

**EMF Report 31  
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# **NORTH AMERICAN NATURAL GAS MARKETS IN TRANSITION**

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**Energy Modeling Forum  
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Stanford, CA 94305-4121**



## Preface

The Energy Modeling Forum (EMF) was established in 1976 at Stanford University to provide a structural framework within which energy experts, analysts, and policymakers could meet to improve their understanding of critical energy problems. The thirty-first EMF study, “North American Natural Gas Markets in Transition,” was conducted by a working group comprised of leading international energy analysts and decisionmakers from government, private companies, universities, and research and consulting organizations. The EMF 31 working group met several times and held many extensive discussions over the 2013-2015 period to identify key issues and analyze the detailed results.

This report summarizes the working group’s discussions based upon the modeling results on alternative views for the booming North American natural gas supplies and their role in expanding natural gas exports and controlling emissions growth within the U.S. power sector. The working group is planning an additional volume of individually contributed papers on many models in the study. Inquiries about the study should be directed to the Energy Modeling Forum, Huang Engineering Center, Stanford University, 475 Via Ortega, Stanford, CA 94305-4121, USA (telephone: (650) 723-0645; Fax: (650) 725-5362). Our web site address is: <http://emf.stanford.edu/>.

We would like to acknowledge the different modeling teams that participated in the study. Their willingness to simulate the different cases and to discuss their results in detail contributed significantly to an excellent study.

This volume reports the findings of the EMF working group. It does not necessarily represent the views of Stanford University, members of the Senior Advisory Panel, any reviewers, or any organizations participating in the study or providing financial support.

## EMF Sponsorship

Financial support from a wide range of affiliated and sponsoring organizations allows the Forum to conduct broad-based and non-partisan studies. During the period covering the study, the Forum gratefully acknowledges the support for its various studies from the following organizations:

America's Natural Gas Alliance	MITRE
American Petroleum Institute	National Energy Board
Aramco Services	Sandia National Laboratory
BP America	Sasol North America
Central Research Institute of Electric Power Industry, Japan	Schlumberger
Chevron	Shell Exploration & Production
Electric Power Research Institute	Southern Company
Électricité de France	TransCanada
Environment Canada	U.S. Department of Energy
Exxon Mobil	U.S. Environmental Protection Agency

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Dean Foreman	Sasol North America
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Ken Hoffman	MITRE Corporation
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## EXECUTIVE SUMMARY

U.S. exports of natural gas are likely to grow over the next five years, a shift unforeseen a decade ago. But this growth may be slow unless U.S. exporters find ways to compete effectively with sources from other regions. This report summarizes the results from a recent study organized by Stanford University's Energy Modeling Forum. The study was conducted by a working group of 50 experts and advisors from a range of diverse universities, research institutes, corporations and government agencies. The study based its assessment on projections made by 16 leading modeling teams in an effort to provide a range of views for energy planning and policymaking.

The United States enjoys a competitive advantage by having lower-priced resources. However, exports to European and Asian markets require large investments in building infrastructure to transport and distribute liquefied natural gas. These expenditures raise the delivered costs of U.S. exports, making them less attractive than many other world supplies. Even with demand growth for natural gas in Japan, China and other Asian countries, exports from the United States will grow only if they can remain competitive with the costs from other regions.

Natural gas exports must also compete with other fuels in these foreign markets. Coal, nuclear and renewables may be more competitively priced than natural gas in many Asian and European countries depending upon market conditions for these fuels.

Domestic conditions like a stronger U.S. demand recovery may also raise domestic prices and make U.S. exports more expensive. One important development will be the country's plans for promoting cleaner electric power through controls on that sector's carbon dioxide emissions. The ultimate impact of this policy, the Clean Power Plan (CPP), depends upon how states will implement their specific plans. The study finds that this policy could cause a sharp transitory movement towards domestic natural gas use after 2020, at a time when the United States hopes to grow its export market. But natural gas markets appear to have sufficient flexibility to allow greater domestic demand without appreciably changing the outlook for domestic natural gas prices or net U.S. exports.

The study based its assessment on projections made by 16 leading modeling teams in an effort to provide a range of views for energy planning and policymaking. This approach contrasts with many previous energy policy studies, which base their conclusions on a single model that essentially locks policymakers into one view of future market conditions.

The United States imported 1.2 trillion cubic feet (Tcf) more than it exported in 2014. This amount equals 4.9% of the fuel's total deliveries to consumers. By 2020 and beyond, the projections indicate that the natural gas trade balance would reverse with exports outpacing imports. But depending upon the model estimate, the range of net exports is wide – between virtually no net exports to 5 Tcf by 2030 – even when participants used similar energy and economic conditions for a reference case.

Poorly understood U.S. resource basins account for only some of this imprecision. Other uncertain factors include the costs of producing natural gas elsewhere and the costs of other major energy sources, which often varies from one model estimate to another.

When shale gas resources are plentiful and less costly to produce than in the reference case, projected U.S. natural gas prices average about \$1.24 per million Btu lower than under reference conditions. As the United States gains a competitive advantage on the global market, projected net exports will be 2.3 Tcf higher on average. This process is reversed when shale gas resources are more limited and costly to produce.

Methodology may be an important reason for explaining the different estimates. Global models with detailed regional supply sources and demand centers tend to show more competition and lower U.S. export levels than country-level models for the United States alone.

## INTRODUCTION

Over many decades energy markets have seen a variety of new technologies with the potential of replacing existing practices for providing conventional fossil fuels. Synthetic fuels during the 1970s, hydrogen during the 2000s and carbon capture and sequestration in today's climate-change constrained times have all captured the fancy of policymakers. And yet, each of these options has not held much promise to date in being major players in the future energy mix. But since about 2006, hydraulic fracturing combined with horizontal drilling have made substantial in-roads in altering America's energy future by significantly reducing the cost of extracting natural gas from North American shale deposits. The sudden appearance of a cost-effective option that allowed prices to fall below conventional practices was not what many energy analysts had expected since the oil embargos of the 1970s. This new technology is competitive today rather than being a high-cost energy source. This technological innovation has made natural gas a very competitive fuel relative to coal and other sources. Its expansion within North America has replaced considerable coal in the power sector. This shale revolution is hence unlike many previous energy technologies such as synthetic fuels or hydrogen.

