gas Combined Cycle
Allowance for Funds During Construction	Recovered during construction, typical of nuclear deployments currently under construction by rate regulated utilities	Recovered after construction, typical of combined cycle units currently under construction by rate regulated utilities
Other	Includes decommissioning costs, fuel disposal costs, and relicensing costs	None

The assumed capital life for natural gas combined cycle is 30 years based on the assumptions from AEO 2011. At the end of the 30th year, the combined cycle units would be rebuilt (at the same real original capital cost) with these new replacement combine cycle units gaining the expected benefit of improved heat rates provided by the technology improvements over the 30 year period.[70] The capital life of the nuclear deployment was assumed at 40 years for an initial operating license followed by a 20 year license extension; this is currently typical of nuclear generating units licensed in the U.S.

C. Deterministic Results

Specific deterministic results were calculated for eight energy market scenario natural gas forecasts developed by NERA. None of the nuclear costs vary across the eight natural gas forecasts; the natural gas combined cycle costs for fuel and carbon emissions do vary across energy market scenarios since the natural gas prices are different in each scenario and only some scenarios include a price on carbon emissions.

The comparative net present value of revenue requirements for each of the eight natural gas forecasts are shown on Figure 34.

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70 If the scenario includes the addition of CCS on the natural gas combined cycle in 2050 then this increases the capital costs (shown as CCS retrofit) and increases the heat rate by 1,000 Btu/kWh.

Figure 34: Net Present Value of Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment for Eight Discrete NERA Natural Gas Forecasts (2011$)

Energy Market Scenario	NPV of Combined Cycle Revenue Requirement (Millions$)	NPV of Nuclear SMR Revenue Requirement (Millions$)	NPV of Difference in Revenue Requirements (Millions$)
A	$13,080	$12,765	$315
B	$15,417	$12,765	$2,652
C	$15,655	$12,765	$2,890
D	$17,726	$12,765	$4,961
E	$11,051	$12,765	($1,713)
F	$12,806	$12,765	$41
G	$12,621	$12,765	($144)
H	$14,556	$12,765	$1,791
Probability Weighted Average	$14,482	$12,765	$1,717

Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes
Probability	23%	10%	17%	17%	8%	8%	5%	12%

In scenarios where there is a carbon price (scenarios B, D, F and H), the natural gas combined cycle units incur the cost of purchasing emission allowances equal to the total carbon emissions and these scenarios are consistently higher in revenue requirements than the No Carbon scenarios. The model calculates carbon emissions based on a carbon content of 116.7 lbs/MMBtu, multiplied by the fuel consumption (in MMBtu), which is a function of the weighted average heat rate of the natural gas combined cycle units. In those scenarios which include a carbon price, the model assumed that the units add CCS in 2050 as a cost effective alternative to escalating carbon allowance price for the natural gas combined cycle units. This results in a capital outlay of $1,000/kW, but it also reduces CO_2 emissions by 90%. At the same time, the CCS causes a heat rate penalty that increases the heat rate by 1,000 Btu/kWh, increases variable O&M costs by $3.07/MWh (in 2011$), and adds a transportation and storage cost of

$11.00/metric ton of captured CO_2.[71] These costs and heat rate additions are incremental to costs of redeployment/refurbishing the natural gas combined cycle units starting in 2050 after their initial 30 years of operating.

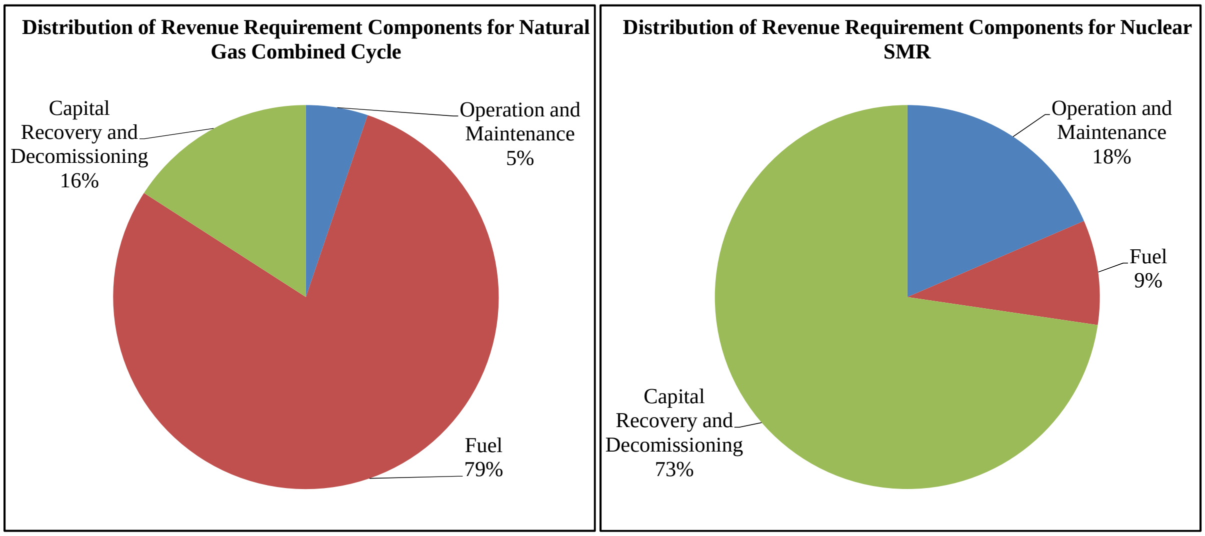
The allocation of costs between the major cost components for the most likely energy market scenario (scenario A, low natural gas supply, low economic growth, and no carbon price) are shown in Figure 35. This figure and Figure 36 show the significant difference in the allocation of costs between the nuclear and natural gas deployment alternatives. As shown in Figure 36, capital investment dominates the revenue requirements for a nuclear SMR deployment while fuel costs dominate revenue requirements for the natural gas combined cycle deployment. These cost allocation differences help to focus on the key sensitivities for these two deployment alternatives.

Figure 35: Net Present Value of Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment for Scenario A (Low Natural Gas Supply, Low Economic Growth and No Carbon Price) (2011$)

Cost Category	NPV of Combined Cycle Revenue Requirement (Millions$)	NPV of Nuclear SMR Revenue Requirement (Millions$)	Difference in Revenue Requirements (Millions$)
Capital Recovery and Decommissioning Costs	$2,077	$9,276	($7,199)
Operation and Maintenance Costs	$678	$2,362	($1,684)
Fuel and Fuel Disposal Costs	$10,324	$1,126	$9,198
Total	$13,079	$12,764	$315

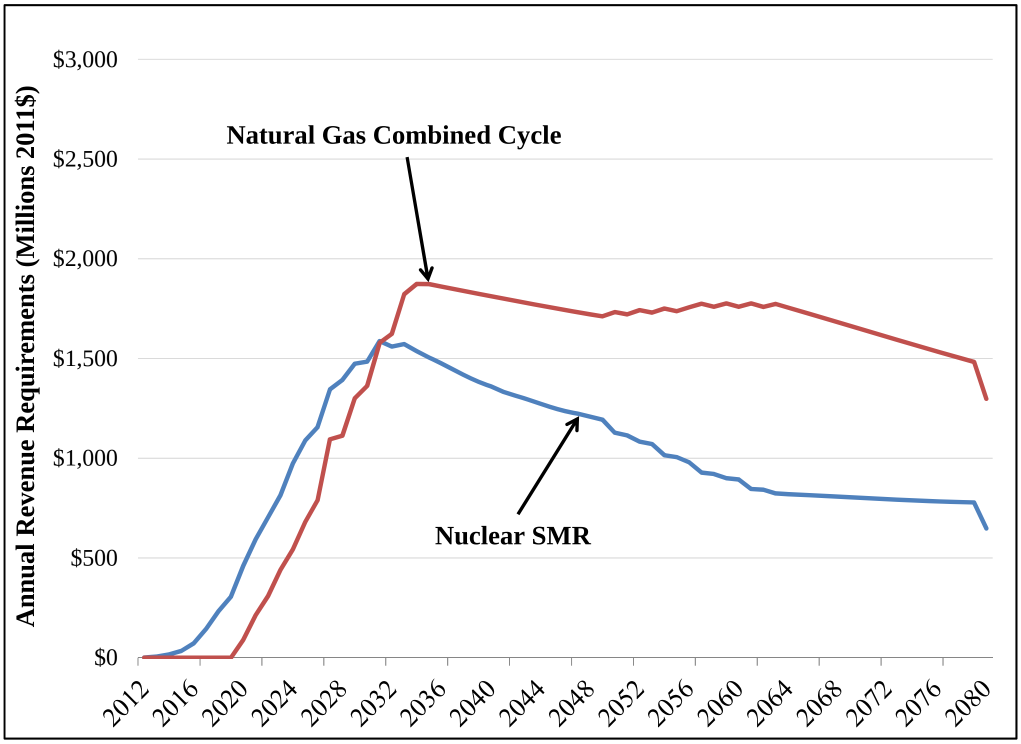
[71] The cost of a CCS retrofit on a natural gas combined cycle unit is quite uncertain. NERA has looked at the difference between the capital cost of an advanced combined cycle and an advanced combined cycle with CCS from AEO 2011 to estimate the cost. The heat rate differential, variable O&M, and cost of transport and storage are also from AEO 2011.

Figure 36: Allocation of NPV Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment for Scenario A (Low Natural Gas Supply, Low Economic Growth and No Carbon Price)



The annual revenue requirement differences between the nuclear and natural gas deployment alternatives are highlighted in Figure 37. Revenue requirements begin earlier for the nuclear SMR deployment because of the assumed recovery of AFUDC. However, during the last 60 years of the study period revenue requirements are higher for the natural gas combined cycle deployment; due to discounting, the total present value of revenue requirements for scenario A is only $371 million higher for the natural gas combined cycle deployment when compared to the nuclear SMR deployment.

Figure 37: Annual Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment for Scenario A, 2012-2080 (Low Natural Gas Supply, Low Economic Growth and No Carbon Price) (2011$ Millions)



D. Sensitivity Analysis

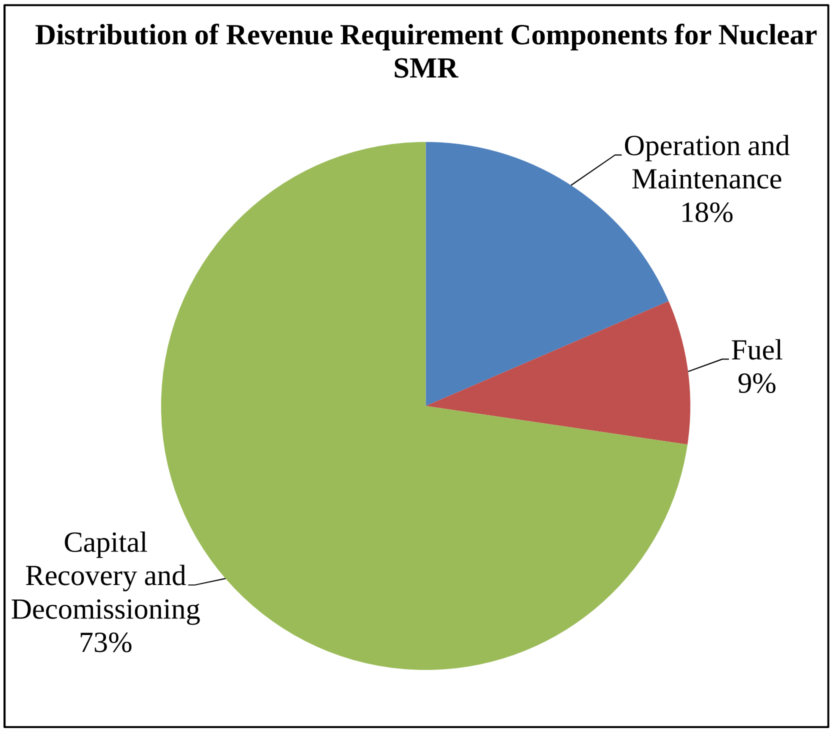
A sensitivity analysis determines which independent uncertain variables are critical to cost comparisons between natural gas combined cycle and nuclear generation deployment. Independent uncertain variables are those that are unlikely to have an impact on other variables (*i.e.*, are not necessary to evaluate within the NEMS-MEC model), but which have a sufficient degree of uncertainty as to their potential future values.

1. Nuclear SMR EPC Capital Cost

The capital cost to deploy nuclear SMR is uncertain because no pricing history exists for the EPC contract for a nuclear SMR deployment. The assessment of the EPC contract price is especially important for the following reasons:

- As shown in Figure 38, of the total capitalized investment for a nuclear SMR deployment, over 73% of the revenue requirement attributable to the nuclear capital investment is associated with the EPC contract price and other capitalized costs.[72] Therefore the EPC contract price is a critical component to be assessed in a sensitivity analysis.

Figure 38: NPV of Revenue Requirement of Capital Investment in Nuclear SMR Deployment



- For the nuclear SMR capital costs, the base assumption is that the EPC contract price represents a "quoted" or offered price for the construction of the nuclear SMR units from the vendor. It is likely and reasonable that the quoted EPC price will be notably lower than FOAK actual construction costs due to the desire of the vendor to incentivize a FOAK construction or to reflect DOE design subsidies.[73] Although this quoted EPC price may not be reflective of the actual costs incurred by the vendor to complete the FOAK project, it would be the cost incurred by MidAmerican (thus affecting the level of rates to be collected from the customer). Therefore the quoted EPC price is the appropriate cost to include in the revenue requirement calculation. To obtain an order, the SMR vendor would need to provide an EPC contract price that is competitive with the costs of alternative forms of generation (*e.g.*, natural gas combined cycle) given the

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72 Other capitalized costs include owner's costs, capitalized labor costs associated with labor prior to the plant coming online, required returns on equity, cost of financing debt, tax costs, and book depreciation of assets.

73 The DOE SMR Funding Opportunity Announcement provides a matching fund amount of $452 million. See http://www.grants.gov/search/search.do?oppId=138813&mode=VIEW.

economic conditions and expected natural gas price. In addition, if the nuclear EPC contract is not competitive, there would still be ample time for MidAmerican to select a natural gas combined cycle deployment instead of a nuclear SMR deployment.

- While the repeated and systematic production of a standard nuclear SMR design is expected to result in lower n^{th}-of-a-kind EPC costs, this remains an expectation until multiple reactors are built. In addition, it is uncertain if the successful reactor vendor will pass on any of these n^{th}-of-a-kind EPC costs through a reduced EPC contract price.

MidAmerican provided the base EPC price of $4,298/kWe[74] for an industry FOAK unit (which applies to operating capacity of the first nominal 600 MW unit), and gradually decreasing in price to $3,344 for an n^{th}-of-a-kind unit, (which applies to the last nominal 600 MW of the total 2,400 MW deployment). In total, the base capital costs (EPC price) average $3,644/kWe (total operating capacity of 2,160 MW). The capital investment including the owner's costs and capitalized labor was estimated by MidAmerican at $5,364/kWe.

Figure 39 includes some ranges of overnight capital cost (EPC costs) estimates based on publicly-available studies and reports.

[74] Excludes initial fuel loaded into reactors, which is recovered in fuel cost.

Figure 39: Estimates of Overnight Capital Cost of Nuclear SMR (2011 US$/kWe)

Source (Date)	Lower ($/kWe)	Upper ($/kWe)	Notes
Belfer, Venice workshop (2011)[75]	$2,000	$8,000	Based on a survey of vendors
Energy Policy Institute of Chicago (2011) [76]	$4,778	$7,908	Upper is 1st-of-a-kind, Lower is Nth-of-a-kind
Energy Policy Institute (2010) [77]	$3,150	$7,350	Escalated from 2010$ at 5%
Generation mPower statements[78]	<$5,000	<$5,000	SMR vendor estimate
Holtec SMR-160[79]	$5,000	$5,000	SMR vendor estimate
NuScale Power statements[80]	$4,000	$4,000	SMR vendor estimate
Range	$2,000	$8,000	

Because of the significant range in the EPC contract price forecast, NERA determined a breakeven EPC contract price for each energy market scenario to assess this important cost component. The breakeven EPC costs are shown on Figure 40. For example, if the nuclear SMR deployment EPC contract price is above $4,514/kW (the blue horizontal mark on the line) for scenario A, the deterministic evaluation shows the natural gas option to have a lower present value when compared to the nuclear deployment alternative. If the EPC price is below the

75 International Workshop on Research, Development, and Demonstration to Enhance the Role of Nuclear Energy in Meeting Climate and Energy Challenges; Anadon, Bosetti, Bunn, Catenacci, and Lee (Belfer Center); April 7-8, 2011; International Center for Climate Governance; Island of San Giorgio Maggiore, Venice, Italy; p. 16.

76 "Small Modular Reactors – Key to Future Nuclear Power Generation in the U.S.," University of Chicago, Energy Policy Institute at Chicago (EPIC), Technical Paper, Revision 1, Nov 2011, p. 17. Also in Table 2 on p. 19 – this is for a LEAD plant, not the LEAD/2 option.

77 The Energy Policy Institute; Economic and Employment Impacts of Small Modular Nuclear Reactors; June 2010; p. 30.

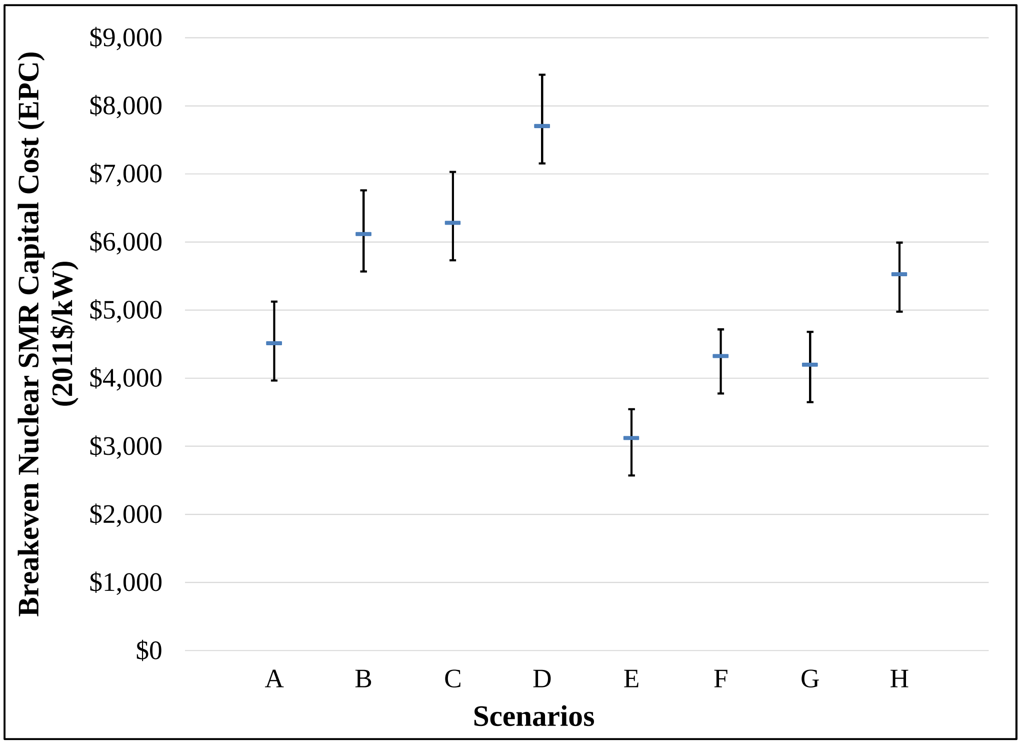
78 Generation mPower SMR Plant and FOA Progress, Platts 3rd Annual Small Modular Reactors Conference May 21, 2012; Ali Azad Chief Business Development Officer The Babcock & Wilcox Company http://www.platts.com/IM.Platts.Content/ProductsServices/ConferenceandEvents/2012/pc230/presentations/Ali_Azad.pdf.

79 Holtec's Small Modular Reactor, SMR-160, Advances to the Detailed Design and Safety Analysis Phase, cost for single deployment, July 23, 2012 http://www.smrllc.com/news/hh_27_11.pdf.

80 "Nuclear Startup NuScale Suspends Operation," Greentechmedia, Jan 20, 2011 (http://www.greentechmedia.com/articles/read/nuclear-startup-nuscale-suspends-operation/#).

$4,514/kW value for scenario A, the nuclear SMR revenue requirement is lower. Including the other sensitive independent uncertainties (discussed in the following sections), the breakeven nuclear SMR EPC cost could be as high as $5,125/kW or as low as $3,964/kW for scenario A.

Figure 40: Breakeven Nuclear SMR First-of-a-Kind EPC Contract Price for Eight Energy Market Scenarios



Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes

Because of the long lead time for a nuclear deployment (upwards of 10 years) this allows a utility like MidAmerican to preserve the option for a nuclear deployment alternative; if the EPC contract offered at the time when the decision needs to be finalized turns out not to be competitive, the utility will still be able to deploy natural gas combined cycle units that require a much shorter deployment schedule.

2. Nuclear Delay

Any delay of the initiation of licensing and/or construction could result in a delay of the online date for the nuclear capacity. The model assumes that MidAmerican will submit a combined construction and operating license ("COL") application for the first nuclear site in October 2013. The nuclear delay sensitivity assumes a 2.5 year delay beginning in the second quarter of 2012.

According to MidAmerican, the expected construction time of each nominal 300 MW unit is three years. The delay sensitivity assumes the first nominal 300 MW unit, will be delayed by 2.5 years. Given the scheduling of subsequent units at the same site, which would be utilizing the same labor at each unit, this would also delay the remaining nominal 2,100 MW by the same 2.5 years.