Many have called this development, combined with similar trends in finding and developing its sister source of tight oil from shale deposits, as the renaissance of U.S. fossil fuel resources. Although there are environmental and social challenges associated with its development, it appears that American policymakers believe that they can manage and resolve these problems.

To what extent are these new shale sources a renaissance or "game changer" if government policies permit their development? This report summarizes the key findings of an Energy Modeling Forum (EMF) group organized by Stanford

University to evaluate future energy outlooks for alternative perspectives on North American natural gas resource availability. Frequently major energy studies are based upon the results from a single model. The unique feature of this study is that conclusions are drawn from results across multiple models where key input assumptions are similar. Although individual working group members held a range of different views, the general conclusions below apply to the results reported by most of the models.<sup>1</sup>

### The Forum Process

The Energy Modeling Forum formed a working group of about 50 experts and advisors from companies, government agencies and universities. It met four times over the October 2013-May 2015 period. Modeling teams from 16 different organizations participated in the study. The study participants considered nine different cases based upon standardized assumptions.

### This Study's Focus

The study focused on the impacts of shale gas on North American energy markets. The group expanded focus to global conditions to evaluate how competitive U.S. exports would be. Although the shale revolution has stimulated tight oil expansions, this study does not explore these issues because oil is processed and used very differently from natural gas. Many shale gas plays are "wet" with high liquid content, but the study does not cover these products.

### Participating Modeling Teams

Modeling teams from 16 different organizations participated in the full EMF study. The model names and organizations maintaining each framework are reported in [Table 1](#). It is not possible to adequately describe the detailed methodologies of each approach, but readers are referred to available online information about each model shown in the table.

All models integrate information on North American energy supply and demand to provide

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<sup>1</sup> This effort is the second, two-year EMF study that builds upon the previous study summarized in the Energy Modeling Forum (2013).

Table 1. Participating Modeling Teams in the Study

Model	Organization	Type	Global	More Information
ADAGE	Research Triangle Institute	Computable General Equilibrium		<a href="http://www.rti.org/page.cfm?objectid=DDC06637-7973-4B0F-AC46B3C69E09ADA9">http://www.rti.org/page.cfm?objectid=DDC06637-7973-4B0F-AC46B3C69E09ADA9</a>
AMIGA	Argonne National Laboratory	Computable General Equilibrium		<a href="http://amiga.dis.anl.gov/">http://amiga.dis.anl.gov/</a>
CIMS-US	Simon Fraser University	Process-Economy		<a href="http://www.emrg.sfu.ca/Our-Research/Policy-Modelling">http://www.emrg.sfu.ca/Our-Research/Policy-Modelling</a>
DIEM	Duke University	Computable General Equilibrium		<a href="http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_wp_14-07.pdf">http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_wp_14-07.pdf</a>
DIW-Multi-Mod	German Institute for Economic Research (DIW Berlin)	Spatial Equilibrium	X	<a href="http://www.diw.de/multimod">http://www.diw.de/multimod</a>
EC-IAM	Environment Canada	Computable General Equilibrium	X	<a href="http://link.springer.com/article/10.1007/s10584-013-1002-2/fulltext.html">http://link.springer.com/article/10.1007/s10584-013-1002-2/fulltext.html</a>
ENERGY 2020	Systematic Solutions, Inc.	System Dynamics		<a href="http://www.energy2020.com/resources.html">http://www.energy2020.com/resources.html</a>
EPAUS9r-MARKAL	US Environmental Protection Agency	Energy Optimization		<a href="http://nepis.epa.gov/Adobe/PDF/P100I4RX.pdf">http://nepis.epa.gov/Adobe/PDF/P100I4RX.pdf</a>
FACETS	KanORS Inc	Energy Optimization		<a href="http://facets-model.com/multiregion/">http://facets-model.com/multiregion/</a>
GTEM-C	CSIRO, Australia	Computable General Equilibrium	X	<a href="http://www.sciencedirect.com/science/article/pii/S030626191400083X#">http://www.sciencedirect.com/science/article/pii/S030626191400083X#</a>
LIFT-MARKAL	MITRE Corp	Interindustry Macro-econometric Energy Optimization		<a href="http://www.etsap.org/documentation.asp">http://www.etsap.org/documentation.asp</a>
NEB	National Energy Board	Systems Dynamics		<a href="http://www.neb-one.gc.ca/nrg/ntgrtd/ft/2013/ppndcs/rprtmthdlg-eng.html">http://www.neb-one.gc.ca/nrg/ntgrtd/ft/2013/ppndcs/rprtmthdlg-eng.html</a>
NEMS	Energy Information Administration	Process-Economy		<a href="http://www.eia.gov/oiaf/aeo/overview/">http://www.eia.gov/oiaf/aeo/overview/</a>
NERA-GNGM	NERA, Inc.	Spatial Equilibrium	X	<a href="http://www.nera.com/content/dam/nera/publications/archive2/PUB_LNG_Update_0214_FINAL.pdf">http://www.nera.com/content/dam/nera/publications/archive2/PUB_LNG_Update_0214_FINAL.pdf</a>
NETL-MARKAL	National Energy Technology Laboratory	Energy Optimization		<a href="http://www.etsap.org/documentation.asp">http://www.etsap.org/documentation.asp</a>
ReEDS	National Renewable Energy Laboratory	Energy Optimization		<a href="http://www.nrel.gov/analysis/reeds/">http://www.nrel.gov/analysis/reeds/</a>

prices that reach market balances for each of the covered fuels. Four models (DIW-Multimod, EC-IAM, GTEM-C, and NERA-GNGM) provide a global perspective to North American markets by including fuel conditions in all other major world regions or countries. The remaining 12 models focus on national U.S. balances without these global linkages, although many have some simple linkages to a world market for fuels like petroleum or natural gas. All but one models focus on the opportunities to substitute between major fuels (coal, natural gas, petroleum, nuclear and various renewable sources) in the major end-use sectors (residential, commercial, industrial, transportation and electric generation). NERA-GNGM is the exception where the system focuses on the regional competition within global markets for producing and using natural gas.

The models adopt either an economic equilibrium, engineering process, or some blended or hybrid approach for representing energy supply, demand and prices in the United States. Some models focus on the major inter-industry linkages within the economy to determine energy production and consumption. These systems comprise a (general) economic equilibrium system that solves for multiple energy and non-energy markets throughout the economy by maximizing consumer and producer welfare (sometimes also called “surplus”). They project energy demand by tracking the important inter-industry flows within the economy. A series of nested production relationships (functions) allow substitution between different fuel types and labor and capital inputs.<sup>2</sup> An increase in natural gas prices will reduce natural gas consumption by raising the cost of using natural gas relative to other energy sources and by raising the cost of using energy relative to capital and labor inputs. It is often difficult to evaluate the size of this response from available documentation because

substitution responses are imbedded in a series of elasticities and input cost shares that cannot be easily disclosed.

An engineering process approach solves the low-cost strategy for choosing between competing explicit technologies for meeting a similar end-use demand service. An increase in the natural gas price will reduce natural gas consumption as existing equipment is used more efficiently and as new more energy-efficient equipment replaces retiring vintages. Once again, it is challenging to disclose the size of this response, because it is embedded in a series of assumptions about energy end-use services (e.g., temperature control in buildings), appliance size, new equipment costs, new equipment efficiencies, and consumers’ time preference (discount rates).

Most systems are not purely process or economic. For example, ADAGE and DIEM were developed originally as inter-industry equilibrium systems but now include detailed processes for electric generation, a sector that transforms primary energy sources into electric power for delivery to end users. In representing primary fossil fuel supply, AMIGA, NEMS, and MARKAL-NETL track total natural gas resources available for all future years at a disaggregated level and allow that resource base to be extracted over time. Most other models represent production conditions through supply curves that reveal the costs of producing different natural gas volumes in each year.

Decisions will be based upon expectations adapting to recent past experience or complete knowledge about how future events will materialize. Within the general equilibrium systems, ADAGE and DIEM provide complete look-ahead with rational expectations, while GTEM-C solves these decisions sequentially. Many process models allow decisions to incorporate rational expectations over the full horizon of the framework.

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<sup>2</sup> These production relationships are usually constant-elasticity-of-substitution functions allowing

substitution between energy, capital and labor before representing substitution between different energy sources (including electricity).

Table 2. Scenarios Evaluated in the Study

Case	Real Global Oil Price	USA Economic & Demographic Trends	Domestic Natural Gas Resource Costs	Environmental Regulations	Overseas Conditions
Reference	AEO2014: 0.8% per year through 2040	AEO2014: GDP rises by 2.4% per year through 2040	AEO 2014 Reference Resources	No New Regulations, except proposed New Source Performance Standards (NSPS) for CO <sub>2</sub> , prohibiting new coal without CCS	Relax oil indexation in 2025; No specific economic growth conditions imposed
High U.S. Shale Resources	AEO2014: 0.8% per year through 2040	AEO2014: GDP rises by 2.4% per year through 2040	Reduce cost (curves) by 9% (2015) to 40% (2040)	Reference	Reference
Low U.S. Shale Resources	AEO2014: 0.8% per year through 2040	AEO2014: GDP rises by 2.4% per year through 2040	Increase cost (curves) by 6% (2015) to 38% (2040)	Reference	Reference
Technology Performance Standard (TPS)	AEO2014: 0.8% per year through 2040	AEO2014: GDP rises by 2.4% per year through 2040	AEO 2014 Reference Resources	Reduce target for power sector's carbon emission rates by 2% per year through 2050	Reference
TPS with Low Supply	AEO2014: 0.8% per year through 2040	AEO2014: GDP rises by 2.4% per year through 2040	Increase cost (curves) by 6% (2015) to 38% (2040)	Reduce target for power sector's carbon emission rates by 2% per year through 2050	Reference
High Asian Demand	AEO2014: 0.8% per year through 2040	AEO2014: GDP rises by 2.4% per year through 2040	AEO 2014 Reference Resources	Reference	Increase Asian demand gradually by 20% above reference in 2040
High Asian Demand with High Supply	AEO2014: 0.8% per year through 2040	AEO2014: GDP rises by 2.4% per year through 2040	Reduce cost (curves) by 9% (2015) to 40% (2040)	Reference	Increase Asian demand gradually by 20% above reference in 2040
Oil-Indexed Pricing for Asian Gas	AEO2014: 0.8% per year through 2040	AEO2014: GDP rises by 2.4% per year through 2040	AEO 2014 Reference Resources	Reference	Relax oil indexation in 2035
Russian Supplies	AEO2014: 0.8% per year through 2040	AEO2014: GDP rises by 2.4% per year through 2040	AEO 2014 Reference Resources	Reference	Remove Artic supplies; Phase out Ukranian pipelines.

Many of the remaining models solve each year's decision sequentially, but NEMS allows a blended approach where some end-use sectors adapt gradually over time while others look ahead with perfect foresight.

### EMF Scenarios

The EMF working group considered 9 scenarios with some key exogenous information standardized across models as summarized in Table 2. Results from each of the last 8 scenarios can be compared to estimates from the first case (called the "Reference" scenario) to understand the responses of each framework to changed conditions. Conditions that were altered in these other 8 cases include: (1) the cost and availability of U.S. natural gas shale supplies, (2) federal emissions policy for the electric generation sector, (3) the Asian demand for natural gas exports,

(4) Asian contracts for setting the delivered natural gas prices, and (5) the cost and availability of Russian natural gas supplies. The appendix contains the study design that specifies the detailed assumptions used in each case.

The study specified a reference case patterned after the 2014 Annual Energy Outlook reference case released by the U.S. Energy Information Administration, available at <http://www.eia.gov/oiaf/aeo/tablebrowser/>. The study used this scenario as a control case for comparing other scenarios rather than as the preferred outlook prepared by each modeling team. Key exogenous assumptions for the 2012-2040 period in this case include world crude oil prices (Brent) rising by 0.8% per year to reach \$141 per barrel (2012 U.S. dollars) by 2040 and the U.S. economy growing by 2.4% per year. In addition, the U.S. government does not impose any new energy or environmental regulatory

policies after 2013. The single exception with regard to regulatory policy is inclusion of the proposed New Source Performance Standards (NSPS) for carbon dioxide (CO<sub>2</sub>), which effectively prohibits new coal plants unless they have carbon capture and sequestration (CCS). These factors are the principal demand drivers used by the modeling teams and are combined with resource supply conditions represented in each framework to produce market outcomes such as natural gas prices, production, consumption and export/import balances. The discussion focuses principally upon aggregate national estimates due to different regional and sectoral details embedded in each model.