The financial impacts on cash flows and revenue requirements as a result of a delay (including EPC costs, variable operating costs, and labor requirements) are calculated through a nuclear revenue requirement model provided by MidAmerican. NERA assumed for a sensitivity case that the nuclear unit's generation deployment would be delayed 2.5 years and therefore variable costs such as fuel and fuel disposal would also be delayed 2.5 years. However, given that the nuclear generation was assumed to be needed to meet customer demand, there is a cost for replacement power and capacity. The quantity of replacement power is equal to the generation that was expected from the nuclear generator, but is not available due to the delay. The cost for the replacement power is equal to the average cost of generation in the MROW electricity region (from the NEMS-MEC model), plus a 20% premium. The cost of replacement capacity is assumed to be $150/kW, a high-end estimate of the annualized costs of a new combustion turbine. The model provided by MidAmerican reduces EPC and Owner's cash flows during the delay period to recognize the reduction in these activities during the delay period. During the period of the delay, EPC cash flows are reduced to 15% of their pre-delay value and Owner's cash flows are reduced to 80% of their pre-delay value. The MidAmerican labor cash flows are held constant during the delay under the assumption that there would be no layoffs for a reasonably short delay.

The results of this sensitivity case are shown in Figure 41. The 2.5 year delay in the nuclear deployment lowers the probability weighted average present value of revenue requirements for the nuclear SMR deployment relative to the natural gas fueled deployment by an average of $64 million. This improvement is attributable to delaying the relatively high upfront capital costs associated with deploying nuclear. The relatively small magnitude of the improvement is due to the offsetting costs of replacement power purchases during the period of delay and differences depending on whether or not there is a carbon price in the scenario.[81]

[81] While the nuclear delay results in lower present value costs on a probability weighted average basis, the nuclear delay results in higher present value costs in the scenarios with a carbon price.

Figure 41: Net Present Value of Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment - Nuclear Delay Sensitivity (2011$)

Energy Market Scenario	NPV of Combined Cycle Revenue Requirement (Millions$)	NPV of Nuclear SMR Revenue Requirement (Millions$)	NPV of Difference in Revenue Requirements (Millions$)
A	$13,083	$12,493	$590
B	$15,420	$12,802	$2,618
C	$15,659	$12,703	$2,956
D	$17,730	$13,002	$4,728
E	$11,054	$12,429	($1,375)
F	$12,809	$12,727	$82
G	$12,625	$12,585	$39
H	$14,560	$12,895	$1,665
Probability Weighted Average	$14,486	$12,709	$1,776

Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes
Probability	23%	10%	17%	17%	8%	8%	5%	12%

3. Retire or Refurbish Natural Gas Combined Cycle

NERA and AEO 2011 assume a capital life of 30 years for new natural gas combined cycle units. Thus, a natural gas unit built in 2020 would operate through 2049. At the end of the 30-year life, NERA considered two options. The base option assumes the natural gas unit would be retired and replaced with a new natural gas combined cycle unit and would incur the full capital costs for the new unit. As a sensitivity case, NERA considered that the unit could be refurbished at a cost of 25% of the cost of a new deployment. In each instance, the heat rates would be reflective of the latest technology. Decisions about adding CCS to the natural gas combined cycle unit are independent of this sensitivity and instead depend on whether the scenario includes carbon prices.

This decision was not analyzed in-depth from a revenue requirement perspective since the decision to refurbish rather than retire and redeploy the natural gas units at the end of the 30-year life has a minimal impact. The relatively low capital expenditure required for the natural gas combined cycle in addition to the refurbishment discount to 25% of the cost of a new deployment, and the fact the cost is incurred after 30 years, results in small cost impacts on a present value basis.

4. Uranium Fuel Price

While capital is the most significant cost for nuclear units, uranium fuel costs are also an important cost component. Uranium fuel costs are not subject to the volatility observed in natural gas markets because once purchased, the nuclear fuel remains in the reactor for a long period (typically 18 to 24 months). Nevertheless, there is uncertainty associated with available stocks of uranium in the global market so the average future price level is still uncertain. The base uranium fuel price forecast grows at a real rate of 1.0% per year. The NERA high cost price estimate grows at 2.0% per year, while the NERA low cost price estimate grows at 0.25% per year.

The results of this sensitivity case are shown in Figure 42 and Figure 43. The sensitivity case with lower uranium prices improves the present value of revenue requirements for the nuclear SMR deployment relative to the natural gas combined cycle deployment by an average of $204 million. The higher uranium price sensitivity case reduces the difference in present value of revenue requirements for the nuclear SMR deployment relative to the natural gas combined cycle deployment by an average of $373 million.

Figure 42: Net Present Value of Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment – Low Uranium Fuel Price Sensitivity (2011$)

Energy Market Scenario	NPV of Combined Cycle Revenue Requirement (Millions$)	NPV of Nuclear SMR Revenue Requirement (Millions$)	NPV of Difference in Revenue Requirements (Millions$)
A	$13,080	$12,561	$519
B	$15,417	$12,561	$2,856
C	$15,655	$12,561	$3,094
D	$17,726	$12,561	$5,164
E	$11,051	$12,561	($1,510)
F	$12,806	$12,561	$245
G	$12,621	$12,561	$60
H	$14,556	$12,561	$1,995
Probability Weighted Average	$14,482	$12,561	$1,921

Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes
Probability	23%	10%	17%	17%	8%	8%	5%	12%

Figure 43: Net Present Value of Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment – High Uranium Fuel Price Sensitivity (2011$)

Energy Market Scenario	NPV of Combined Cycle Revenue Requirement (Millions$)	NPV of Nuclear SMR Revenue Requirement (Millions$)	NPV of Difference in Revenue Requirements (Millions$)
A	$13,080	$13,138	($58)
B	$15,417	$13,138	$2,278
C	$15,655	$13,138	$2,516
D	$17,726	$13,138	$4,587
E	$11,051	$13,138	($2,087)
F	$12,806	$13,138	($332)
G	$12,621	$13,138	($517)
H	$14,556	$13,138	$1,418
Probability Weighted Average	$14,482	$13,138	$1,344

Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes
Probability	23%	10%	17%	17%	8%	8%	5%	12%

5. CCS Retrofit Costs

There has been almost no testing of CCS retrofits on natural gas combined cycle units, and hence the cost estimates for such a retrofit are very uncertain. The NERA base assumption is that the capital cost for a CCS retrofit on a natural gas combined cycle unit will be $1,000/kW (consistent with AEO 2011 assumptions). If there were to be significant technological advancement for CCS, NERA estimated the cost could fall to as little as $500/kW. Because of the lack of CCS testing, NERA estimated that the cost for CCS on natural gas deployment could be as high as $2,000/kW.

This sensitivity case was not analyzed in-depth from a revenue requirement perspective since the precise cost of adding CCS onto natural gas combined cycle unit has a minimal impact. The capital expenditure required for the retrofit is not relatively large and it is heavily discounted on a present value basis due to the costs of a CCS retrofit not being incurred until 2047 (see Figure 47).

6. Major Overhaul for Nuclear

NERA conducted a sensitivity analysis in which major capital upgrades are required on each SMR nuclear unit after 40 years (above and beyond those included in post-COD capital expenditures). The cost of this major overhaul is equal to 25% of the capital (EPC) cost of originally constructing the plant. The base option is that this unplanned major overhaul is not required (incremental costs are zero). There cannot be a low cost estimate associated with this sensitivity case because the base assumption already assumes that the costs are zero.

This sensitivity case has a minimal impact on present value revenue requirements due primarily to the 40 years of discounting (see Figure 47).

7. Labor Costs/Fixed O&M

For the new nuclear SMR units, detailed labor costs have been provided by MidAmerican along with fixed O&M costs. For a new natural gas combined cycle unit, labor costs are embedded in the fixed O&M costs. The labor/fixed O&M costs for the nuclear SMR units are significantly larger than those for the natural gas combined cycle generating units (see Figure 36). There is uncertainty regarding both the cost of labor and the quantity of labor (for both nuclear and natural gas combined cycle units), which jointly are reflected in labor costs. The NERA base assumption utilizes the detailed labor build-up and costs required by the nuclear unit deployment and the base level of fixed O&M for the natural gas combined cycle unit deployment. The NERA high cost estimate assumes that for each type of technology the labor/fixed O&M are 115% of the base cost; the low cost estimate assumes that the costs are 90% of the base estimate.

The results of this sensitivity case are shown in Figure 44 and Figure 45. The 115% labor and fixed O&M costs result in a net benefit to the natural gas combined cycle deployment when compared to the nuclear SMR deployment by an average of $428 million. The 90% labor and fixed O&M costs results in lower costs for a nuclear unit deployment compared to a natural gas deployment by an average of $285 million in the present value of revenue requirements.

Figure 44: Net Present Value of Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment – Low Labor/Fixed O&M Cost Sensitivity (2011$)

Energy Market Scenario	NPV of Combined Cycle Revenue Requirement (Millions$)	NPV of Nuclear SMR Revenue Requirement (Millions$)	NPV of Difference in Revenue Requirements (Millions$)
A	$13,055	$12,454	$600
B	$15,391	$12,454	$2,937
C	$15,629	$12,454	$3,175
D	$17,700	$12,454	$5,246
E	$11,026	$12,454	($1,428)
F	$12,781	$12,454	$327
G	$12,596	$12,454	$141
H	$14,531	$12,454	$2,076
Probability Weighted Average	$14,457	$12,454	$2,002

Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes
Probability	23%	10%	17%	17%	8%	8%	5%	12%

Figure 45: Net Present Value of Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment – High Labor/Fixed O&M Cost Sensitivity (2011$)

Energy Market Scenario	NPV of Combined Cycle Revenue Requirement (Millions$)	NPV of Nuclear SMR Revenue Requirement (Millions$)	NPV of Difference in Revenue Requirements (Millions$)
A	$13,118	$13,230	($113)
B	$15,455	$13,230	$2,224
C	$15,693	$13,230	$2,462
D	$17,764	$13,230	$4,533
E	$11,089	$13,230	($2,141)
F	$12,844	$13,230	($386)
G	$12,659	$13,230	($572)
H	$14,594	$13,230	$1,364
Probability Weighted Average	$14,520	$13,230	$1,289

Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes
Probability	23%	10%	17%	17%	8%	8%	5%	12%

8. Natural Gas Combined Cycle Capacity Factor

For comparison purposes, NERA has assumed that a nuclear SMR and natural gas combined cycle deployment would annually produce the same amounts of electricity. This keeps the comparison of nuclear and natural gas combined cycle simpler in that it was not necessary to make any assumptions regarding the cost or revenues resulting from purchases or sales of energy for the base comparison.

Over the last five years, the U.S. nuclear fleet has averaged approximately a 90% annual capacity factor.[82] Based on a range of observed operational outputs in natural gas combined cycle

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[82] See http://www.nei.org/filefolder/US_Nuclear_Generating_Statistics.xls.

generation units, NERA considered a range of potential capacity factors above and below the 81% base assumption. At the high end, an assumption of a 90% capacity factor was applied, as a few natural gas combined cycle units have demonstrated the ability to consistently operate at that level or higher. The low end assumption is a 70% capacity factor, which could be representative of a situation when natural gas generation is displaced by any number of lower dispatch cost resources.

The main areas of cost impacted by the natural gas combined cycle capacity factor sensitivity case are fuel, variable O&M, and replacement power. In the case of scenarios with a carbon price (scenarios B, D, F, and H), the cost of carbon emission allowances, CCS retrofit O&M, and transport/storage costs of CO_2 are also affected. The replacement power factor is a way of rewarding (or penalizing) over-performance (or under-performance) of the natural gas combined cycle plant if the resultant capacity factor is different than expected. When the capacity factor is below the 81% assumption, replacement power is required to be "purchased from the market" at the average cost of generation in the MROW electricity region (from the NEMS-MEC model), plus a 20% premium. This amount of replacement power purchased equals the difference between what the plant would generate at an 81% capacity factor and what it generates with a lower capacity factor. Similarly, if the capacity factor is higher than 81%, the plant "sells" the extra generation (generation in excess of an 81% capacity factor) at the average cost of generation in the MROW electricity region (without the 20% premium seen in the under-performance case).

This sensitivity case was not analyzed in-depth from a revenue requirement perspective since changing the capacity factor of a natural gas combined cycle unit has a minimal overall impact (see Figure 47). The primary reason for this is the cost savings or cost increases in fuel, O&M, and carbon credits mostly offsetting any decreased or additional revenue gains from selling power.

9. Decommissioning Costs

The requirements to decommission a nuclear generating unit are currently specified by the Nuclear Regulatory Commission ("NRC"), but the cost to comply with these requirements or possible change in the NRC requirements could result in different costs. NERA considered a range of costs from 90% of the base decommissioning cost assumption costs up to 150% of the base decommissioning cost assumption to reflect changes in decommissioning requirements.

This sensitivity case was not analyzed in-depth from a revenue requirement perspective since the decommissioning costs for nuclear generation are small and have a minimal overall impact (see Figure 47).

10. Sensitivity Analysis Summary and Results

The NERA analyses of the sensitivity of independent uncertain variables based on the cash flows for deploying nominal 2,400 MW of either natural gas combined cycle or nuclear SMR generating capacity demonstrate that changes in the assumptions for the discount rate and capital costs have the most significant impact on the present value of cash flows and revenue requirements. However, these are not added to the set of combinations of scenarios run through the integrated model. Instead, these additional uncertainties are used to flesh out the probability tree for the revenue requirements risk analysis by building on the eight foundational integrated sets of market projections. Although revenue requirements for both natural gas combined cycle and nuclear SMR generating options were examined in the risk analysis, NERA examined cash flows for the sensitivity analysis of independent uncertainties. The sensitivity of cash flows is used as a proxy for determining impact on revenue requirements and identifying which variables would be most significant.

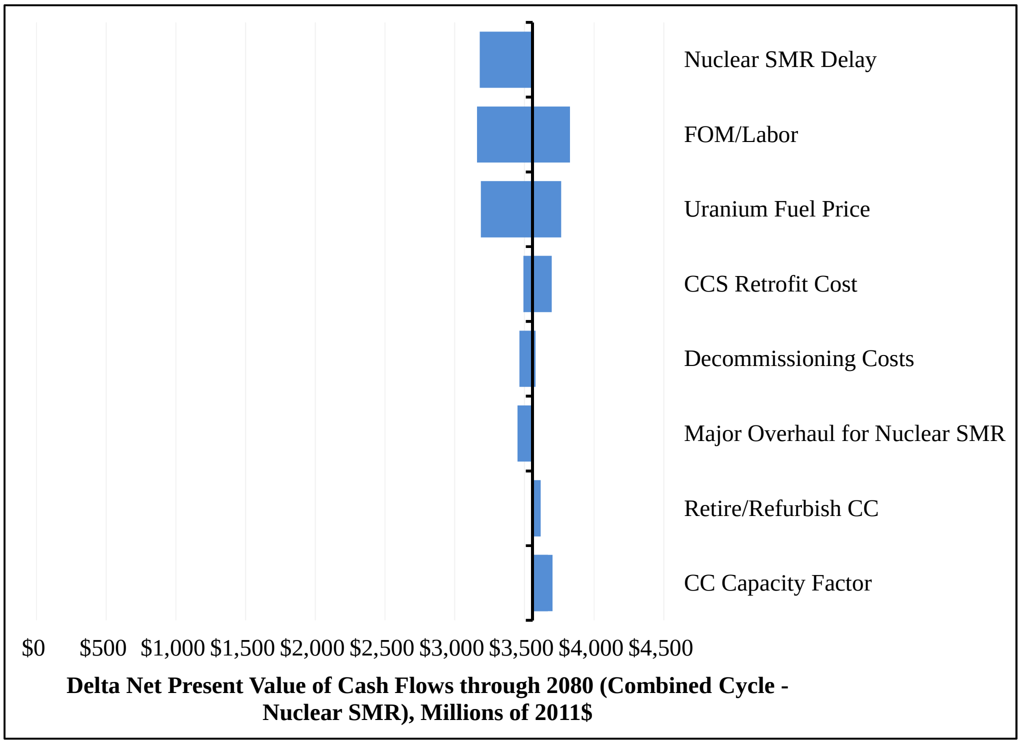
The assigned two- or three-level range of uncertainty – base, alternative 1, and alternative 2 discussed above for each of these independent uncertain variables, are summarized in Figure 46.

Figure 46: Summary of Sensitivities

Sensitivity	Base	Alternative 1	Alternative 2
Nuclear delay	No delay	2.5-year delay	NA
Retire/refurbish CC	Retire and replace after 30 years	Refurbish at 25% of cost of new after 30 years	NA
Uranium fuel prices	1.0% real annual growth	0.25% real annual growth	2.0% real annual growth
CCS retrofit cost	$1,000/kW	$500/kW	$2,000/kW
Nuclear major overhaul	None	NA	25% of cost of a new unit, starting in 2053
Labor/fixed O&M	100%	90%	115%
CC capacity factor	81%	70%	90%
Decommissioning costs	100%	90%	150%

The discounted cash flow impacts of each of the eight independent uncertain variables are shown in Figure 47. The figure is centered around a value of $3,560 million, which represents the probability-weighted average difference in the present value revenue requirements for the eight energy market scenarios without any sensitivities.

Figure 47: Tornado Diagram of Sensitivity Results



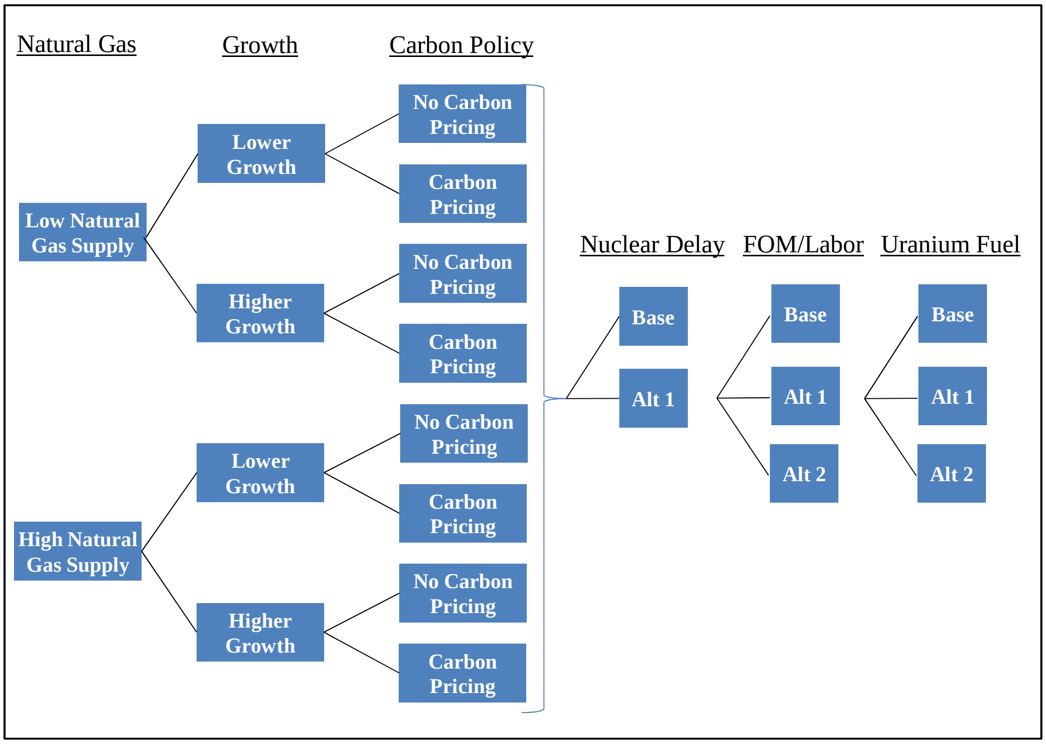
After capital costs and discount rates (addressed separately and therefore not shown in the figure), the next most significant independent uncertainties were nuclear delay, changes in fixed O&M and labor, and changes in the price of uranium. These were the independent uncertainties that NERA decided, based on the sensitivity analysis results summarized in Figure 47, to add to the full probability tree and incorporate into the risk analysis.

E. Risk Analysis

1. Independent Uncertainties included in Risk Analysis

The three most significant independent uncertainties shown in Figure 47 (*i.e.*, nuclear delay, fixed O&M and labor, and uranium fuel prices) were added to the full probability tree as shown in Figure 48. The addition of these variables to the original eight energy market scenarios produces 144 different combinations. The difference in the present value of revenue requirements associated with adding a natural gas combined cycle or a nuclear SMR deployment was calculated for each of the 144 different combinations.

Figure 48: Full Probability Tree Used for Risk Analysis



2. Discount Rates

For the discount rate, NERA examined potential alternatives for how a discount rate could be used to evaluate these types of projects and how that discount rate could be calculated. The alternative discount rate considered is a societal discount rate similar to what has previously been used by the Iowa utility regulator in its evaluation of energy efficiency programs. While this type of discount rate has not been used in filings for supply-side rate making principles, NERA wanted to examine the impact an alternate rate would have on results.

NERA started with a societal discount rate used for the 2014 through 2023 Iowa Statewide Assessment of Energy Efficiency of 3.56%.[83] Since this is a nominal rate, NERA converted it into a real rate (in line with all the other calculations) by removing inflation expectations implied by the spreads between Treasury Bond rates and inflation-indexed Treasury Bond rates in the same time period over which the societal discount rate was calculated. The resulting real societal discount rate was 1.36% and is used in the alternate discount rate evaluation.

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83 See reference to this at: http://puc.sd.gov/commission/dockets/gas&electric/2012/GE12-005/exhibit4.pdf.

3. Risk Analysis Results

To perform a risk analysis for the full probability tree, it was necessary to assign probabilities to the alternative potential outcomes for each of the sensitive independent uncertainties.