## IMPACTS OF SHALE RESOURCES

### Reference Conditions

The model-comparison exercise was geared primarily towards understanding how major

shifts in market conditions would influence the use of natural gas and other fuels rather than projecting future market conditions. For this reason, an extensive evaluation of results for the reference case appeared less useful than if the group’s focus had been simply on forecasting prices and quantities. Nevertheless, a brief review of reference conditions helps to understand the discussions in following sections. **Figure 1** demonstrates that most modeling teams have calibrated their inflation-adjusted, reference prices (in 2012 dollars) to the NEMS reference projections, as was suggested in the study design. The convergence of price projections in this chart reveals nothing about what these teams might have projected if they had not adopted these assumptions. Meanwhile, total natural gas consumption covering all sectors (**Figure 2**) varies considerably by model, ranging from very modest increases to levels that reach and sometimes exceed twice 2012 levels by 2050.

**Figure 1. Henry Hub Natural Gas Wellhead Price in Reference Case**

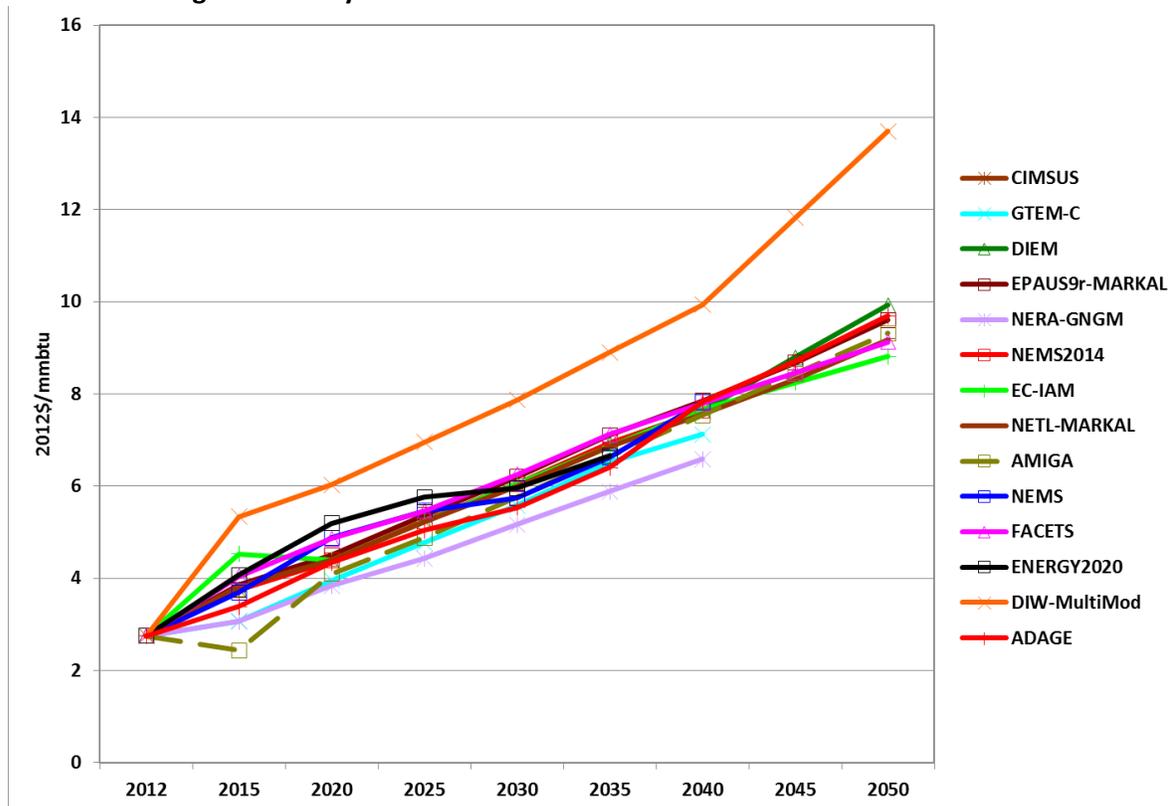
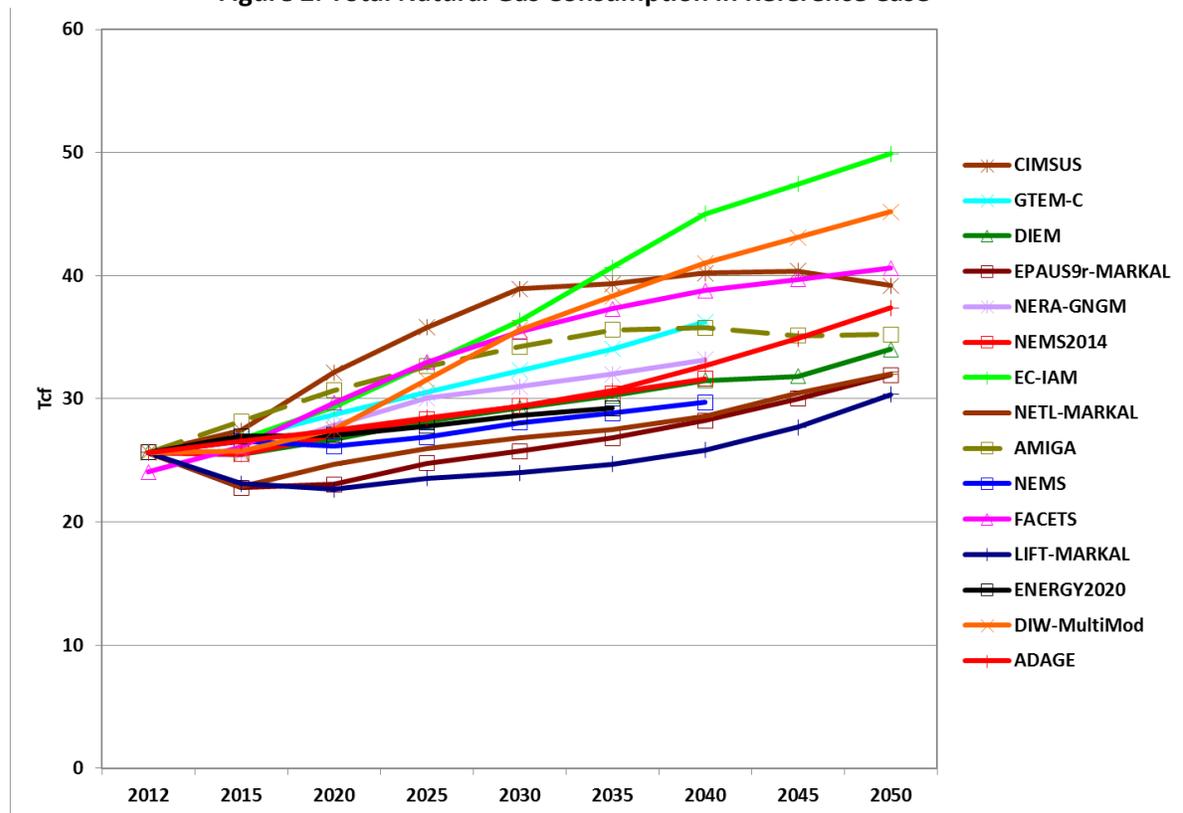