The alternative values and assignment of probabilities for each value were based on NERA's industry expertise. As discussed in the previous section, NERA believes there is slightly more potential for higher costs than lower costs in regards to the fixed O&M/labor, and this is reflected in a high value that is 15% above the base value and a low value that is 10% below the base value. Without detailed cost estimates NERA assumed a normal distribution around the base value with 50% of the probability associated with the base value and 25% probability associated with each of the two alternative values.

NERA's nuclear subject matter expert developed the uranium fuel price forecasts. As a commodity product, NERA recognizes the potential for annual volatility, but concluded the alternative fuel forecasts were best represented by different rates of growth, with a higher cost forecast growing at 2.0% per year and a lower price forecast growing at 0.25% per year (and the base case forecast growing at 1.0% per year). The NERA expert assigned 50% probability to the base value and 25% probability to each of the two alternative values.

Lastly, NERA assumed a 2.5 year nuclear delay as a potential alternative. The details behind this potential delay were discussed above. NERA assigned a 75% probability to no delay (the base assumption) and a 25% probability to a 2.5 year delay.

Figure 49 summarizes the alternative potential values and the probabilities assigned to each of these uncertain variables.

Figure 49: Summary Probabilities for Sensitive Independent Uncertainties

Independent Uncertainty		Base	Alternative 1	Alternative 2
Fixed O&M/ Labor	Value	MidAmerican values for nuclear; EIA for natural gas combined cycle	90% of Base values	115% of Base values
	Probability	50%	25%	25%
Uranium Fuel Price	Value	Prices grow at 1.0%/year	Prices grow at 0.25%/year	Prices grow at 2.0%/year
	Probability	50%	25%	25%
Nuclear Delay	Value	No delay	2.5-year delay	NA
	Probability	75%	25%	NA

Adding the probabilities of the sensitive independent uncertainties completes the information required to construct a CDF of the differences in present value revenue requirements for deployment of new natural gas combined cycle relative to nuclear SMRs.

Figure 50 shows the CDF for the period from 2012 to 2080.[84] The x-axis of the CDF is the present value of the revenue requirements associated with deploying 2,400 MW of natural gas combined cycle less the present value of the revenue requirements associated with deploying 2,400 MW (nominal) of nuclear SMR. Thus, a positive number denotes that the present value of revenue requirements for a natural gas combined cycle are higher than those for nuclear, and vice versa. The CDF indicates there is about 20% probability that deploying natural gas combined cycle will be less costly than deploying nuclear SMR in Iowa, and about 80% probability that deploying nuclear SMR will be less costly than deploying natural gas combined cycle.

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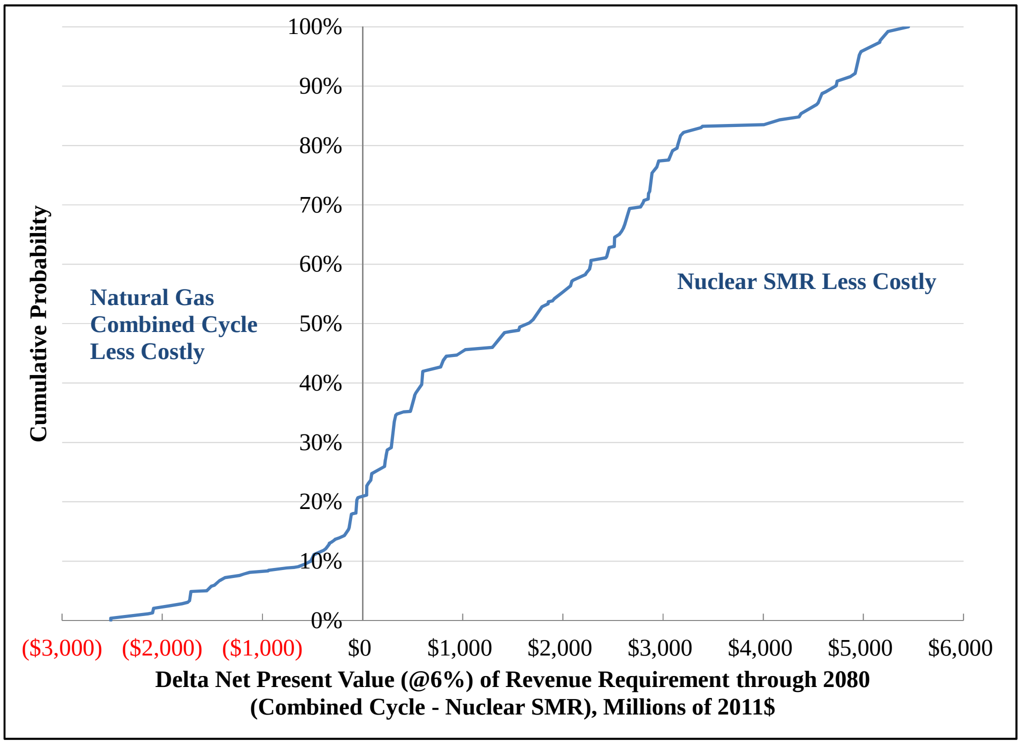
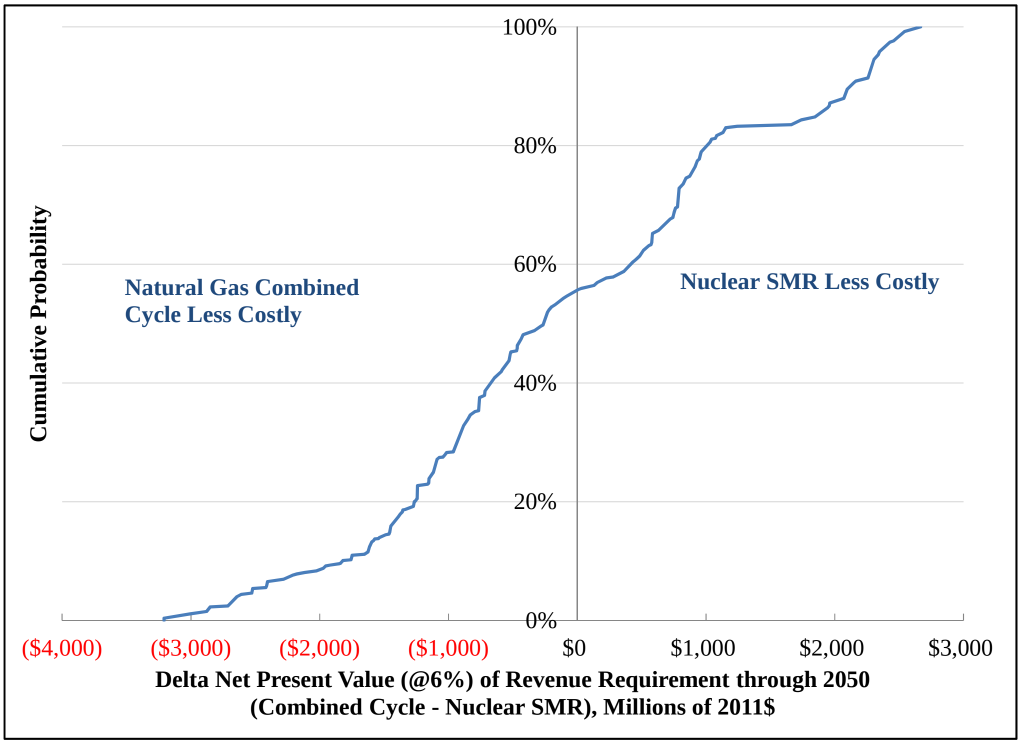
[84] The relevant time period of evaluation is over the life of the longer-lived asset, the nuclear generating unit, which is 60 years beginning in 2020. The reason the comparison begins in 2012 is that some costs for the nuclear deployment begin in 2012 and if the evaluation period were to not begin until 2020 then significant costs would not be captured.

Figure 50: Cumulative Distribution Function of the Differences in Present Value Revenue Requirements, Natural Gas Combined Cycle less Nuclear SMR, 2012-2080



While it is most appropriate to evaluate the relative costs of natural gas combined cycle and nuclear SMR over a 60-year period to capture the full life of the nuclear unit, it can also be informative to evaluate these over a shorter time period. Figure 51 shows the CDF for the period 2012 through 2050. As expected, the probability that natural gas combined cycle performs better than nuclear SMR over this shorter time horizon is increased, to about 55%. This is because operating costs for natural gas combined cycle such as fuel and emissions allowances are generally increasing over time, while the largest cost for the nuclear deployment is capital, which is being slowly recovered over the entire life of the units (as seen in Figure 37).

Figure 51: Cumulative Distribution Function of the Differences in Present Value Revenue Requirements, Natural Gas Combined Cycle less Nuclear SMR, 2012-2050[85]



4. Discount Rate

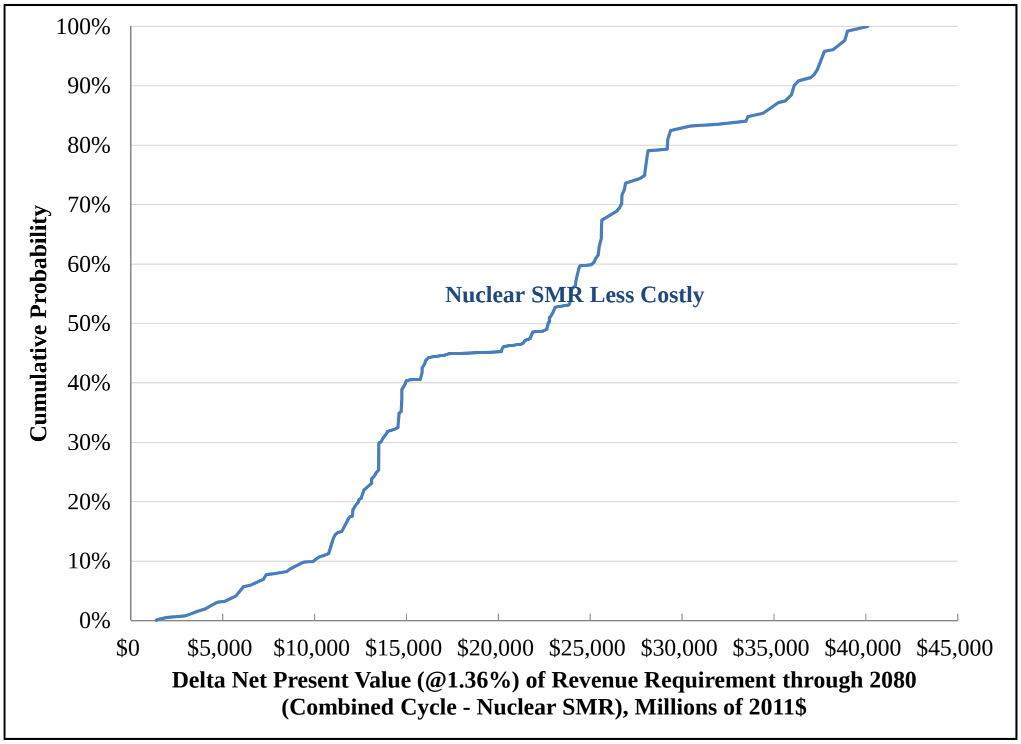
In the calculation of present value of cash flow costs and revenue requirements, the base real discount rate is 6%. This discount rate is the value provided by MidAmerican and represents the company's forecasted real weighted average cost of capital ("WACC") adjusted for a 2.5% inflation rate.

NERA also evaluated the impact of the discount rate on the CDF using the real societal discount rate of 1.36% described in Section V.E.2. The real 6% discount rate is used as the base assumption in the analysis because WACC is usually used for discounting utility investment decisions. However, it can be useful to examine the sensitivity of the calculations to this factor. Figure 52 shows the CDF for the 1.36% discount factor. This estimate may also be appropriate for discounting revenue requirements because future electricity rates will be borne by customers, and this discount factor estimates the real social rate of discount. As expected, nuclear SMR performs exceptionally better in the lower discount rate case due to its higher share of costs in the near term (capital costs) relative to natural gas combined cycle deployment which has higher

85 The shorter time period included in the figure includes the same costs in the same years as in Figure 50. As such, the nuclear SMR costs are still assumed to be recovered over the period through 2080.

costs during the end of the study period (as seen in Figure 37). In fact, with the lower discount rate, the SMR option has lower present value of revenue requirements with 100% probability.

Figure 52: Cumulative Distribution Function of the Differences in Present Value Revenue Requirements, Natural Gas Combined Cycle less Nuclear SMR, 2012-2080 with Alternate Discount Rate



VI. IOWA ECONOMIC DEVELOPMENT ANALYSIS

While revenue requirements provide insight into the cost recovery from customers, the assessment of local and state economic development impacts also utilize the project annual cash flows in the local region. The cash flow analysis utilizes the annual cash outlays, while the revenue requirement analysis utilizes the annual revenue requirement from customers, and discounts them back to a present value for comparison.

A. Section Findings

NERA assessed the Iowa economic development, or macroeconomic, impacts for the nuclear SMR and natural gas combined cycle deployment options using the nationally-recognized REMI PI+ model. The inputs for the REMI PI+ model include the estimates of the types and locations of the cash flows associated with the alternative baseload generation deployments and the resulting revenue requirements impact on Iowa electricity and natural gas rates.

The deployment of nuclear and natural gas generation has fundamental differences in the allocation of costs over the project lifetime, which directly impacts economic development in Iowa. These differences include:

- Higher on-site employment at a nuclear site,
- Lower fuel costs for a nuclear deployment, which result in lower payments to entities outside Iowa that supply the fuel, and
- Differential Iowa electricity rates over the period through 2080 for the nuclear SMR and natural gas combined cycle deployments.

The economic development benefits to Iowa are more positive for a nuclear SMR deployment compared to a natural gas combined cycle deployment for all eight of the energy market scenarios.

B. Background and Approach

NERA assessed the macroeconomic impacts on the state of Iowa through an economic development analysis. This analysis utilizes results from the cash flow analysis, which are then used as inputs in the REMI PI+ model.[86] The REMI PI+ model produces estimates of the changes in GSP, employment, personal labor income, and other macroeconomic variables due to changes in supply, demand, prices, and other types of inputs.

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[86] Additional details about the REMI PI+ model are included in Appendix B.

The version of the REMI PI+ model used for this analysis was custom-built for the regions of interest. This version includes three regions: 1) Iowa, 2) Rest of Upper Midwest – Wisconsin, Illinois, Missouri, Kansas, Nebraska, South Dakota, North Dakota and Minnesota, and 3) Rest of the U.S. This version of the model represents all industrial inputs and outputs across the economy disaggregated to 70 separate sectors. The modeling horizon for the model extends through 2060.

For purposes of presenting results, the analysis compares macroeconomic outcomes associated with a nuclear SMR deployment in Iowa relative to a natural gas combined cycle deployment.

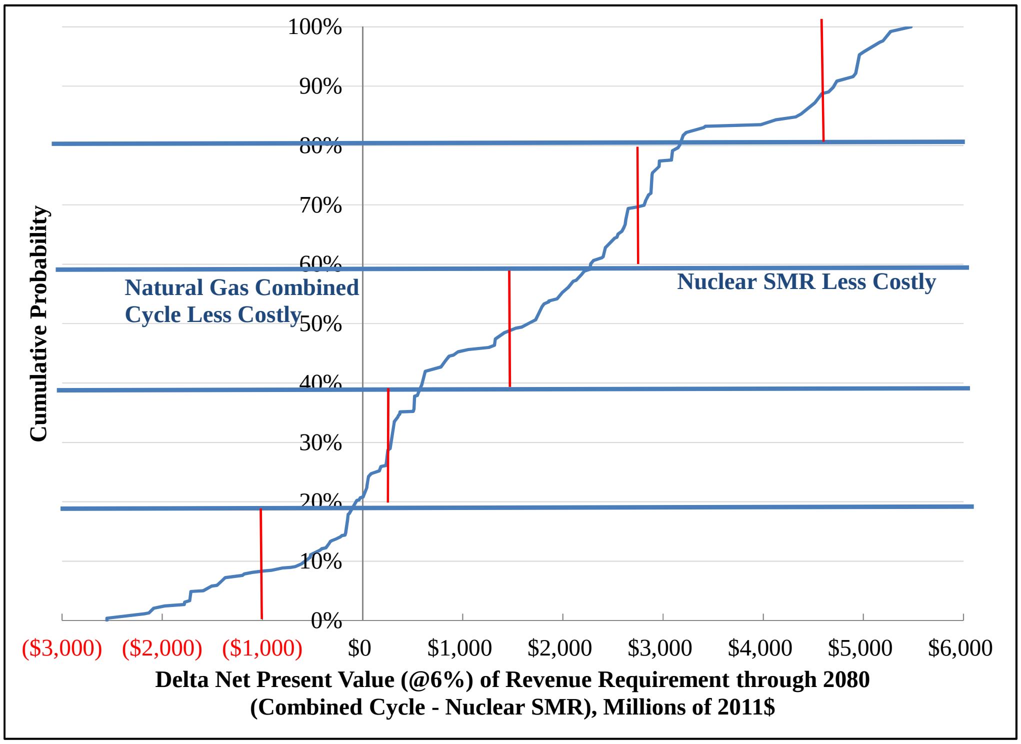
C. Cases Evaluated in REMI PI+

The inputs into the REMI PI+ model are results from the cash flow and revenue requirements analysis. The cash flow and revenue requirements analysis had 144 different outcomes for both a nuclear SMR and a natural gas combined cycle deployment, making it necessary to select a subset of outcomes for evaluation in the REMI PI+ model.

To begin, NERA evaluated each of the eight energy market scenarios with all the independent uncertainties set at their base case levels. These eight scenarios are used to provide some initial information about the macroeconomic impacts on the state of Iowa.

To expand on the initial eight energy market scenarios, and to link to the CDF revenue requirement chart that includes uncertainties in other variables, NERA identified a representative set of five scenarios for evaluation in the REMI PI+ model. NERA reviewed the details of the CDF results (see Figure 50), and then divided the distribution into five even blocks of probability results – 0% to 20%, 20% to 40%, 40% to 60%, 60% to 80%, and 80% to 100%. Within each block a mid-point was selected that represented the approximate point where the probability-weighted outcomes above and below the mid-point were equal within the block. This is represented in Figure 53, where the horizontal (blue) lines separate the distribution into blocks and the vertical (red) lines represent the mid-point within each block.

Figure 53: Cumulative Distribution Function of the Differences in Present Value Revenue Requirements, Natural Gas Combined Cycle less Nuclear SMR, 2012-2080, with Block Representation



NERA evaluated the characteristics of the outcomes near the mid-point within each block. These characteristics included the scenario (scenarios A through H) and the sensitive independent uncertainties (nuclear delay, uranium fuel price, and fixed O&M/labor).

Figure 54: Characteristics of Outcomes Evaluated in REMI PI+ Model

	Block	Scenario	Nuclear Delay	Uranium Fuel Price	Fixed O&M/Labor
1	0 - 20%	E	Yes	Low	Low
2	20 - 40%	A	No	High	Low
3	40 - 60%	H	Yes	Low	High
4	60 - 80%	C	Yes	Low	High
5	80 - 100%	D	No	Base	High

Given the importance of capital expenditures in the REMI PI+ model, specific attention was paid to the nuclear capital cost. To address this, NERA evaluated the same five scenarios assuming two different levels of EPC capital costs.[87] The alternative levels of EPC capital expenditures by the EPC contractor are $6,490/kW and $11,991/kW. These alternative levels of EPC capital costs were based on a distribution of FOAK EPC capital costs elicited from NERA's nuclear technology expert.

NERA did not evaluate a discount rate sensitivity in the REMI PI+ model. While it would change the magnitude of any present value results, it would not change the relative ranking of results or the ultimate conclusions from the analysis.

D. Inputs

The inputs into the REMI PI+ model are the annual expenditures and natural gas rates that are calculated in the cash flow analysis and the electricity rates that are calculated in the revenue requirement analysis. An important aspect of these expenditures is where the purchases take place. For example, spending in Iowa produces different macroeconomic impacts for the state of Iowa than if the same expenditures were made in California. The allocation of the expenditures to Iowa and the other regions is based primarily on analyses provided by MidAmerican as received from the nuclear SMR vendors.

1. Nuclear

The version of the REMI PI+ model used in this analysis includes 70 economic sectors to represent all industrial inputs and outputs. The expenditures for constructing and operating the nuclear SMR plant enter the REMI PI+ model as sales for two sectors: 1) Machinery Manufacturing and 2) Construction. In particular, the portion of each expenditure category representing equipment enters the REMI PI+ model as sales for the Machinery Manufacturing sector, while the portion of each expenditure category representing labor (*i.e.*, labor to construct the nuclear plant at its site rather than labor to produce the equipment) enters the REMI PI+ model as sales for the Construction sector. The allocations of expenditures associated with the nuclear deployments are based primarily on a memo produced for MidAmerican by a small nuclear SMR vendor.[88]

The changes in sales are allocated among the three regions in the model (Iowa, Rest of Upper Midwest, and Rest of U.S.) based on estimates of local (*i.e.*, in-state) vs. non-local (*i.e.*, out-of-state) supply for the major expenditure categories. Non-local supply is allocated between Rest of Upper Midwest and Rest of U.S. based on the two regions' shares of their collective gross

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87 As discussed above, the higher costs are incurred by the vendors and reflect higher spending levels in Iowa to construct the nuclear unit, but do not imply higher costs to MidAmerican or its customers.

88 "MEC Request for Annual On-Site Construction Costs for (vendor name withheld)," June 16, 2011, and Memo from (vendor name withheld), August 7, 2012 (Response Re: to MEC Request for Construction Cost Data), with a separate Excel attachment.

regional product. Thus, 12% of non-local supply for both equipment and labor is allocated to Rest of Upper Midwest, and the remaining 88% of non-local supply is allocated to Rest of U.S.

Figure 55 shows the allocation of each expenditure category for constructing and operating the nuclear plant to the Machinery Manufacturing and Construction sectors. The figure also shows the allocation to Iowa, Rest of Upper Midwest, and Rest of U.S. within the two sectors. Note that no expenditure category involves out-of-state labor directly because the out-of-state Machinery Manufacturing sector already accounts for the labor requirements to produce the equipment. Note too that four expenditure categories - 1) Fixed O&M/Labor, 2) Fuel Disposal, 3) Relicensing, and 4) Decommissioning - are modeled entirely as sales for Iowa's Construction sector.

The expenditure category of Replacement Power is only applicable in scenarios that include nuclear delay, since MidAmerican would need to purchase replacement power to meet its load as a substitute for the generation not available from the nuclear SMR generator. It is assumed that the replacement power will all come from surrounding states (Rest of Upper Midwest). The 88% allocation to Machinery Manufacturing and the 12% allocation to the Construction sector is the same split used for the natural gas combined cycle capital costs (see Figure 56).

Figure 55: Allocations for Nuclear SMR Expenditures in REMI PI+ Model

	Machinery Mfg (Equipment)				Construction (Labor)			
		Out-of-State				Out-of-State		
Expenditure Category	Iowa	Total	Upper MW	Rest of U.S.	Iowa	Total	Upper MW	Rest of U.S.
Capital (EPC)	8%	54%	7%	47%	38%	0%	0%	0%
Post-COD CAPX	17%	0%	0%	0%	83%	0%	0%	0%
Owner's Cost	23%	39%	5%	35%	38%	0%	0%	0%
Fixed O&M/Labor	0%	0%	0%	0%	100%	0%	0%	0%
Fuel Disposal	0%	0%	0%	0%	100%	0%	0%	0%
Relicensing	0%	0%	0%	0%	100%	0%	0%	0%
Replacement Power	0%	88%	88%	0%	0%	12%	12%	0%
Decommissioning	0%	0%	0%	0%	100%	0%	0%	0%

In addition to the expenditure categories shown in Figure 55 for constructing and operating the nuclear SMR plant, the cash flow analysis also includes expenditures for nuclear fuel. These nuclear fuel expenditures enter the REMI PI+ model as demand in Iowa for products from the Mining sector. Since almost all of Iowa's demand for products from the Mining sector is met by out-of-state suppliers, the REMI PI+ model recognizes that the economic activity associated with mining and processing the nuclear fuel would occur almost entirely outside of Iowa.

2. Natural Gas Combined Cycle

The expenditures for constructing and operating the natural gas combined cycle plants enter the REMI PI+ model in a manner similar to the expenditures for the nuclear SMR plant. The cash flow analysis uses six expenditure categories for the natural gas combined cycle plants. The portion of each expenditure category representing equipment enters the REMI PI+ model as sales for the Machinery Manufacturing sector, while the portion of each expenditure category representing labor (*i.e.*, labor to construct the natural gas combined cycle plants at their sites rather than labor to produce the equipment) enters the REMI PI+ model as sales for the Construction sector. The allocations of expenditures associated with the natural gas combined cycle deployment are based primarily on a spreadsheet provided by MidAmerican to NERA.[89] NERA allocated non-local supply between Rest of Upper Midwest and Rest of U.S. based on their GDPs in the same manner as for expenditures in the nuclear deploy plan.

Figure 56 shows the allocation of each expenditure category for constructing and operating the natural gas combined cycle plants to the Machinery Manufacturing and Construction sectors. The figure also shows the allocation to Iowa, Rest of Upper Midwest, and Rest of U.S. within the two sectors. Note that expenditures for variable O&M and fixed O&M are allocated entirely to the local Construction sector.

[89] Nominal 500 MW CCCT Project Cost Summary 030712.xls, Reference: Sega Project Cost Summary, GE 7AF 2X1 486 nameplate CCGT; via Spencer Moore, March 5, 1012.

Figure 56: Allocations for Natural Gas Combined Cycle Expenditures in REMI PI+ Model

Expenditure Category	Machinery Mfg (Equipment)				Construction (Labor)			
	Iowa	Out-of-State			Iowa	Out-of-State		
		Total	Upper MW	Rest of U.S.		Total	Upper MW	Rest of U.S.
Capital (including owner's costs)	16%	72%	9%	63%	12%	0%	0%	0%
Variable O&M	0%	0%	0%	0%	100%	0%	0%	0%
Fixed O&M	0%	0%	0%	0%	100%	0%	0%	0%
CCS Retrofit	16%	72%	9%	63%	12%	0%	0%	0%
CCS Retrofit O&M/ Transport/Storage	16%	72%	9%	63%	12%	0%	0%	0%

In addition to the expenditure categories shown in Figure 56 for constructing and operating the natural gas combined cycle units, the cash flow analysis also includes expenditures for natural gas. These fuel expenditures enter the REMI PI+ model as demand in Iowa for products from the Oil and Gas Extraction sector. Since almost all of Iowa's demand for products from the Oil and Gas Extraction sector is met by out-of-state suppliers, the REMI PI+ model recognizes that the economic activity associated with producing natural gas would occur almost entirely outside Iowa.

3. Electricity Rates

The REMI PI+ model uses indices to track prices for electricity and other commodities. These indices incorporate both general inflation and real changes in price levels. The indices begin in past years and extend to the end of the modeling period (2060).

Inputs related to prices enter the REMI PI+ model as proportional differences from baseline price levels built into the model. Thus, the two main steps for entering electricity rate impacts into the REMI PI+ model are 1) determine the REMI PI+ model's built-in baseline electricity rates; and 2) determine the proportional changes from these baseline electricity rates for the nuclear and natural gas combined cycle deployment plans.[90]

[90] The baseline information in the REMI PI+ model is not used beyond what has been described here and has no impact on the results, which are a comparison of macroeconomic results in Iowa when deploying new nuclear SMR relative to deploying new natural gas combined cycle.

The index for electricity rates in the REMI PI+ model can be converted to price levels (*e.g.*, 2011 cents per kWh) using the price level in a historical year and the index value for that historical year. Index values for future years then provide the basis for scaling the historical price level into future price levels. NERA used information on average retail electricity prices in Iowa in 2010 from the U.S. EIA to convert the REMI PI+ model's electricity price index into cents per kWh in future years. Using electricity rate forecasts for Iowa for the nuclear and natural gas combined cycle deployment plans from the cash flow analysis, NERA then calculated differences from the REMI model's built-in price forecasts in proportional terms.

NERA entered these proportional differences in electricity rates into the REMI PI+ model for households, commercial sectors, and industrial sectors in Iowa. All three of these groups are assumed to have the same proportional differences in electricity rates from the REMI PI+ model's built-in baseline values. NERA assumed that electricity rates would be the same as the REMI PI+ model's built-in baseline values for Rest of Upper Midwest and Rest of U.S., so electricity rates in these other regions were not adjusted.

4. Natural Gas Prices

NERA adjusted natural gas prices in the REMI PI+ model in a manner similar to electricity rates. The REMI PI+ model also has an index for natural gas prices. NERA first converted this index into price levels (*e.g.*, 2011$ per MMBtu) for future years using historical information on the average natural gas price in Iowa in 2010 from the U.S. EIA. These calculated natural gas prices were used for the nuclear SMR and natural gas combined cycle deployment plans (the same natural gas prices calculated in the revenue requirement analysis).

NERA entered these proportional differences in natural gas prices into the REMI PI+ model for households, commercial sectors, and industrial sectors in Iowa. All three of these groups are assumed to have the same proportional differences in natural gas prices from the REMI PI+ model's built-in baseline values. NERA assumed that natural gas prices would be the same as the REMI PI+ model's built-in baseline values for Rest of Upper Midwest and Rest of U.S., so natural gas prices in these other regions were not adjusted.

The natural gas price differences are a very small factor because the only differences in natural gas demand between the two scenarios being compared is from the natural gas consumed by the 2,400 MW of new natural gas combined cycles built in Iowa. This is a very small share of total U.S. natural gas demand and therefore only translates to a few cents difference in natural gas prices.

5. Timing

As noted above, the REMI PI+ model can take inputs and produce economic impacts through 2060. To incorporate the information from the cash flow analysis that extends to 2080, NERA calculated the average expenditures from 2060 through 2080 and used this average value in 2060. Thus, results in 2060 reflect the average impact of expenditures from 2060 through 2080.

The outputs for 2060 were then assumed to be the same for the years 2061 through 2080. Present values and sums of annual results from the REMI PI+ model therefore reflect the timing of expenditures and impacts through 2080.

E. Results

The REMI PI+ model produces a range of results for each year. The key results for the state of Iowa are the GSP, total employment, and disposable personal income. The GSP is a measure of the value added across all sectors in the state of Iowa and is reflective of the overall productive activity of the state's economy. Total employment in Iowa is directly related to the GSP as increased value added generally implies increased employment. Total employment includes both full-time and part-time employment (at equal weight). Lastly, disposable personal income is a reflection of the economic wellbeing of households in Iowa as it represents personal income less personal taxes for the state as a whole.

The expenditure inputs to the REMI PI+ model generate positive economic impacts because the expenditures circulate throughout the economy and induce economic activity in sectors that indirectly support the sectors with increased demand (such as Machinery Manufacturing and Construction). A scenario with higher electricity and natural gas price inputs to the model, on the other hand, typically generates negative economic impacts because higher electricity and natural gas prices increase production costs for businesses (hurting their competitiveness) and lower purchasing power for households (though the increased revenue to electricity and natural gas suppliers can partially offset these negative effects). Thus, scenarios with larger expenditures and relatively low electricity and natural gas prices have larger positive economic impacts. Deploying new nuclear SMRs would involve larger expenditures and lower natural gas prices than deploying new natural gas combined cycle. Electricity rates may be higher or lower, depending on the scenario. Moreover, the expenditures required in order to deploy new nuclear SMR generation would occur earlier (and thus contribute more on a present value basis) than the expenditures to deploy new natural gas combined cycle generation. As a result, deploying new nuclear SMR would generally lead to larger positive economic impacts in Iowa than deploying new natural gas combined cycle.

Figure 57 includes the macroeconomic results for Iowa that result from deploying new nuclear SMR instead of new natural gas combined cycle capacity in Iowa for the original eight energy market scenarios with all other variables set to their base values. For each of the eight energy market scenarios, the figure also shows the average natural gas price, the average annual increase in electricity demand and the 2020 CO_2 price as a means of quantifying some of the relevant characteristics of each scenario. Figure 57 shows:

- Iowa's GSP increases from deploying new nuclear SMR instead of new natural gas combined cycle capacity in Iowa.
- The presence of a price on CO_2 increases the relative gains in Iowa GSP from deploying new nuclear by $1 to $2 billion dollars over the period from 2012 through 2080.

- Lower natural gas prices (with similar demand and CO_2 prices), diminish the relative benefits of deploying new nuclear by \$3 to \$4 billion dollars over the same period (this can be seen by comparing the following scenarios A-E, B-F, C-G and D-H).

- Average annual employment in Iowa increases from deploying new nuclear instead of new natural gas combined cycle capacity in Iowa for the eight base energy market scenarios.

- Similar to the effect of CO_2 prices on Iowa GSP, the presence of a CO_2 price increases the relative employment gains for nuclear deployments as opposed to natural gas combined cycle deployments by 1,000 to 3,000 jobs per year from 2012 through 2080.

- Lower natural gas prices (with similar demand and CO_2 prices) lower the relative benefits of deploying new nuclear by 2,000 to 3,000 jobs per year over the same period (this can be seen by comparing the following scenarios A-E, B-F, C-G, and D-H).

- Disposable personal income for Iowa residents increases when nuclear is deployed instead of natural gas combined cycle. The level of increase in disposable personal income is similar to the increases in GSP.

Figure 57: Macroeconomic Results in Iowa Associated with Deploying New Nuclear SMR Instead of New Natural Gas Combined Cycle – Eight Energy Market Scenarios (No Sensitivities) (All dollar values in 2011$)

Scenario Characteristics				Macroeconomic Results		
Scenario	Avg. Henry Hub Price ($/MMBtu) for 2012-2080	Avg. Electricity Demand Growth Rate 2012-2080	CO_2 Price ($/ metric ton) in 2020	Present Value Increase in Iowa GSP (Millions) for 2012-2080	Increased Average Annual Employment in Iowa (Jobs) 2012-2080	Present Value Increase in Iowa Disposable Personal Income (Millions) for 2012-2080
A	$10.77	0.4%	$0	$5,336	7,039	$4,922
B	$10.46	0.3%	$20	$8,786	9,932	$7,104
C	$14.97	1.2%	$0	$6,744	7,396	$5,775
D	$13.53	1.0%	$20	$8,435	8,365	$6,813
E	$8.64	0.5%	$0	$2,358	5,109	$3,055
F	$7.60	0.4%	$20	$4,584	6,657	$4,454
G	$11.08	1.1%	$0	$3,625	5,269	$3,813
H	$9.94	1.0%	$20	$5,705	6,778	$5,096
Probability Weighted Average				$6,088	7,303	$5,373

Energy Market Scenario	A	B	C	D	E	F	G	H
Natural Gas Supply	Low	Low	Low	Low	High	High	High	High
Economic Growth	Low	Low	High	High	Low	Low	High	High
Carbon Price	No	Yes	No	Yes	No	Yes	No	Yes
Probability	23%	10%	17%	17%	8%	8%	5%	12%

Figure 58 includes the Iowa macroeconomic results from deploying nuclear relative to natural gas combined cycle capacity in Iowa for five scenarios that represent different points along the CDF of the difference in revenue requirements shown in Figure 53. The figure also shows the scenario characteristics. Figure 58 shows:

- Iowa's GSP increases from deploying new nuclear SMR instead of new natural gas combined cycle capacity in Iowa for five energy market scenarios that represent different points along the CDF as shown in Figure 53. Not surprisingly, as the probability that nuclear SMR deployment is less costly than natural gas combined cycle increases, Iowa's GSP also increases.

- Average annual employment in Iowa increases as the scenarios have a higher probability that nuclear SMR deployment is less costly than natural gas combined cycle for the five scenarios that represent different points along the CDF as shown in Figure 53.

- Disposable personal income in Iowa increases for the energy market scenarios that have a higher probability that nuclear SMR deployment is less costly when compared to natural gas combined cycle.

Figure 58: Macroeconomic Results in Iowa Associated with Deploying Nuclear SMR Instead of Natural Gas Combined Cycle – Selected Scenarios with Sensitivities (All dollar values in 2011$)

Scenario Characteristics							Macroeconomic Results		
Scenario	Nuclear Delay	Uranium Fuel	FOM/ Labor	Avg. Henry Hub Price ($/MMBtu) for 2012-2080	Avg. Electricity Demand Growth Rate 2012-2080	CO_2 Price ($/metric ton) in 2020	Present Value Increase in Iowa GSP (Millions) for 2012-2080	Increased Average Annual Employment in Iowa (Jobs) 2012-2080	Present Value Increase in Iowa Disposable Personal Income (Millions) for 2012-2080
E	Delay	Low	Low	$8.64	0.5%	$0	$2,549	5,030	$2,908
A	No Delay	High	Low	$10.77	0.4%	$0	$4,976	6,444	$4,599
H	Delay	Low	High	$9.94	1.0%	$20	$5,243	6,644	$4,745
C	Delay	Low	High	$14.97	1.2%	$0	$6,385	7,279	$5,488
D	No Delay	Base	High	$13.53	1.0%	$20	$8,309	8,454	$6,863

Figure 59 includes the macroeconomic results for Iowa that result from deploying new nuclear instead of new natural gas combined cycle capacity in Iowa for five energy market scenarios that represent different points along the CDF as shown in Figure 53, assuming higher capital costs for deploying the new nuclear SMR (two different levels of capital costs). For each of the five scenarios, the figure also shows the average natural gas price, the average annual increase in electricity demand and the 2020 CO_2 price as a means of quantifying some of the relevant characteristics of each scenario. Figure 59 shows:

- Relative to the same energy market scenarios with the base nuclear SMR capital costs, the benefits to Iowa are larger as the higher capital costs represent more spending in Iowa, while the costs above the base nuclear SMR capital costs are borne by the manufacturer or government (not MidAmerican or its customers). The result that deviates from the pattern is the relative GSP for scenarios A and H with the highest nuclear SMR capital cost. The GSP is actually higher in scenario A and this is primarily attributable to the nuclear delay, which pushes back some of the additional spending within the state.

- Average annual employment in Iowa increases for the five energy market scenarios that represent different points along the CDF as shown in Figure 53. There is a similar pattern to the GSP results among these scenarios as well as a similar pattern relative to the base nuclear SMR capital cost scenarios.

- Disposable personal income in Iowa increases as the scenarios have a higher probability that nuclear SMR deployment is less costly. The exception to this pattern is with respect to scenarios A and H with the highest nuclear SMR capital cost. This exception is explained by the nuclear delay. Once again, as the nuclear SMR capital costs increase (and hence spending in Iowa increases), this becomes more beneficial to Iowa’s disposable personal income.

Figure 59: Macroeconomic Results in Iowa Associated with Deploying New Nuclear SMR Instead of New Natural Gas Combined Cycle – Selected Scenarios with Sensitivities, Higher Nuclear Capital Cost (All dollar values in 2011$)

Scenario Characteristics							Macroeconomic Results		
Scenario	Nuclear Delay	Uranium Fuel	FOM/ Labor	Avg. Henry Hub Price ($/MMBtu) for 2012-2080	Avg. Electricity Demand Growth Rate 2012-2080	CO_2 Price ($/ metric ton) in 2020	Present Value Increase in Iowa GSP (Millions) for 2012-2080	Increased Average Annual Employment in Iowa (Jobs) 2012-2080	Present Value Increase in Iowa Disposable Personal Income (Millions) for 2012-2080
Nuclear capital cost at 151% of Base Capital Costs									
E	Delay	Low	Low	$8.64	0.5%	$0	$3,342	5,477	$3,640
A	No Delay	High	Low	$10.77	0.4%	$0	$5,896	6,921	$5,455
H	Delay	Low	High	$9.94	1.0%	$20	$6,031	7,083	$5,471
C	Delay	Low	High	$14.97	1.2%	$0	$7,175	7,723	$6,217
D	No Delay	Base	High	$13.53	1.0%	$20	$9,223	8,921	$7,708
Nuclear capital cost at 279% of Base Capital Costs									
E	Delay	Low	Low	$8.64	0.5%	$0	$5,328	6,586	$5,471
A	No Delay	High	Low	$10.77	0.4%	$0	$8,188	8,081	$7,570
H	Delay	Low	High	$9.94	1.0%	$20	$8,012	8,189	$7,297
C	Delay	Low	High	$14.97	1.2%	$0	$9,153	8,826	$8,044
D	No Delay	Base	High	$13.53	1.0%	$20	$11,515	10,089	$9,831

APPENDIX A – Key Additional Results

The deployment of nuclear SMR and natural gas combined cycle generation has fundamental differences in the timing and composition of costs over the lifetime of each asset. These differences directly impact the economic development in Iowa.

Revenue requirements begin earlier for the nuclear SMR deployment because of the assumed recovery of AFUDC. However, during the later years of the study period revenue requirements are higher for the natural gas combined cycle deployment. While revenue requirements provide insight into the cost recovery from customers, the assessment of local and state economic development impacts also utilizes the timing of investment requirements in the local region.

Figure 60 through Figure 67 show a comparison of the revenue requirements between natural gas combined cycle and nuclear SMR deployments for each of the eight energy market scenarios. In general, the higher revenue requirements for the combined cycle deployment in later years result in a more heavily discounted cost to be recovered from the customers; however, the higher early year expenditures of the nuclear SMR deployment would result in greater positive economic development impacts in Iowa.