Figure 2. Total Natural Gas Consumption in Reference Case



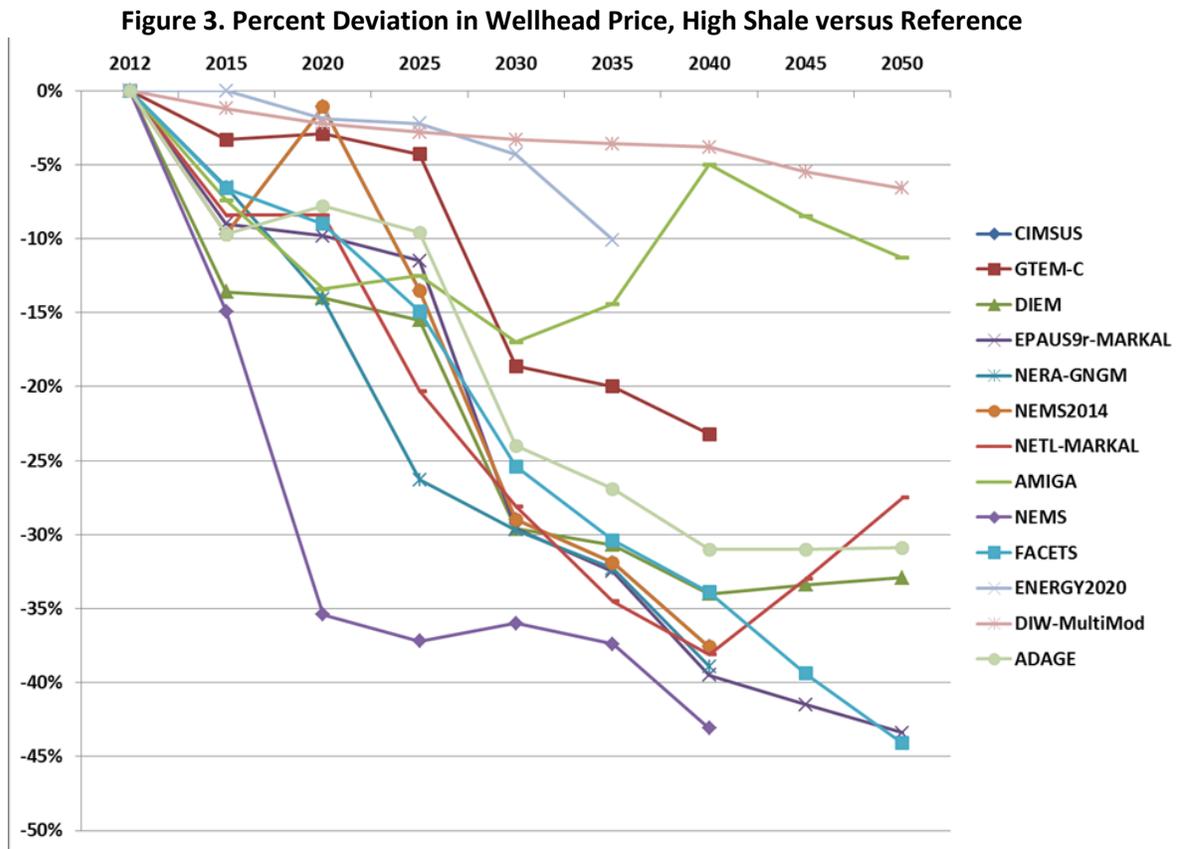
## Energy Price Impacts

The modeling teams considered several different scenarios that changed the cost and availability of natural gas shale resources. The results in this section are based upon a reference outlook and one based upon high-shale-resource conditions. These two cases are patterned after the U.S. Energy Information Administration's Annual Energy Outlook (AEO) 2014 projections for the Reference and High Shale Supply scenarios. The second case allowed higher recoverable resources combined with productivity improvements associated with better well-spacing and other cost reductions. As a result, more resources can be found and at lower costs than in the reference case. Market demand conditions remain the same, except that energy consumption can increase directly as natural gas and other fuel prices change and indirectly as the economy expands.

All models reveal a lower natural gas price resulting from the high-shale supply conditions.

Natural gas prices in most models decline below reference levels in Figure 3 by 25-30% in 2030 and by 30-40% in 2040. Prices decline by noticeably less in about one-third of the models. This figure includes two estimates from the U.S. Energy Information Administration's NEMS model, which produced the AEO results that the other models used for calibrating their initial conditions. Results reported for NEMS2014 refer to the estimates for their 2014 report and are more directly comparable the scenario assumptions adopted by the other models. Results reported for NEMS are the updated estimates based upon this group's more recent views on future energy market conditions.