Figure 60: Annual Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment for Scenario A (Low Natural Gas Supply, Low Growth, No Carbon Pricing), 2012-2080 (2011$ Millions)

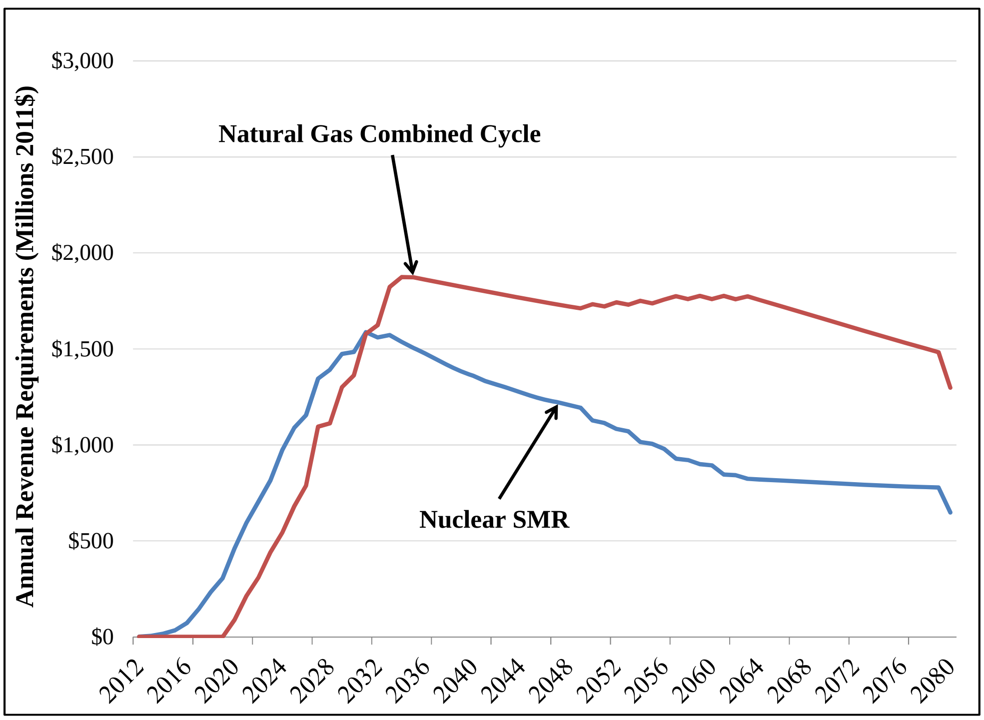


Figure 61: Annual Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment for Scenario B (Low Natural Gas Supply, Low Growth, Carbon Pricing), 2012-2080 (2011$ Millions)

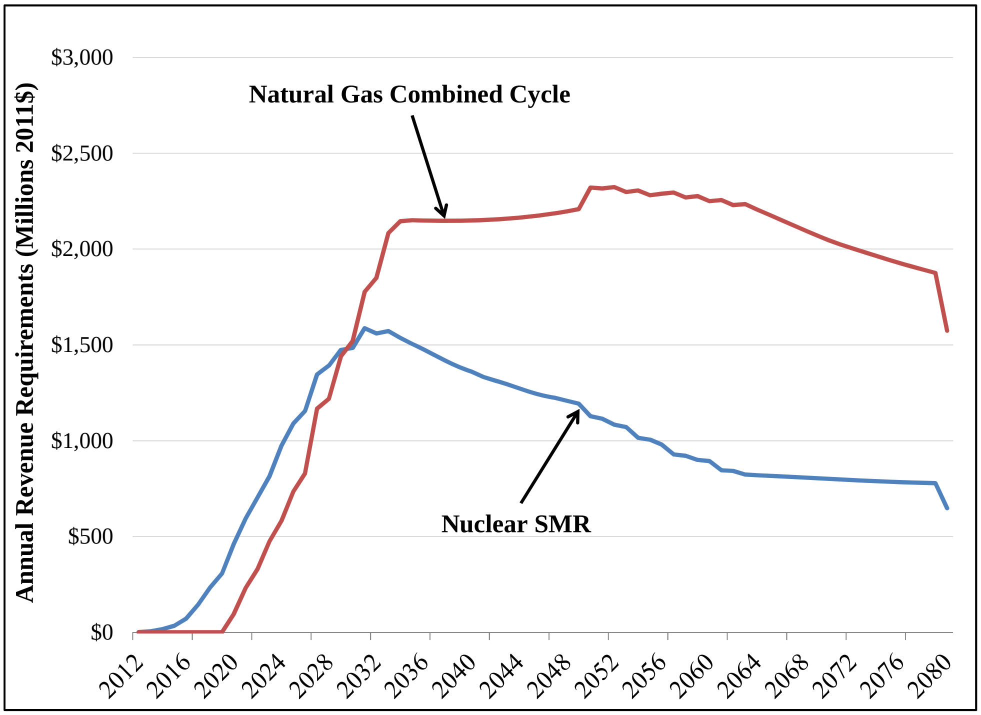


Figure 62: Annual Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment for Scenario C (Low Natural Gas Supply, High Growth, No Carbon Pricing), 2012-2080 (2011$ Millions)

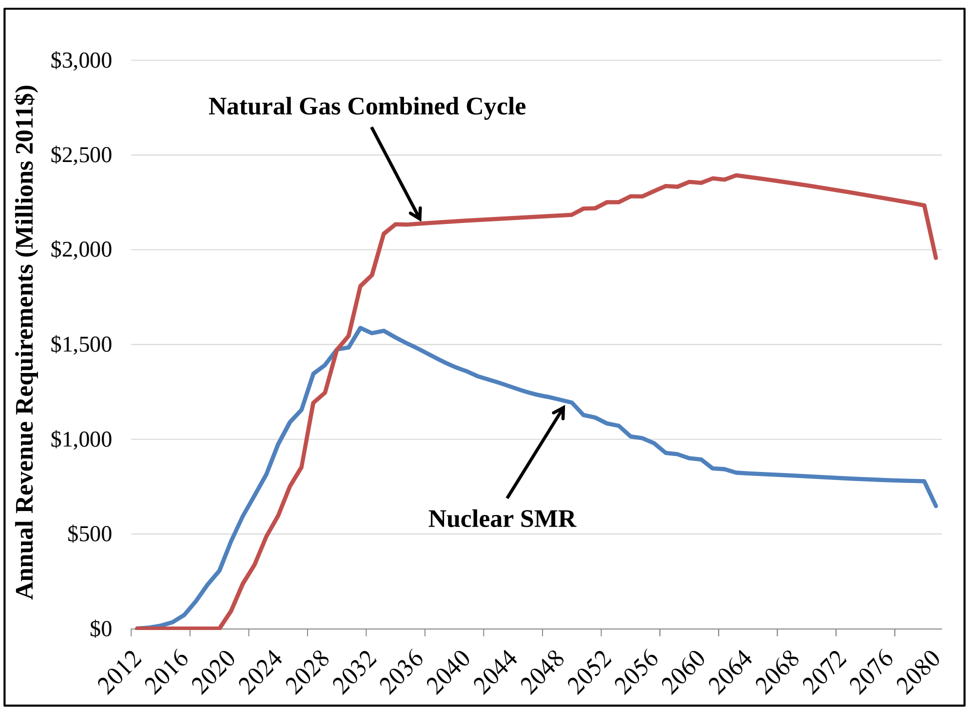


Figure 63: Annual Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment for Scenario D (Low Natural Gas Supply, High Growth, Carbon Pricing), 2012-2080 (2011$ Millions)

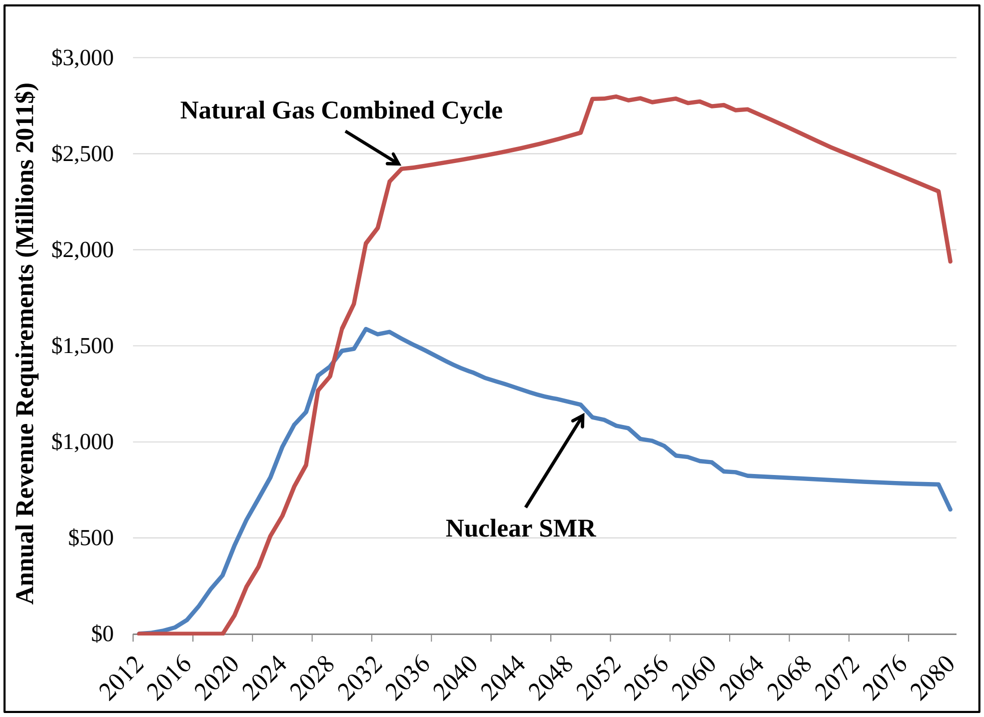


Figure 64: Annual Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment for Scenario E (High Natural Gas Supply, Low Growth, No Carbon Pricing), 2012-2080 (2011$ Millions)

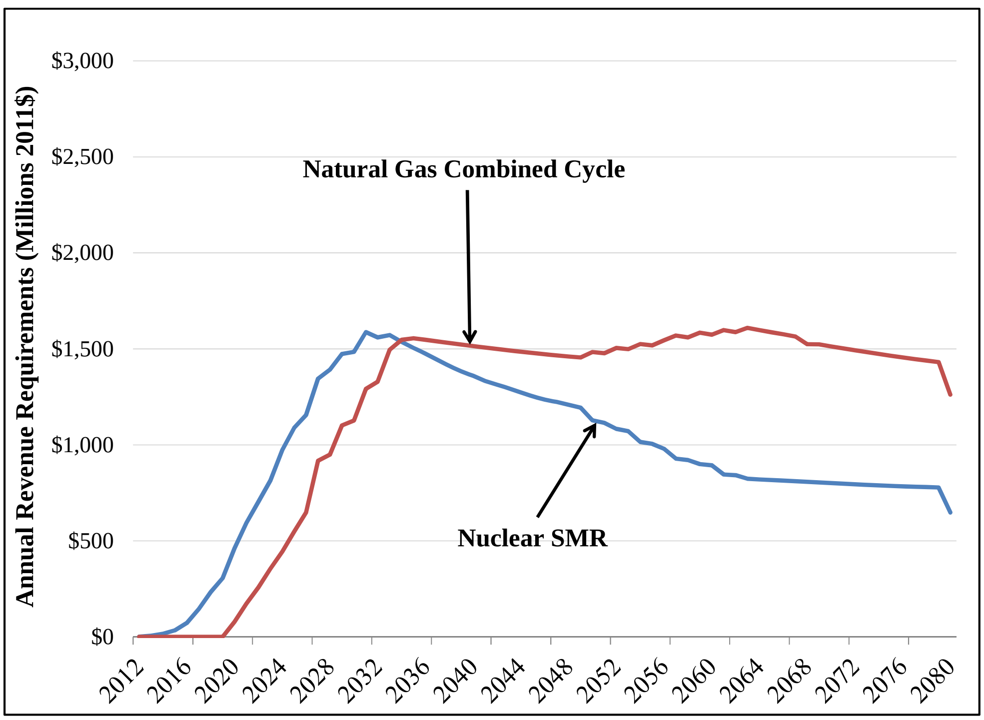


Figure 65: Annual Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment for Scenario F (High Natural Gas Supply, Low Growth, Carbon Pricing), 2012-2080 (2011$ Millions)

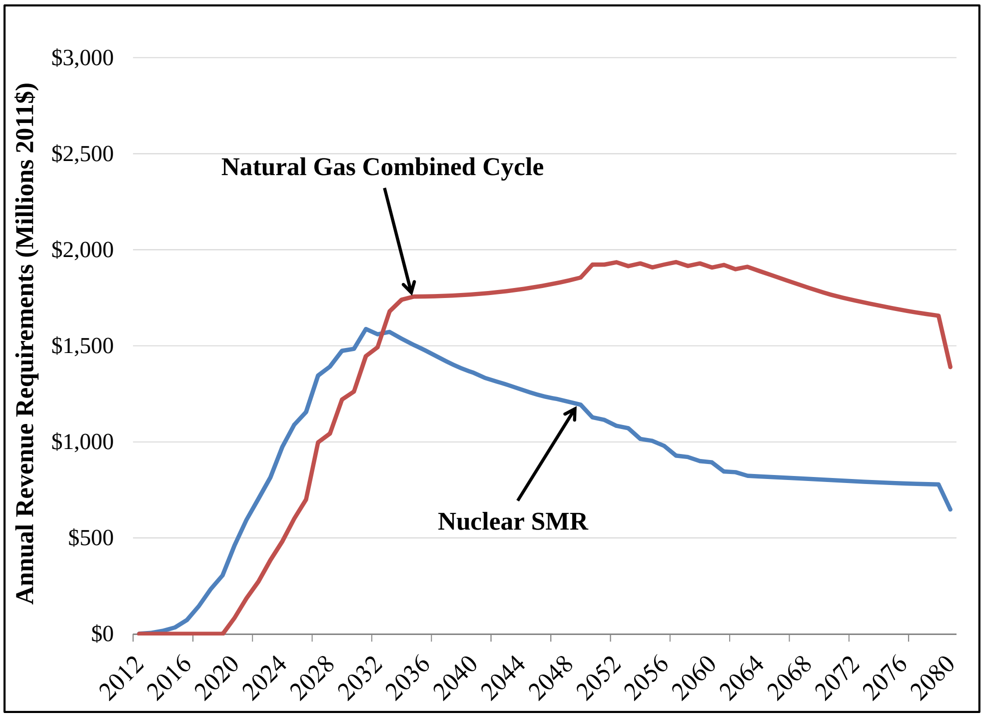


Figure 66: Annual Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment for Scenario G (High Natural Gas Supply, High Growth, No Carbon Pricing), 2012-2080 (2011$ Millions)

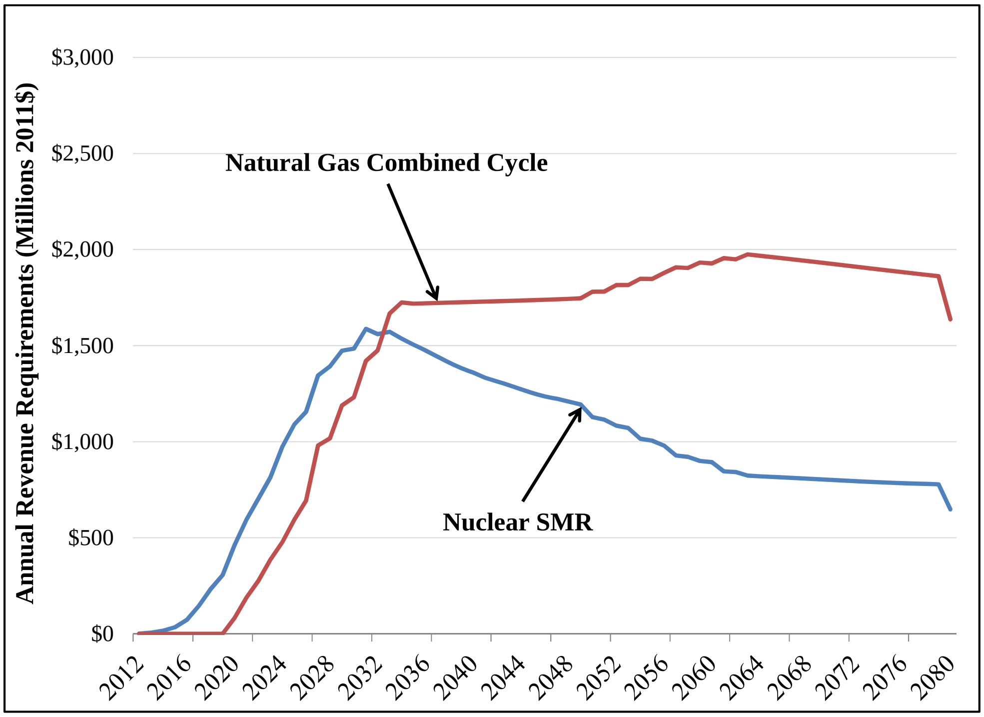


Figure 67: Annual Revenue Requirements for Nuclear SMR and Natural Gas Combined Cycle Deployment for Scenario H (High Natural Gas Supply, High Growth, Carbon Pricing), 2012-2080 (2011$ Millions)

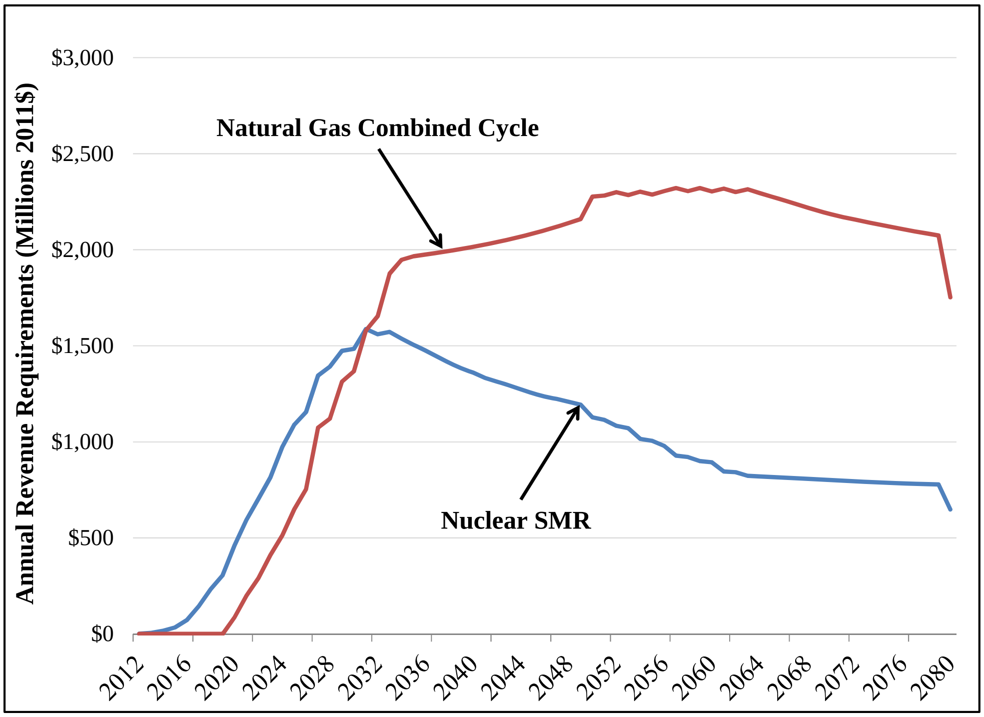
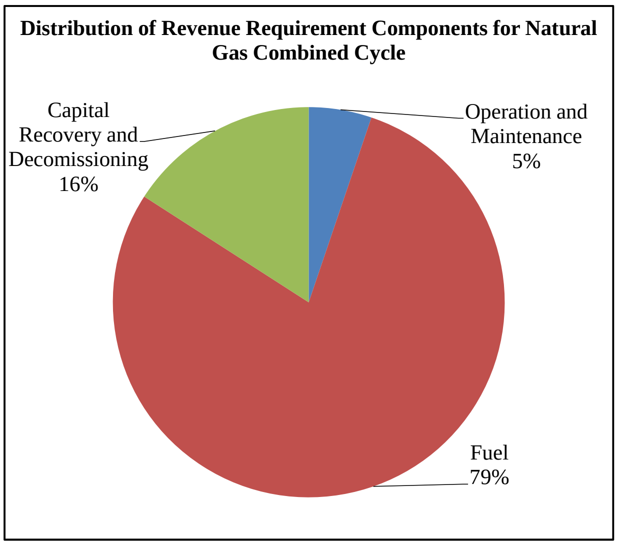


Figure 68 through Figure 72 show the allocation of costs on the major cost components of a natural gas combined cycle deployment for each energy market scenario and the nuclear SMR deployment alternative, which does not change by energy market scenario.

Recovering the capital investment dominates the revenue requirement for a nuclear SMR deployment while fuel costs dominate the natural gas combined cycle deployment. The significant difference in these allocations directly impacts economic development in Iowa. The capital investment requirement of the nuclear SMR deployment has the potential for a greater positive impact within Iowa relative to the fuel cost requirement of the natural gas combined cycle deployment.

Figure 68: Allocation of NPV Revenue Requirements for Natural Gas Combined Cycle Deployment – Scenarios A and B

Scenario A (Low Natural Gas Supply, Low Growth, No Carbon Pricing)



Scenario B (Low Natural Gas Supply, Low Growth, Carbon Pricing)

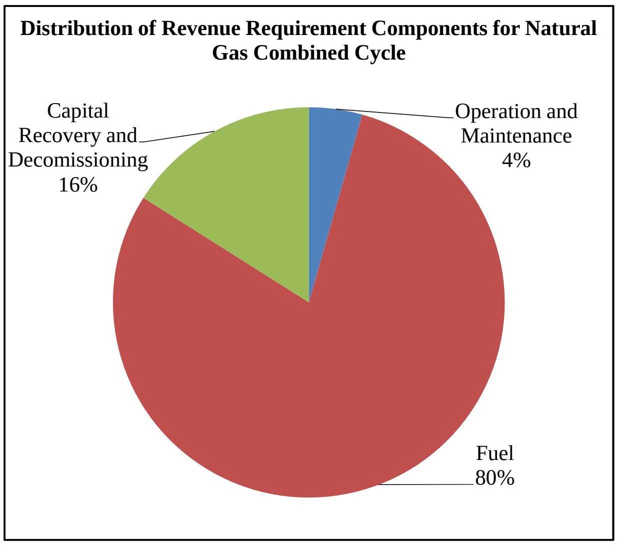
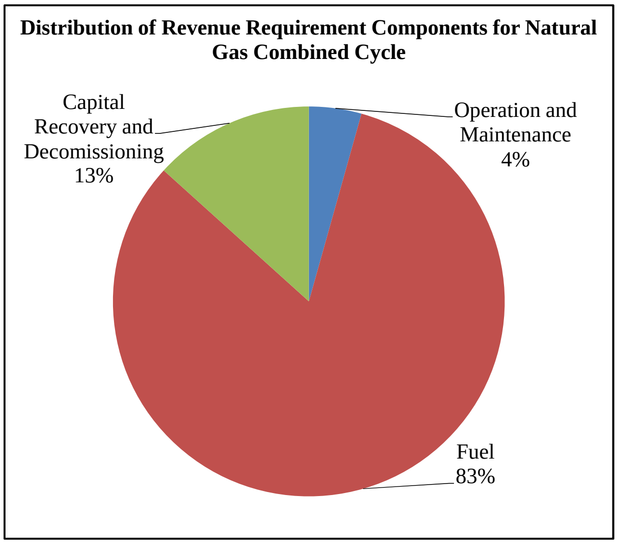


Figure 69: Allocation of NPV Revenue Requirements for Natural Gas Combined Cycle Deployment – Scenarios C and D

Scenario C (Low Natural Gas Supply, High Growth, No Carbon Pricing)



Scenario D (Low Natural Gas Supply, High Growth, Carbon Pricing)

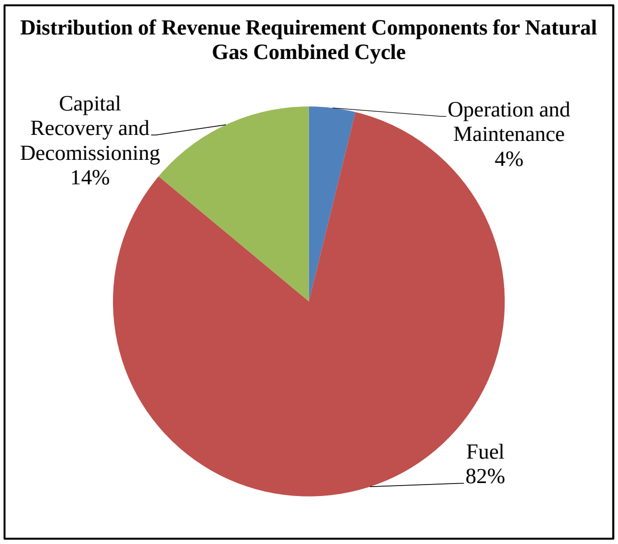
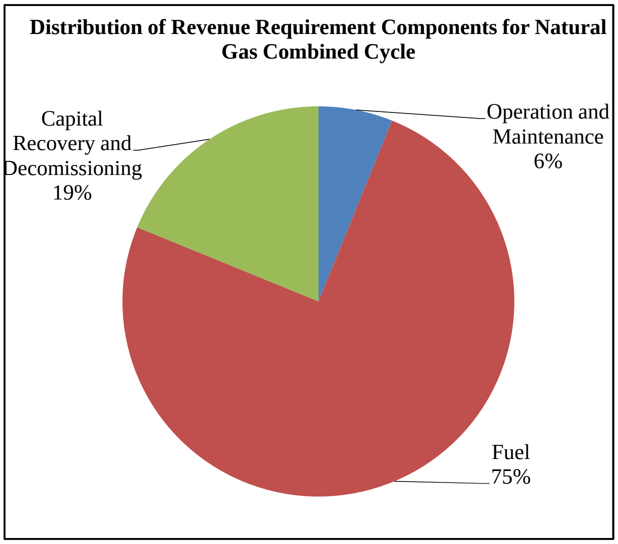


Figure 70: Allocation of NPV Revenue Requirements for Natural Gas Combined Cycle Deployment – Scenarios E and F

Scenario E (High Natural Gas Supply, Low Growth, No Carbon Pricing)



Scenario F (High Natural Gas Supply, Low Growth, Carbon Pricing)

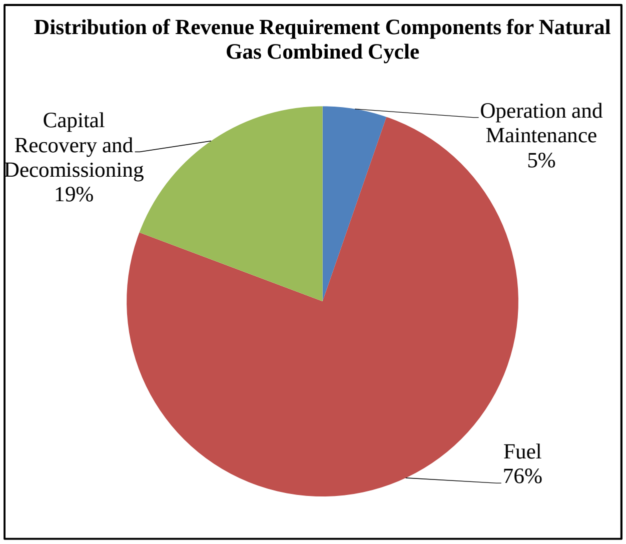


Figure 71: Allocation of NPV Revenue Requirements for Natural Gas Combined Cycle Deployment – Scenarios G and H

Scenario G (High Natural Gas Supply, High Growth, No Carbon Pricing) | **Scenario H** (High Natural Gas Supply, High Growth, Carbon Pricing)

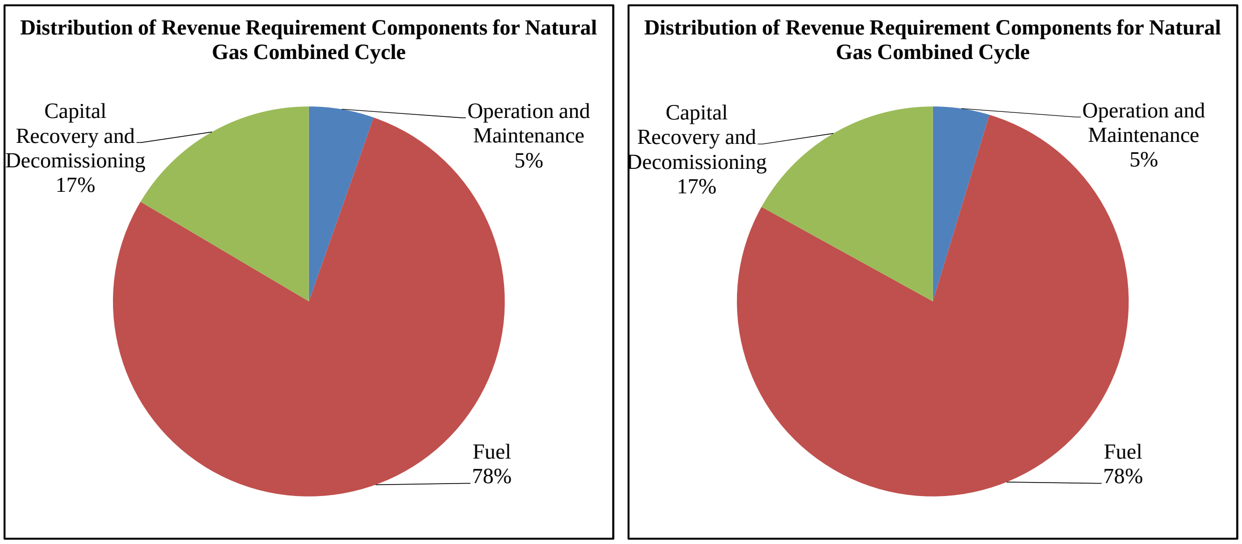


Figure 72: Allocation of NPV Revenue Requirements for Nuclear SMR Deployment, same for all Energy Market Scenarios

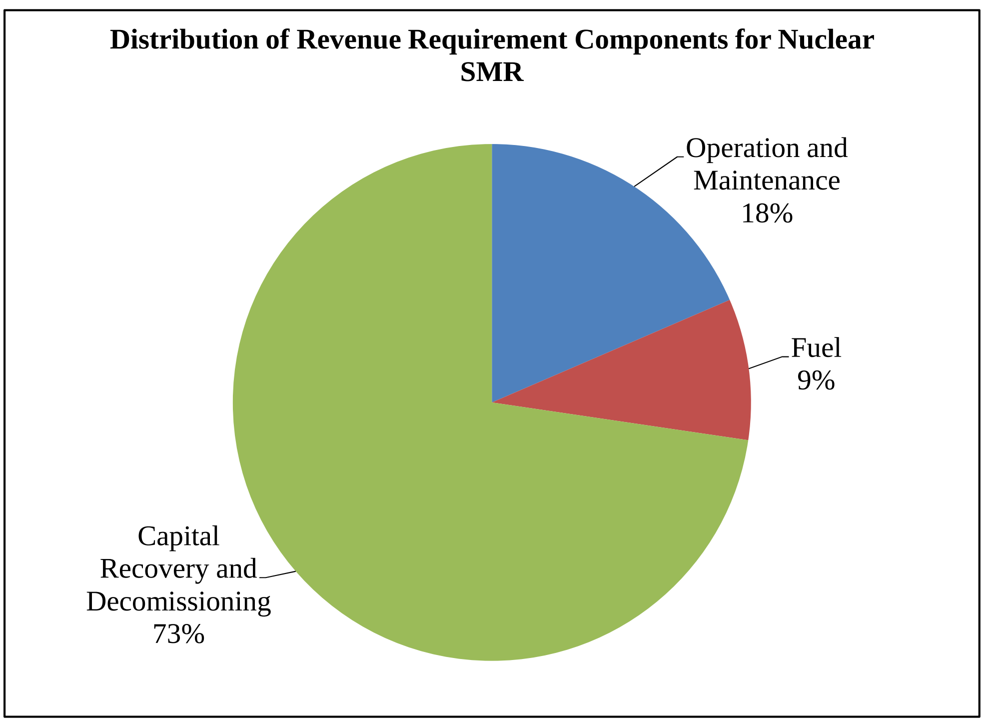


Figure 73 through Figure 83 show the all sector Iowa retail electricity rates for all energy market scenarios as developed by the NEMS-MEC model,[91] and allow the retail electricity rates under a natural gas combined cycle deployment to be compared with those under a nuclear SMR deployment for each potential energy market future. The first two figures show the rates for all scenarios given a natural gas combined cycle deployment (Figure 73) and a nuclear SMR deployment (Figure 74). Figure 75 compares the probability weighted average retail rates across the eight energy market scenarios with a natural gas combined cycle deployment to a nuclear SMR deployment. The remaining figures show comparisons of the electricity rates for each energy market scenario. Across all of the scenarios, the deployment of nuclear SMR results in less variation in future retail electricity rates than if natural gas combined cycle were to be deployed. This is because the reliance on natural gas adds fuel volatility, while deploying nuclear SMR provides greater cost certainty over time since the majority of costs are related to capital recovery and operation and maintenance costs.

The timing of the costs for each deployment alternative has significant impact on the pattern and magnitude of changes to electricity rates for customers in MROW. In general, for any given energy market scenario, the nuclear SMR deployment results in lower long-run electricity rates than the natural gas combined cycle deployment, but near term electricity rates are higher.

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[91] Rates developed by the NEMS-MEC model are indicative rates, but do not contain the level of detail that would be prepared by MidAmerican for purposes of its rate hearings.

Figure 73: All Sector Retail Electricity Rates for Iowa Assuming Natural Gas Combined Cycle Deployment, Eight Energy Market Scenarios, 2012-2080 (2011¢/kWh)

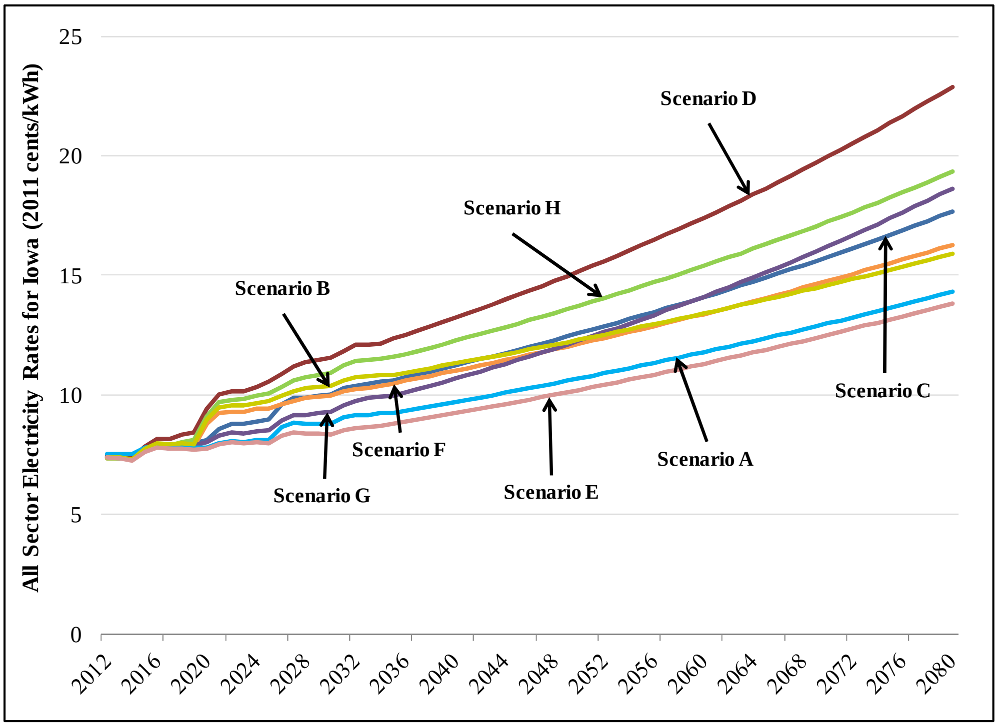


Figure 74: All Sector Retail Electricity Rates for Iowa Assuming Nuclear SMR Deployment, Eight Energy Market Scenarios, 2012-2080 (2011¢/kWh)

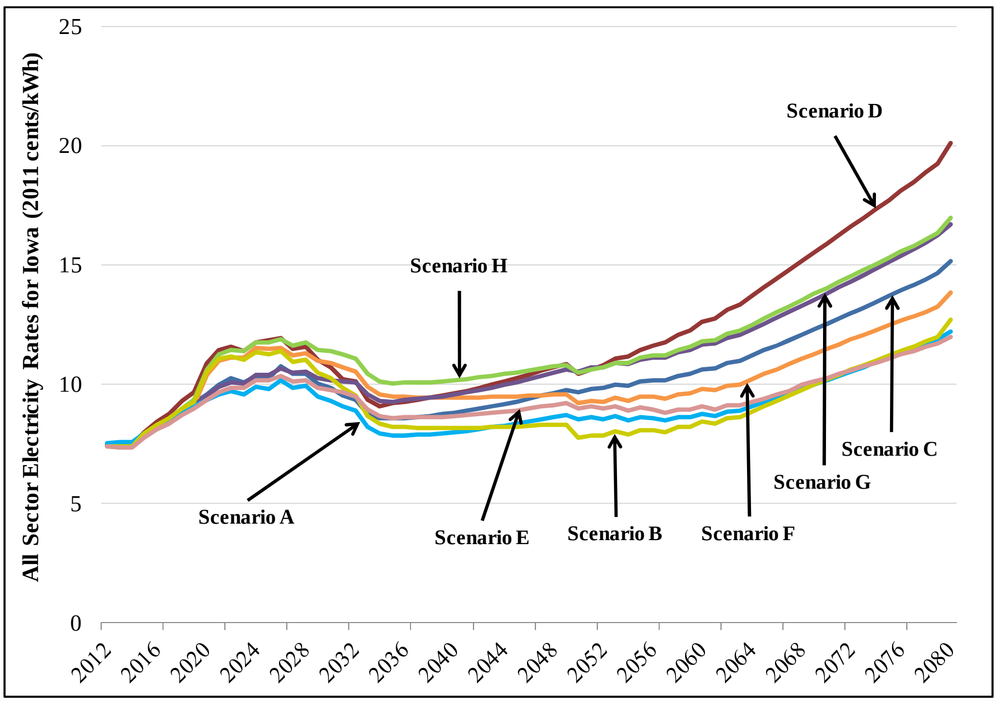


Figure 75: All Sector Retail Electricity Rates for Iowa with Nuclear SMR Deployment and Natural Gas Combined Cycle Deployment, Average across All Eight Energy Market Scenarios, 2012-2080 (2011¢/kWh)

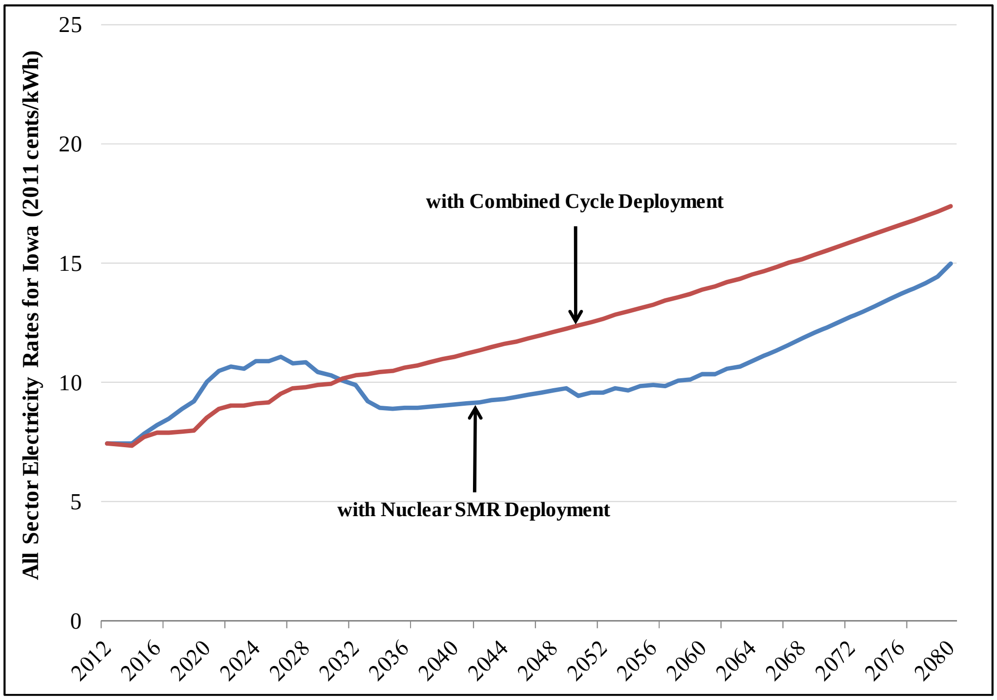


Figure 76: All Sector Retail Electricity Rates for Iowa with Nuclear SMR Deployment and Natural Gas Combined Cycle Deployment, Scenario A (Low Natural Gas Supply, Low Growth, No Carbon Pricing), 2012-2080 (2011¢/kWh)

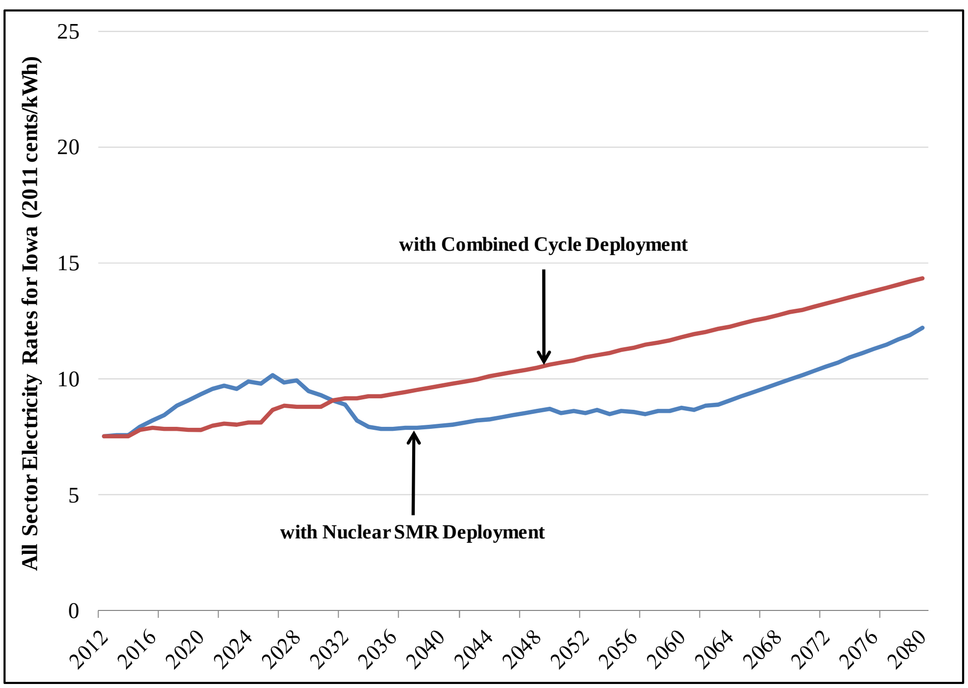


Figure 77: All Sector Retail Electricity Rates for Iowa with Nuclear SMR Deployment and Natural Gas Combined Cycle Deployment, Scenario B (Low Natural Gas Supply, Low Growth, Carbon Pricing), 2012-2080 (2011¢/kWh)

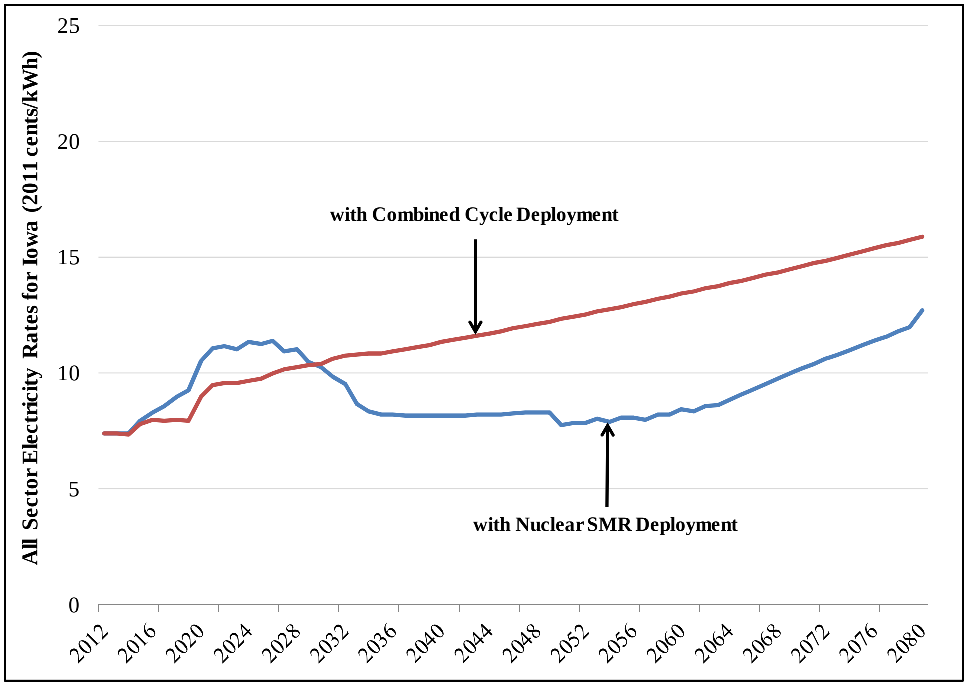


Figure 78: All Sector Retail Electricity Rates for Iowa with Nuclear SMR Deployment and Natural Gas Combined Cycle Deployment, Scenario C (Low Natural Gas Supply, High Growth, No Carbon Pricing), 2012-2080 (2011¢/kWh)