Important differences exist across models in the amount by which natural gas prices decline because these frameworks have dissimilar perspectives on natural gas market dynamics. When supplies are expanded, natural gas sup-

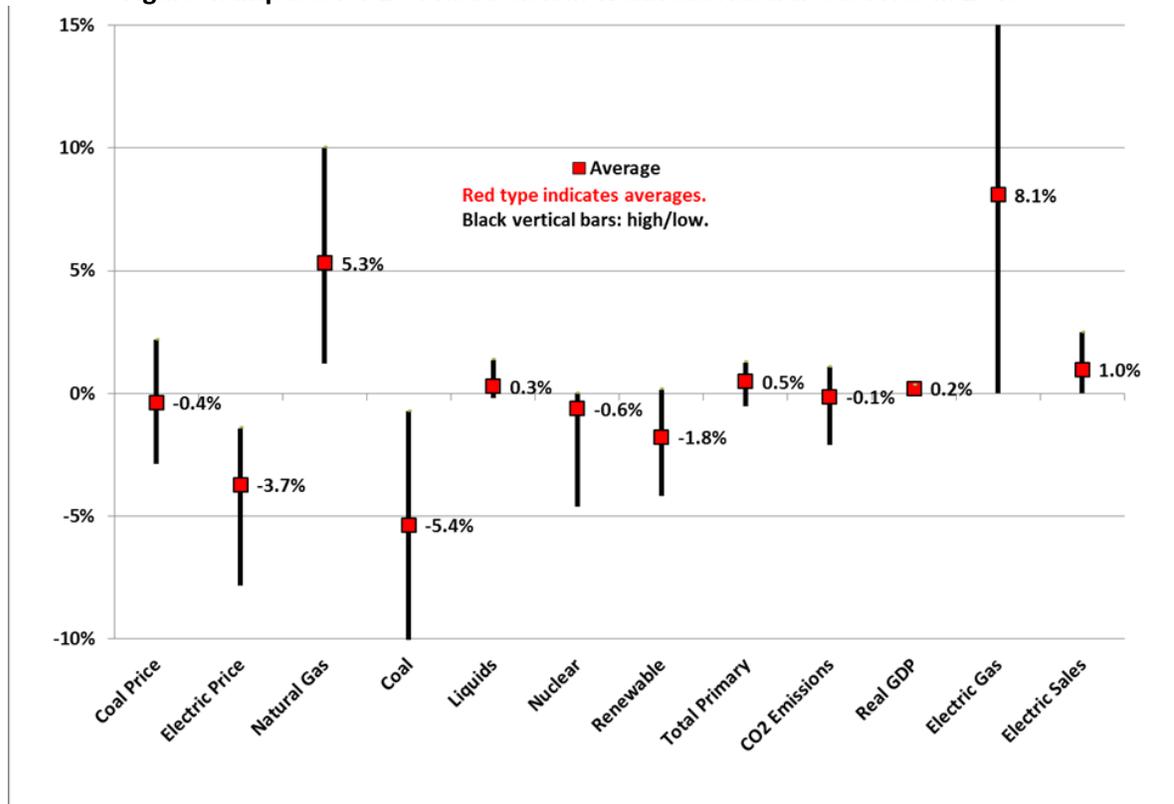


pliers will need to cut prices more when natural gas consumers respond much less to price changes. This effect can be reinforced by producers that are more willing to adjust their production levels than change prices. In general, estimates that anticipate larger natural gas price changes may have larger energy market impacts. For example, more coal may be displaced when natural gas prices decline by more. For this reason, it is more meaningful to discuss the energy market impacts relative to the natural gas price reduction.

Figure 4 shows the major changes in 2040 energy market conditions for each 10% reduction in Henry Hub wellhead prices for natural gas. Instead of reporting the impact on energy

use, carbon dioxide emissions and real GDP due to the high-shale conditions, the chart displays the percentage impact for each variable after it has been divided by the percentage change in natural gas wellhead prices. The vertical bar for each impact listed on the horizontal axis displays the high and low end of the model estimates. The red square indicates the average 2040 impact. Adjusted for inflation, coal mine-mouth prices shown at the far left decline modestly in most models. Lower natural gas prices reduce electric generation costs and retail prices for all customers by 3.7% below reference levels by 2040 on average. Electricity costs and prices decline, but by considerably less than natural gas prices (10%).

Figure 4. Impacts for 10% Reduction in Wellhead Natural Gas Price in 2040



## Fuel Use Impacts

Competition from natural gas tends to reduce the consumption of other energy sources except electricity. Some fuels (coal) have greater carbon emissions per unit of energy than natural gas, while others (nuclear, renewables) have lower carbon emissions. These different fuel use impacts account for some of the differences in the observed shifts in carbon emissions for the models.

### Natural Gas Use Impacts

Lower natural gas prices (reinforced by higher economic growth in some models) induce higher natural gas consumption. Total natural gas consumption rises by 5.3% but this average masks a large difference between 1.2% at the low end and 10.0% at the high end. A significant part of this response occurs within the power sector, whose average natural gas use expands by 8.1% above 2040 reference levels on average

and can be as much as 15.2% higher in one model.

### Coal Use Impacts

Total coal consumption declines by 5.4%, which is comparable to natural gas expansions. This average masks a large difference between -0.7% at the low end and 10.9% at the high end. Coal use reductions are also concentrated within the power sector.

### Liquids Use Impacts

Total liquids consumption remains virtually the same as reference case but it rises by as much as 1.4% in two models that allow more oil-gas substitution in some industrial activities (chemicals and refineries).

### Nuclear Use Impacts

Total nuclear consumption remains the same unless the model allows new nuclear construction in the reference case. Lower natural gas prices prevent the construction of these new plants in the high-shale case.

### ***Renewable Energy Use Impacts***

Renewable energy use includes solar and wind applications but excludes hydroelectric generation. Many solar and wind applications use natural gas generation as a backup source during periods of their intermittencies. Cheaper natural gas can substitute for renewable energy or can stimulate more renewable use by reducing backup capacity costs.

Cheaper natural gas displaces renewables on balance in the projections. Renewable energy use declines more than nuclear but less than coal consumption. Total renewables decline by 1.8% below reference levels when averaged across all models. This average masks large differences between models, ranging from -4.2% to +0.2%.

### ***Electricity Sales Impact***

Electricity sales increase modestly (1.0%) as generation costs decline with lower natural gas prices. Although electricity is less expensive, direct natural gas users also benefit and may lead to switching away from electricity towards natural gas in a number of applications. The electrification trend due to more and cheaper natural gas for the power sector is relatively modest relative to the expansion in total natural gas consumption by electric generators and direct users.

### ***Total Primary Energy Use Impacts***

Total primary energy consumption increases by 0.5% above reference values. Although the primary effect of more available natural gas displaces other fuels, lower natural gas and electricity prices encourage more total energy use.

## ***Economy-wide Impacts***

### ***Shale Gas and Economic Recovery***

Some U.S. industry has responded enthusiastically to these new shale gas opportunities (e.g., see Citi GPS, 2012, and Credit Suisse, 2012). In addition to the oil and gas drilling sector and the various sectors supporting it, the chemical industry now plans major investments within North America to take advantage of lower priced natural gas, ethane and other important liquids

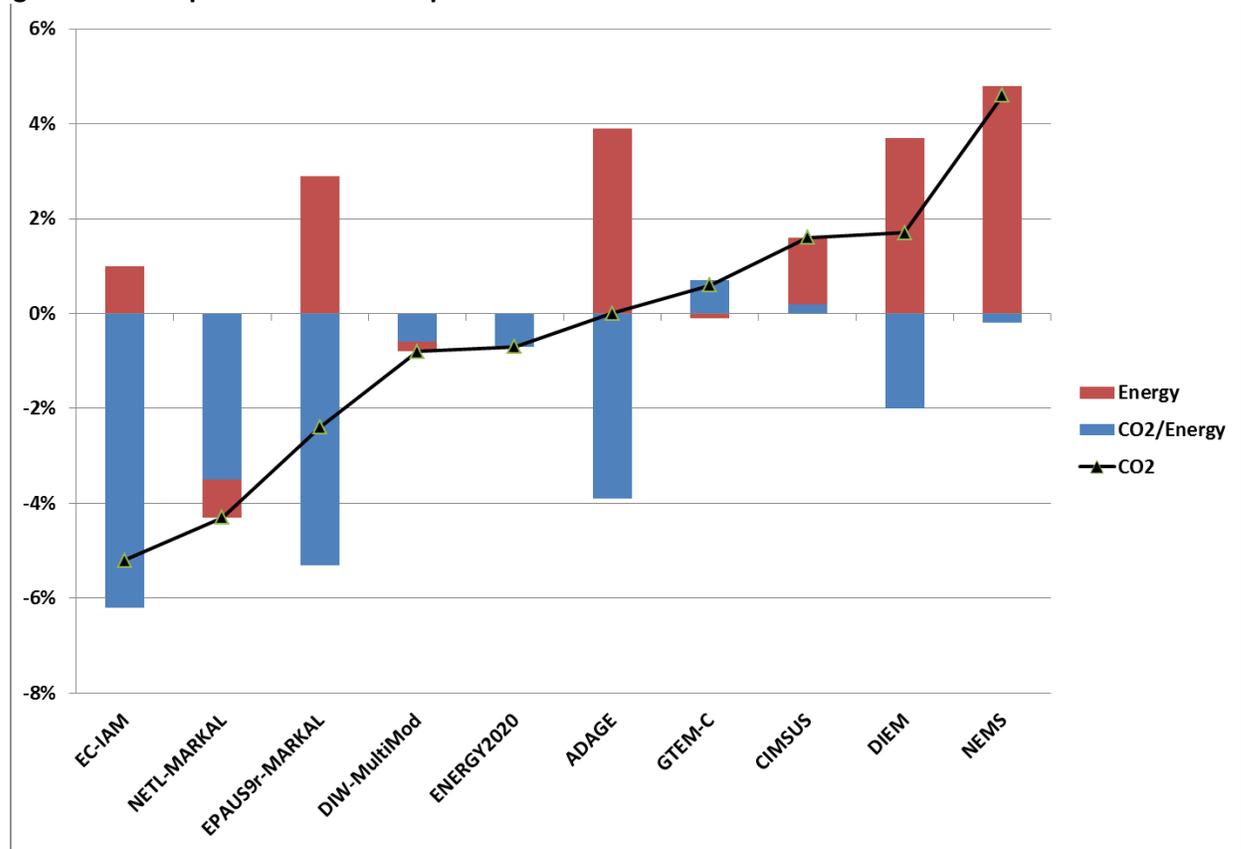
emanating from natural gas sources. The expanded natural gas supplies have also made electric power more competitive in regions where regulations allow gas-fired plants to set electricity prices. The lower costs and increased domestic investment represent significant gains for these industries and for states like Pennsylvania, Texas and Wyoming. However, they shape aggregate economic conditions in a more muted though positive way, because natural gas expenditures in 2014 represent only about 1% of the total U.S. economy. On average, relative to reference conditions, inflation-adjusted Gross Domestic Product in the EMF results eventually rise by .23% for each 10% reduction in natural gas prices due to expanding supplies. NEMS reveals the largest GDP impacts of 0.3% for every 10% decrease in natural gas wellhead prices. LIFT-MARKAL also indicates a relatively larger GDP gain in the high-shale case than other models, although no price elasticity could be computed because it did not report a natural gas price.

### ***Shale Gas and Climate Change Policy***

Although expanding natural gas supply displaces more coal than any other fuel, future downstream U.S. carbon dioxide emissions do not decline by much in the projections discussed by the EMF group. Relative to reference conditions, downstream emissions can either increase or decrease from reference levels, averaging only a -0.1% reduction in 2040.

The shift away from carbon-intensive towards cleaner energy sources appears to account for much of the largest CO<sub>2</sub> reductions caused by greater availability of shale resources. Figure 5 organizes the 2040 results by the deviation in total carbon dioxide emissions from reference values, with the largest reductions shown on the left side. This fuel-switching effect within primary energy (labeled as CO<sub>2</sub>/Energy) in the first three models outweighs any deviations in total primary use (labeled as Energy) resulting from lower prices and/or higher real GDP. Two of the three results are based upon MARKAL models that emphasize the competition between technologies.