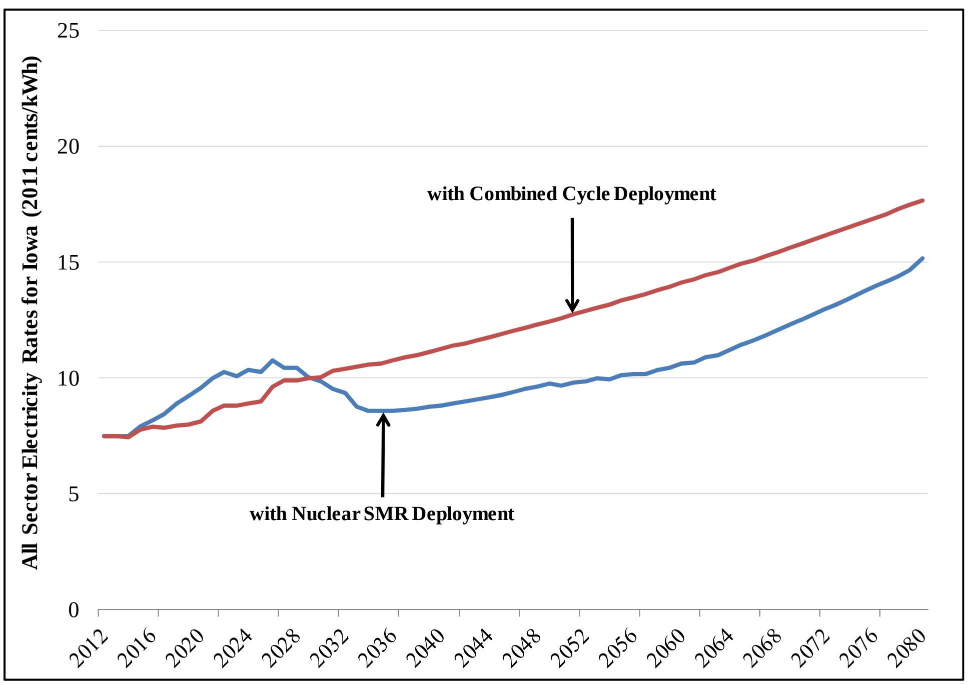


Figure 79: All Sector Retail Electricity Rates for Iowa with Nuclear SMR Deployment and Natural Gas Combined Cycle Deployment, Scenario D (Low Natural Gas Supply, High Growth, Carbon Pricing), 2012-2080 (2011¢/kWh)

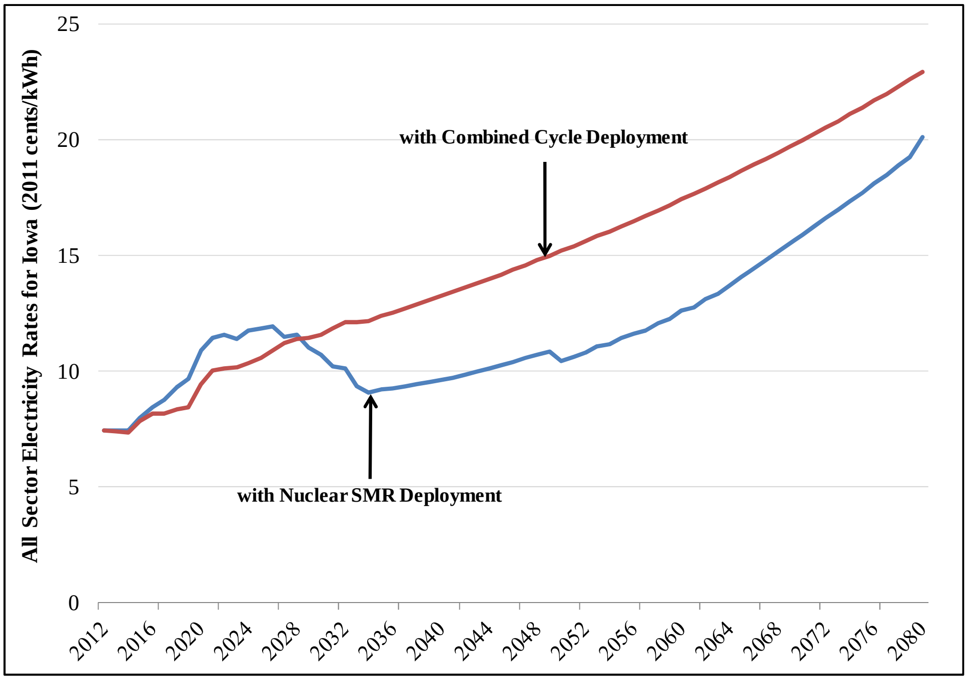


Figure 80: All Sector Retail Electricity Rates for Iowa with Nuclear SMR Deployment and Natural Gas Combined Cycle Deployment, Scenario E (High Natural Gas Supply, Low Growth, No Carbon Pricing), 2012-2080 (2011¢/kWh)

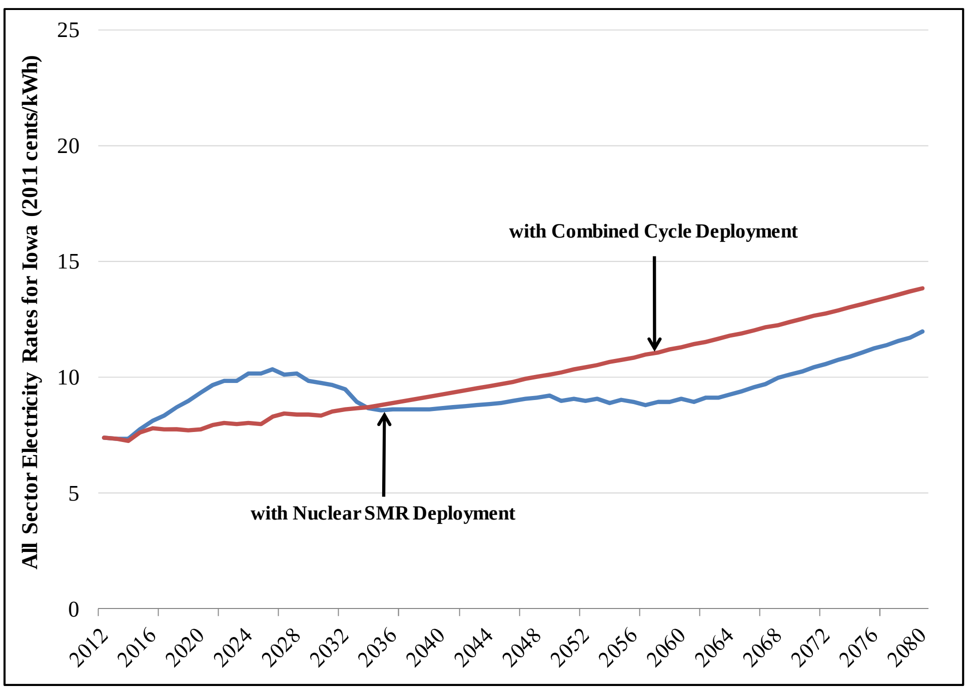


Figure 81: All Sector Retail Electricity Rates for Iowa with Nuclear SMR Deployment and Natural Gas Combined Cycle Deployment, Scenario F (High Natural Gas Supply, Low Growth, Carbon Pricing), 2012-2080 (2011¢/kWh)

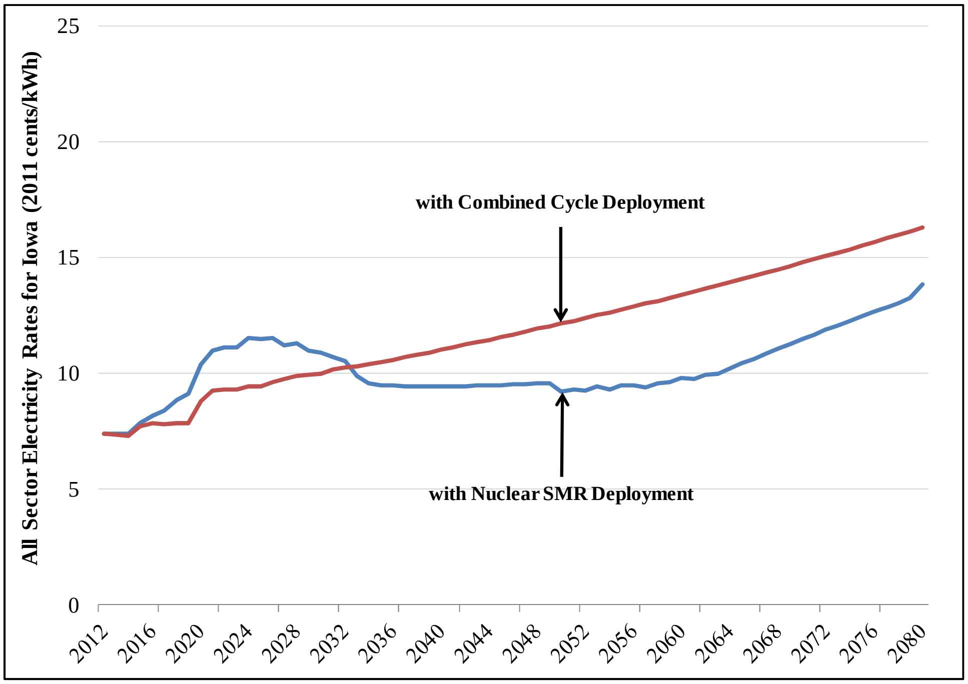


Figure 82: All Sector Retail Electricity Rates for Iowa with Nuclear SMR Deployment and Natural Gas Combined Cycle Deployment, Scenario G (High Natural Gas Supply, High Growth, No Carbon Pricing), 2012-2080 (2011¢/kWh)

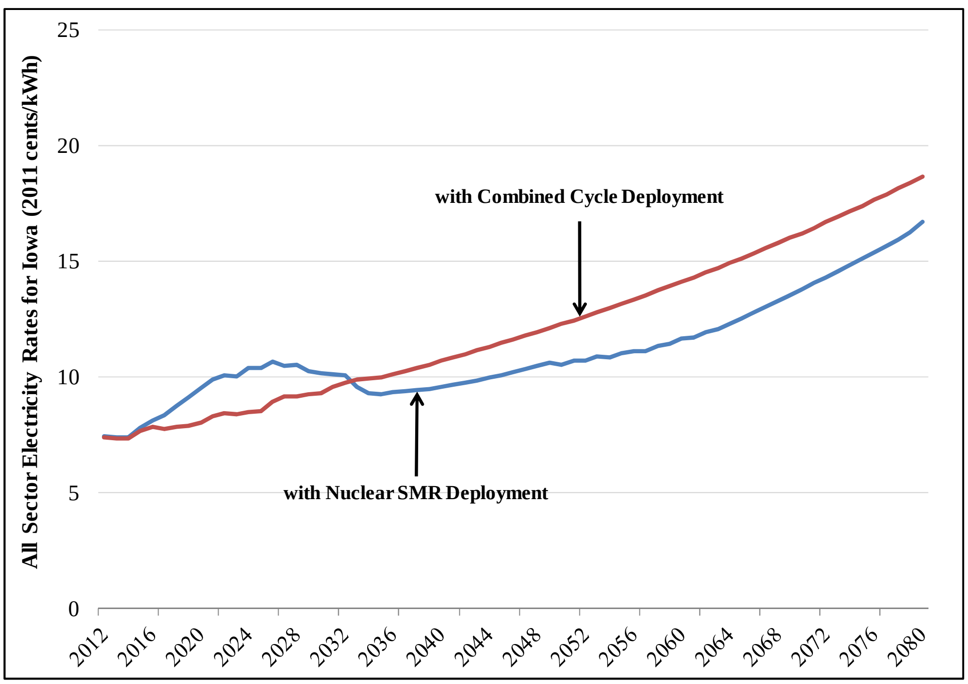
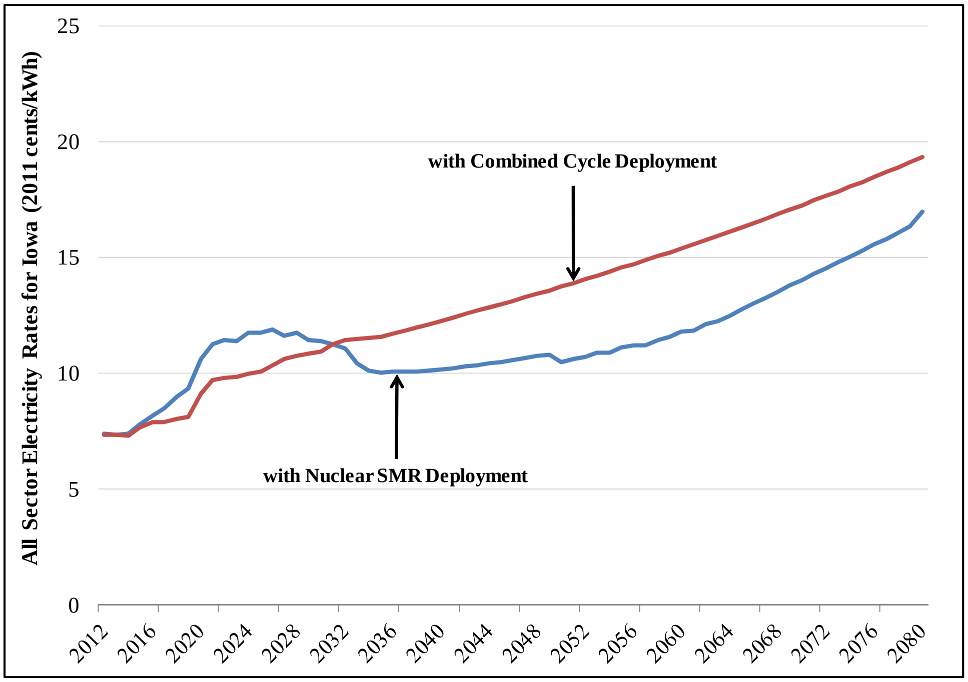


Figure 83: All Sector Retail Electricity Rates for Iowa with Nuclear SMR Deployment and Natural Gas Combined Cycle Deployment, Scenario H (High Natural Gas Supply, High Growth, Carbon Pricing), 2012-2080 (2011¢/kWh)

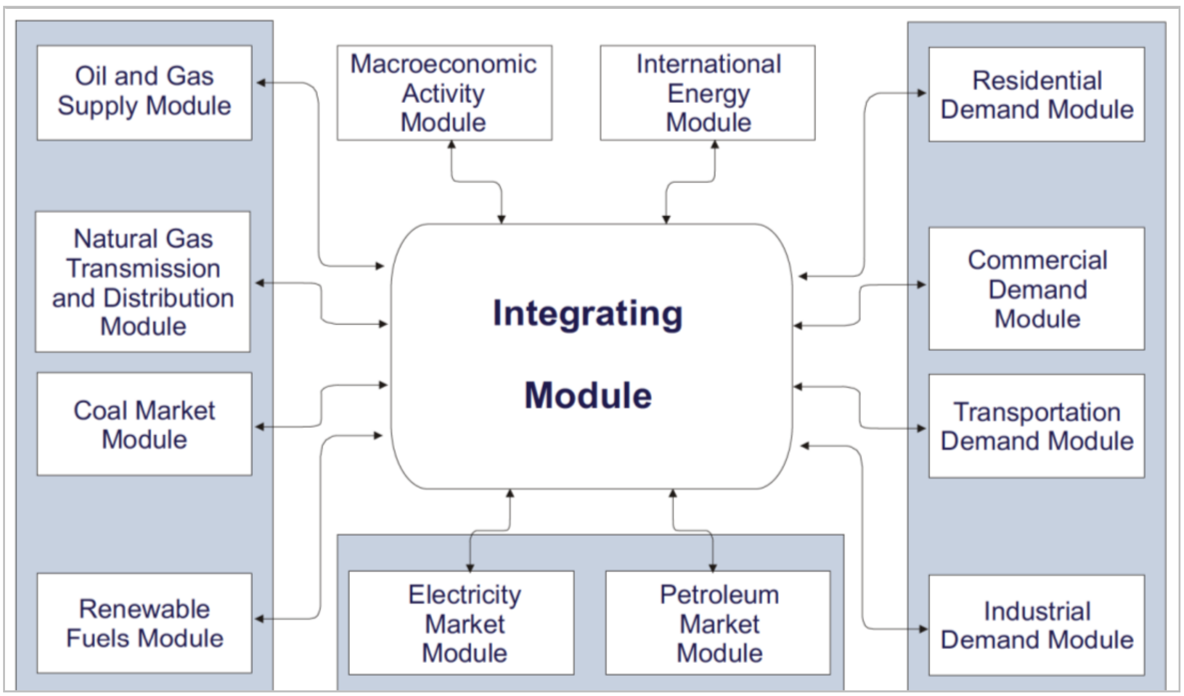


APPENDIX B – Model Descriptions

NEMS-MEC Model

NEMS-MEC is an integrated regional model of the U.S. energy system. It is modular in design, with each energy sector represented in the manner most natural to its character and an integration function passing energy prices and quantities among them. The individual modules of NEMS-MEC employ a variety of modeling techniques, including simulation, optimization, and econometrics in their formulation of the different energy sectors. For example, the electricity and refinery sectors use optimization, while the demand models employ a mix of engineering and economic based simulation methods. The modular design allows individual models to be run alone with exogenous assumptions as well as the whole model running in a fully integrated mode.

Figure 84: NEMS-MEC Overview



Source: U.S. EIA, Office of Energy Analysis.

The NEMS model was built and is maintained by the EIA and is used by them to produce annual energy projections and to respond to Congressional and Administration requests for special policy studies. It is also widely used by offices within the DOE and by others outside the government. As such it is extensively reviewed, and significant resources are expended on its upkeep and continued evolution. NEMS-MEC is the version of the model that has been adapted for use in this analysis.

Representation of Electricity Markets

The electricity sector is one of the most detailed and data intensive within NEMS. The EMM consists of four models: the Electricity Capacity Planning Model (“ECP”), the Electricity Fuels and Dispatch Model (“EFD”), the Electricity Finance and Pricing Model (“EFP”), and the Load and Demand Side Management Module (“LDSM”).

The EMM projects new generation capacity, environmental controls to meet required emission caps and resulting allowance prices, dispatch of generation, and electricity prices. The model starts with a database describing key economic and technical performance characteristics (*e.g.*, heat rates, capacity, pollution control technologies, and emission rates, etc.) of all existing power plants. In addition, the EMM is initialized with selected financial data that allows the estimation of cost of service based electricity prices in those regions where this is relevant. Given these initial conditions, the ECP assesses the need for new capacity in the context of the forecast economic and regulatory environment (emission constraints). The EFD estimates the use of alternative fuels (unit dispatch) given the cost of the fuels, the relative efficiencies of the generating technologies, and the costs of meeting various environmental constraints (*i.e.*, emission allowances). The EFP estimates the retail price of electricity under competitive market (marginal costs) and cost-of-service pricing regimes. The LDSM constructs load duration curves used by the ECP and EFD from the end use demands levels estimated in other NEMS modules.

The EMM deploys new capacity and dispatches available capacity to meet demand in each of 22 regions (formed around NERC regional and sub-regional boundaries – see figure below). The environmental constraints of SO_2, NO_X, and mercury emissions are met through the least-cost mix of equipment retrofits, fuel mix (including switching among coal types), and dispatch.

Dispatch is performed based on marginal costs, with the exception of must-run units, and includes inter-regional trading opportunities. Electricity prices are projected by component (*i.e.*, generation, transmission, and distribution) based on the regulatory framework in place in each region. For some regions (*e.g.*, New England) generation prices are based on competitive marginal costs. In other regions (*e.g.*, most of the sub-regions of SERC) prices are based on regulated cost-of-service or average costs. Transmission and distribution is assumed to be regulated in all regions, and it is priced based on continuing investments in transmission and distribution facilities, their inclusion in rate base, and associated annual operation and maintenance expenses.

OnLocation played a pivotal role in the design and implementation of the original EMM. In their continuing role as support contractor to EIA, they continue to make major contributions to extending EMM’s ability to address the evolving environmental regulations and the power industry’s response to evolving issues surrounding FERC and state initiatives focusing on competitive markets and commitments to renewable technologies. They performed a significant part of the work required in increasing the number of EMM regions from 13 to 22 that included model modifications as well as data analysis. They also introduced a methodology to explicitly expand transmission constraints between regions if lower cost capacity could be constructed at a distance rather than inside the native load region.

Figure 85: NEMS Electricity Market Module Regions

Fuel Markets

NEMS-MEC includes an extensive modeling framework for addressing all the significant fuel markets. Due to the full scope of the model, NEMS-MEC addresses the fuels markets in the context of all energy consuming sectors at the regional level: residential, commercial, industrial, and transportation. Further, due to their key role in the conversion and delivery of energy products, NEMS-MEC includes a detailed modeling framework for addressing the electricity and petroleum conversion markets.

The fossil fuel supply modules are built based on fundamental principles of resources and extraction costs. The natural gas and oil supply module projects domestic supply for several lower 48 onshore regions, offshore regions, and Alaska. Unconventional gas recovery from tight sand formations, coalbeds, and gas shales are represented. Based on profitability, exploratory and development drilling are undertaken within each region and fuel type. Reserve additions and production capacities are forecasted for each region.

Coal supply is represented by mining region and coal type. These supply curves are connected to demand regions by transportation costs that vary over time. Two tiers of delivery costs are represented. The first is the cost of existing delivery quantities, while the second is an estimate of expanded shipments to those power plants not currently using that type of coal.

The integrated fuel markets framework of NEMS-MEC allows it to address the interrelationships in the pricing and demand for energy products in each sector. For example, the demand for natural gas is driven not only by the electricity markets but also by the use of natural gas in the residential, commercial, and industrial sectors. This inter-sector competition for fuel commodities is particularly important when addressing such scenarios as constrained petroleum supplies (and associated higher prices) or constraints on GHGs when applied across the entire energy economy.

Due to the complexities and the interrelationships in the markets for fuel commodities and environmental regulations and their associated constraints on fuel use, each of the fuel markets are tied closely into the EMM. This relatively tight binding of the various models allows the electricity market to look forward and anticipate the fuel price implications of these regulations on the relative economic performance of competing technologies.

NEMS-MEC includes a relatively rich technology and supply framework for renewable fuels. This framework includes: regional wind supply curves, regional biomass supply curves, explicit treatment of ethanol (corn and cellulosic) fuels and other biofuels, and regional solar and geothermal potential. The renewable technology slate is used to represent RPSs for power generation (state or federal) and renewable fuel standards for liquid fuels as well as provide an additional fuel commodity to respond to various environmental constraints. Competition for biomass for power and biofuels is explicitly treated and can be important in responding to renewable standards as well as GHG mitigation policies.

Another dimension of the fuel markets is their growing internationalization and its impact on the domestic markets in the U.S. To address this issue, NEMS-MEC includes explicit modeling of imports and exports in the natural gas (pipeline and liquids), coal, and electricity markets. NEMS-MEC explicitly accounts for the potential new Canadian and Alaskan natural gas pipelines and has a feature to allow for siting LNG terminals and the importation of LNG.

Energy Demand

Energy demand projections encompass all sectors and fuels and interact with the fuel supplies in determining energy prices. In particular, electricity demand levels impact the need for the generation capacity, and higher levels of demand put more pressure on emission allowance and fuel prices. Natural gas demands by end-use consumers can also impact natural gas prices and the attractiveness of gas as a generation fuel.

The demand models of NEMS-MEC are characterized by end-use sector: residential, commercial, industry, and transportation. Residential and commercial buildings are represented at the end-use level, for example space heating, cooling, lighting, and so forth. Within the major end-uses, technologies and fuels compete to satisfy demand. The model will adopt more energy efficient technologies as prices increase. As a result, demand will gradually adjust through the turnover of equipment stock. In addition, the building models contain short-term price elasticities that impact some end-use demands directly.

The industrial sector is represented by industry type and by generic service demands. For the most part, individual technologies are not represented, but rather efficiency changes over time based on autonomous improvement factors developed for each industry are applied to a representation of existing technologies. Fuel choice for boilers is based on relative fuel prices. The buildings and industrial sectors have explicit representation of distributed generation technologies that provide an alternative to grid-purchased electricity as well as opportunities for meeting RPS requirements depending on policy design.

REMI PI+ Model

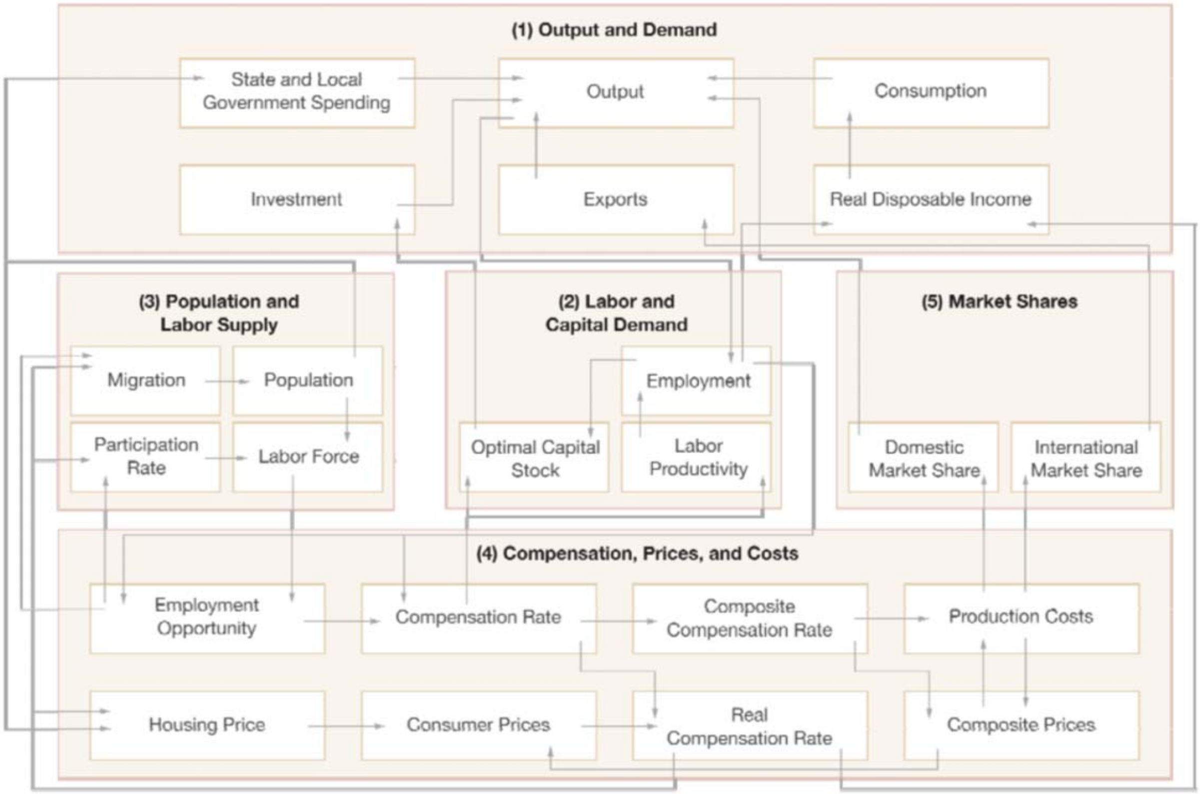
The REMI PI+ model is a structural dynamic forecasting model based upon the assumptions that households maximize utility and producers maximize profits. In the model, businesses produce goods to sell to consumers, investors, governments, and other firms both within and outside of their own regions. Such goods are produced using labor, capital, fuel, and intermediate inputs.

Each version of the REMI PI+ model is custom-built for the regions of interest, which can range from counties to entire countries. The REMI PI+ model incorporates detailed and up-to-date macroeconomic data from the U.S. Bureau of Economic Analysis, the U.S. Bureau of Labor Statistics, the U.S. Census Bureau, and other public sources. The REMI PI+ model is widely used by federal, state, and local agencies, as well as analysts in the private sector and academia, to estimate the effects of regulations, investments, closures, and other scenarios.

Wages, prices, and productivity determine the cost of doing business for every industry in the model. Wages are determined by the supply and demand for labor, while the productivity of labor and intermediate inputs depends on the availability of access to them. The demand for labor, capital, and fuel per unit of output depends on their relative costs, since an increase in the price of any one of these inputs leads to substitution away from that input to other inputs. The supply of labor in the model depends on the number of people in the population and the proportion of those people who participate in the labor force.

Figure 86 shows the five blocks in the REMI PI+ model and their linkages. The Output and Demand block balances supply and demand for all major sectors of the economy, including both domestic and international sources of supply and demand. The Labor and Capital Demand block models employment and capital stock based on output, wage rates, and capital costs. The Population and Labor Supply block models labor participation rate and population based on wage rates in the various regions and the size of the various sectors. The Compensation, Prices, and Costs block models each sector's production cost, including labor cost based on wage rates. Finally, the Market Shares block uses production cost to model each sector's domestic market share and international market share, which are passed back up to the Output and Demand block.

Figure 86: Key Blocks and Linkages in the REMI Model



Source: REMI (2012)

APPENDIX C – Comparisons to AEO 2012 (June Release)

Since NERA and OnLocation completed the modeling in this analysis, the EIA has produced AEO 2012, which includes updates to assumptions used in the NEMS model. In particular, there have been updates to natural gas supply, which result in new equilibrium natural gas demand and natural gas prices. The AEO 2012 Reference Case still does not include a GHG reduction policy or a price on carbon emissions.

Figure 87 shows a comparison in the economy-wide natural gas demand and Henry Hub natural gas prices between the Reference cases in AEO 2011 and AEO 2012. AEO 2012 has similar natural gas demand as in AEO 2011, but the Henry Hub prices are lower through 2033. NERA reviewed the available documentation of AEO 2011 and AEO 2012 and spoke with EIA's primary natural gas contact. EIA made a downward adjustment of 320 Tcf in the recoverable shale resource estimates from AEO 2011 to AEO 2012. The total U.S. natural gas technically recoverable resource was also down by 340 Tcf. This, however, did not translate into higher price (except in 2034 and 2035) or lower demand. NERA's discussions with EIA were focused on trying to better understand this seeming inconsistency. The EIA contact told NERA that EIA also updated its decline rate information (particularly for the Marcellus shale basin) and lowered its natural gas production costs in the near term somewhat. The lower near term production costs can be clearly seen in the dip in prices in 2012, prior to maintaining a similar growth pattern after 2012. The EIA contact told NERA that the reduction in the natural gas resource, while large, still has little impact on the AEO model horizon (through 2035), because the lower natural gas resource figure still includes plenty of natural gas to meet demand through 2035.

Given the combination of the updates between the AEO 2011 and AEO 2012 Reference Cases, it is clear that if the AEO 2012 Reference Case had been available to NERA for this analysis then the scenarios based on the Reference case (scenarios E, F, G and H) would have had lower natural gas prices from 2020 through 2033 (prices prior to 2020 are irrelevant to the study). Post-2033, the prices for scenarios based on the reference case would have likely been higher based on the price crossover as well as the lower overall natural gas resource.

Figure 87: Comparison of AEO 2012 and AEO 2011 Reference Case Natural Gas Demand and Prices

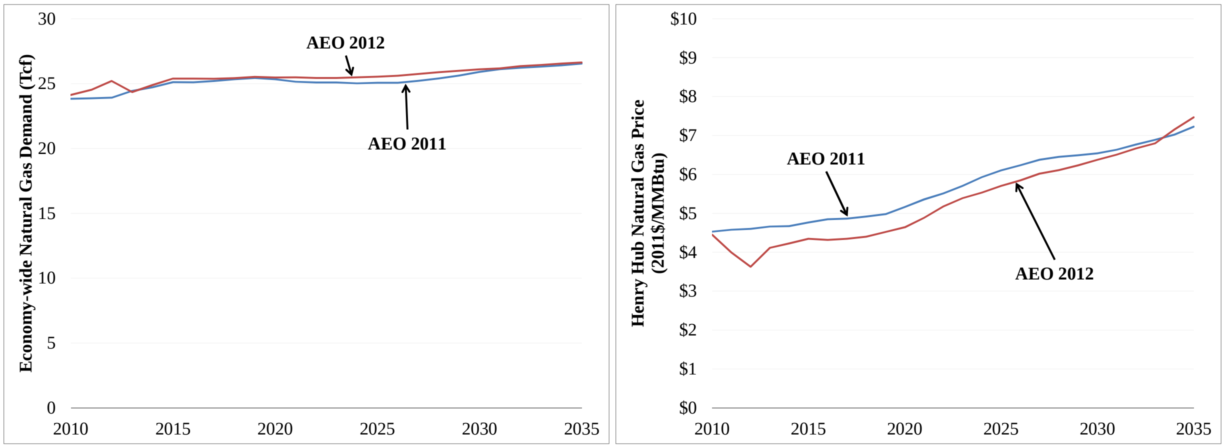
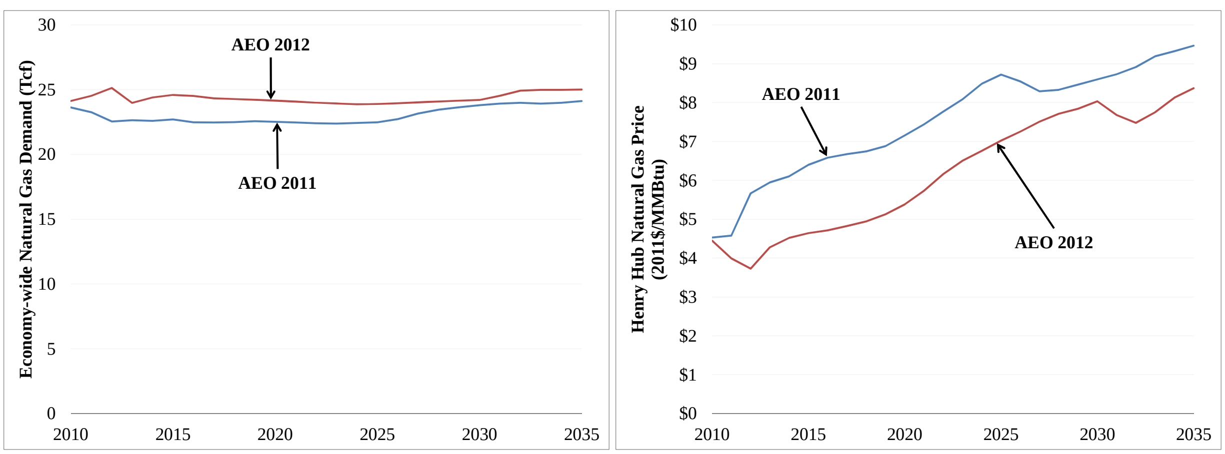


Figure 88 shows a comparison in the economy-wide natural gas demand and Henry Hub natural gas prices between the Low EUR Cases in AEO 2011 and AEO 2012. The AEO 2012 has lower Henry Hub prices and higher natural gas demand (likely as a result of the lower prices). EIA did not change its definition of the Low EUR Case (still with an EUR that is 50% lower per well than in the Reference case), so this cannot explain the resulting prices being lower by $1.50/MMBtu through about 2025. In 2035, the last year of the projection, the price difference is about $1.00/MMBtu. Thus, while it is clear that if the AEO 2012 Low EUR Case had been available to NERA for this analysis then the scenarios based on the Low EUR Case (scenarios A, B, C and D) would have had lower natural gas prices from 2020 through 2035. However, it is unclear how and when the lower natural gas resource would have a more significant impact.

Figure 88: Comparison of AEO 2012 and AEO 2011 Low Shale EUR Natural Gas Demand and Prices



APPENDIX D – Qualifications

Founded in 1961, NERA is the oldest and largest firm of consulting economists specializing in the application of microeconomic principles to regulatory issues, industrial organization, policy evaluation, and business strategy. NERA's global team of 500 professionals operates in 16 offices across North and South America, Europe, and the Asia-Pacific region.

Institutional development and the liberalization of regulated energy sectors has been the central focus for NERA in the past 50 years, and one in which we are leaders on an international scale. NERA's Energy Practice combines regulatory, restructuring and privatization experience—particularly related to the detailed elements of energy utility financing, development and tariff control. In its work around the world, NERA consistently promotes the development of energy markets and attempts to structure efficient and workable regulatory mechanisms.

The NERA team that worked on this engagement brings together expertise across all aspects of the energy sector. Below are a subset of recent projects and experiences by the authors.

- Developed long-term fuel forecast scenarios (natural gas, coal and oil through 2050) used by a large vertically-integrated utility in all of their long-term planning and strategic decision making analyses, including those presented to respective state utility commissions. (Scott Bloomberg)

- Assisted AmerenUE with its integrated resource plan (IRP) for the state of Missouri by providing a consistent set of integrated inputs across a range of policy and commodity price scenarios. This analysis also included a probabilistic analysis and formal risk assessment. (Scott Bloomberg)

- Expert witness on costs and risks, Public Utilities Commission of the State of Colorado, Docket No. 10M-245E, in the matter of the Commission consideration of Public Service Company of Colorado Plan in compliance with House Bill 10-1365, "Clean Air – Clean Jobs Act." (Anne Smith)

- Expert witness on cost and economic impacts, State of New Mexico Environment Improvement Board, EIB 10-04(R), in the matter of Proposed Regulation 20.2.350 NMAC – "Greenhouse Gas Cap and Trade Provisions." (Anne Smith)

- Expert witness on climate policy and natural gas and carbon price scenarios before the Mississippi Public Utilities Commission Docket No. 2009-UA-0014, on behalf of Mississippi Power. (W. David Montgomery)

- Expert witness on natural gas prices and contracts on behalf of Peabody Energy Corporation. Before the Colorado Public Service Commission, Hearing on Implementation of the Clean Air Clean Jobs Act, December 2010. (W. David Montgomery)

- Retained to provide detailed study of issues related to nuclear power plant costs and electricity industry economics, electricity markets, and related issues for a country considering its first nuclear power plant. (Edward Kee)

- For U.S. Department of Energy, provided analysis of regulatory and market risks of proposed new U.S. nuclear power plants in support of the U.S. DOE nuclear loan guarantee program. For the regulated utility project applicants, the assessment included detailed assessment of regulatory rate recovery risk in multiple U.S. states. (Edward Kee)

- Studied the options for providing natural gas supplies to a proposed combined cycle plant. This evaluation considered contracting for natural gas storage service, firm versus interruptible transportation service on pipelines, and related balancing rules and penalties on relevant pipelines. (Robert Baron)

- Economic impact analysis on state of New Mexico resulting from implementation of state's greenhouse gas cap-and-trade program using the REMI model and a detailed cash flows analysis to track the flow of funds within New Mexico. (Andrew Foss)

- Using the NEMS model, explored the implications of various environmental legislative proposals, including the Bush Administration's Clear Skies Act, Senator Bingaman's Climate and Economy Insurance Act, Senator Carper's Clean Air Planning Act, and Senators McCain-Lieberman Climate Stewardship Act. (OnLocation)

- Using the NEMS model, analyzed the effects of renewable energy incentive programs such as an extension of the current production tax credits and implementation of a nation-wide renewable portfolio standard. (OnLocation)

The following provides some additional qualifications for the authors:

- Scott Bloomberg: Mr. Bloomberg, Vice President, is an expert in electric sector modeling, including the modeling of complex policies and regulations. He also has extensive experience in long-term planning within the electric sector, having assisted numerous utilities with long-term forecasts for planning purposes and integrated resource plans that account for the key uncertainties faced by utilities. Mr. Bloomberg has a M.B.A. from the University of Chicago, Booth School of Business.

- Anne E. Smith: Dr. Smith, Senior Vice President and co-head of NERA's Global Environment Group, has made major analysis contributions on many important environmental policy issues, including global climate change and air quality standards (*e.g.*, SO_2, NO_X, VOC, $PM_{2.5}$, mercury, visibility). She is an expert in environmental policy assessment and corporate compliance strategy planning, specializing in market impact analysis, risk management, and integrated policy assessment. She has also testified before the U.S. Congress on environmental issues in the electric sector. Dr.

Smith has a Ph.D. in economics from Stanford University, where she also completed a Ph.D. minor in Stanford's Engineering Department.

- W. David Montgomery: Dr. Montgomery, Senior Vice President, has worked on a range of natural gas and environmental issues over his more than 20 year consulting career. His scholarly work is frequently published in peer-reviewed journals, and Congressional committees have requested his testimony on climate change, issues affecting oil and gas markets, and other energy market, and environmental issues. In addition, prior to entering consulting he led the energy modeling and forecasting activities at the U.S. Department of Energy's Energy Information Administration (EIA). Dr. Montgomery has a Ph.D. from Harvard University in economics.

- Sebastian Mankowski: Mr. Mankowski, Consultant, specializes in assessing national and regional effects of evolving energy markets and proposed environmental regulations. He has led and been a part of projects for several clients involving environmental regulations and policies, domestic and international emissions and energy commodity markets, asset management strategies, and evaluation of investment options. Mr. Mankowski has a M.S. in mechanical engineering from Columbia University.

- Edward Kee: Mr. Kee, Vice President, is an expert on nuclear power. He has recently advised various parties involved in developing new nuclear power plants on topics including board-level due diligence reviews, financing and loan guarantees, nuclear fuel cycle, national nuclear infrastructure development, and nuclear project procurement. Mr. Kee has a M.B.A. from Harvard University.

- Robert Baron: Mr. Baron, NERA Outside Consultant, has worked extensively in all parts of the natural gas industry and will provide his expertise on the need for and cost of natural gas storage and balancing. He brings insights gleaned over 40 years of experience in the energy industry. Mr. Baron has a M.B.A. from the Sloan School of Management at M.I.T.

- Andrew Foss: Mr. Foss, Consultant, has participated in several projects evaluating the potential economic impacts of policies and investments in more than 20 individual states, including extensive experience in modeling economic impacts using the REMI Policy Insight model. Mr. Foss has a Master's in Public Policy, Environmental and Natural Resources from Harvard University, Kennedy School of Government.

- Frances Wood: Ms. Wood, Director at OnLocation, has over 28 years of consulting experience with government and private clients. She has managed the integrated modeling for R&D benefits analysis using NEMS for the DOE Office of Energy Efficiency and Renewable Energy. Ms. Wood also analyzes restructured electricity markets, prices, and environmental policy analysis for an independent power producer. Ms. Wood has a M.S. in Engineering Economic Systems from Stanford University.

- Lessly Goudarzi: Mr. Goudarzi, Managing Director at OnLocation, has over 35 years of experience in management consulting including a wide variety of project specific, industry wide, integrated regional, national, and international energy and environmental policy analyses. Mr. Goudarzi has a M.B.A. from Virginia Tech.

Exhibit RJS-4____

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