Figure 5. Decomposition of Shale Impact on CO2 Emissions in 2040



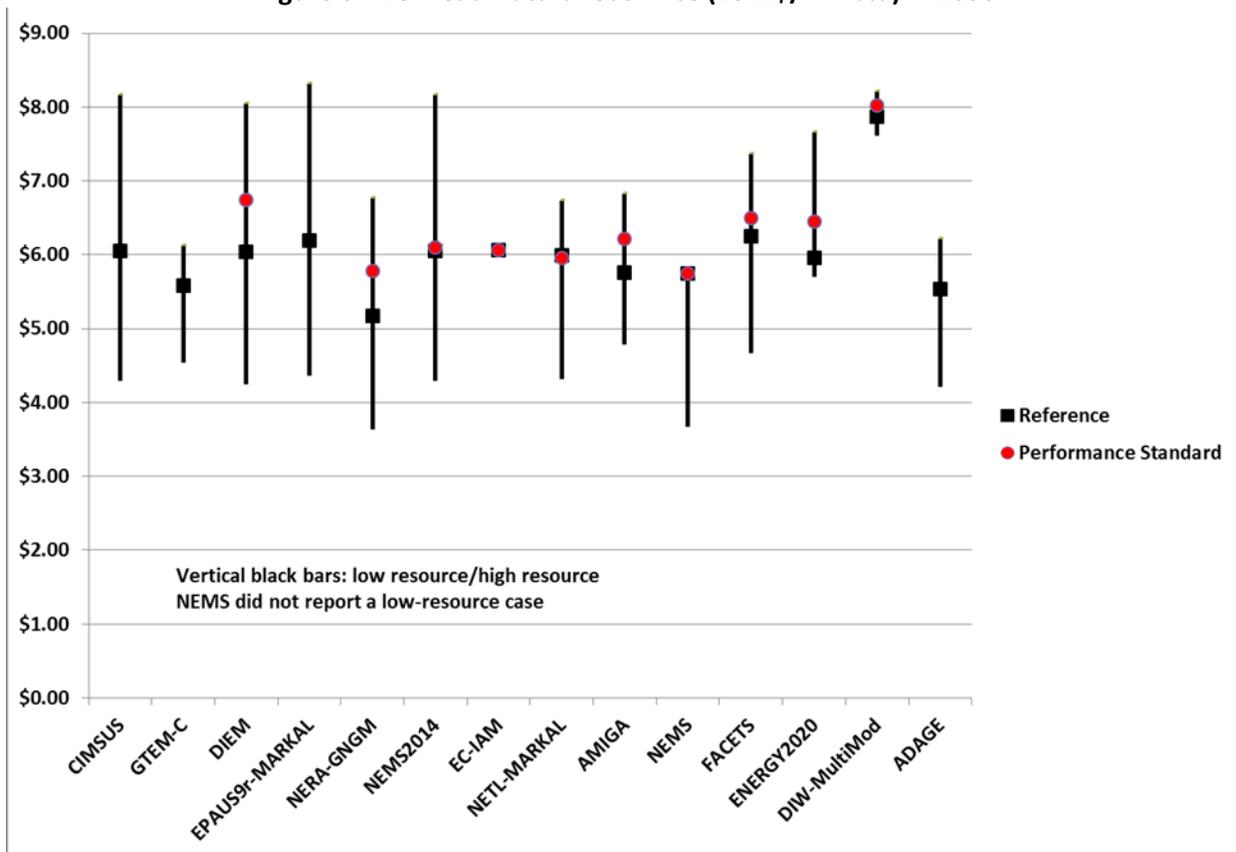
The five results displaying zero or positive carbon emission deviations are from models that allow a faster-growing economy to stimulate more emissions. Three of these five models use general equilibrium economic frameworks, while CIMS is calibrated to the NEMS approach. Modeling approach appears to have a significant role in explaining differences in the projections of carbon dioxide emissions in this study.

These mixed results suggest that the natural gas shale revolution is not a substitute for coordinated climate change policy if governments want to mitigate future greenhouse gas emissions significantly below current levels. Later sections of this report will discuss emissions impacts resulting from a technology performance standard applied to the electric generation sector.

## PROSPECTS FOR AMERICAN NATURAL GAS EXPORTS

A wide natural gas price differential currently exists between North America and other major demand centers in Europe and Asia. The United States has approved several LNG export facilities, and contracts have been signed to transport surplus production across the sea to some of these centers. Near-term market conditions provide a window of opportunity for a few exporting projects. Future growth in American exports will depend upon how competitive domestic supplies will be on the global market. This section describes the price paths in several cases before considering the impact that these prices

Figure 6. Wellhead Natural Gas Price (2012\$/mmbtu) in 2030



have on competitive future levels of U.S. natural gas exports.

Wellhead natural gas prices in the United States rise from their 2014 level of about \$2.75 per million BTU in the EMF projections. By 2030, Henry Hub natural gas wellhead prices in the Reference case, shown by the black squares in Figure 6, often hover around \$6 per million BTU (2012 \$). Across all models they average \$6.01. Demand growth lifts production levels over time. Despite productivity improvements, expanded drilling and exploration requires the development of more expensive supply sources than available in 2014. However, although U.S. natural gas wellhead prices are higher than their 2014 level, they remain below the international crude oil price (on a BTU basis) as well as Asian and European delivered natural gas prices.

Resulting prices will range widely depending upon one’s views on the availability and find-

ing costs of new shale supplies. Higher shale supplies push wellhead prices lower, into the \$4 and \$5 range by 2030. Across all models U.S. wellhead prices average \$1.24 per million Btu below reference levels in 2030. These trends widen the price gap between the United States and other major natural gas markets. Operating in the other direction, lower shale supplies raise wellhead prices, into the \$7 and \$8 range by 2030. U.S. wellhead prices average \$1.17 per million Btu more than their reference levels in the low-shale case. These trends are revealed for each model by the vertical bars in Figure 6.

The next major section describes in much greater depth a Performance Standards case in which the electric sector is required to adopt cleaner generation sources. These conditions raise 2030 wellhead prices above reference levels in some projections but leave them unchanged in others. These are indicated by the red

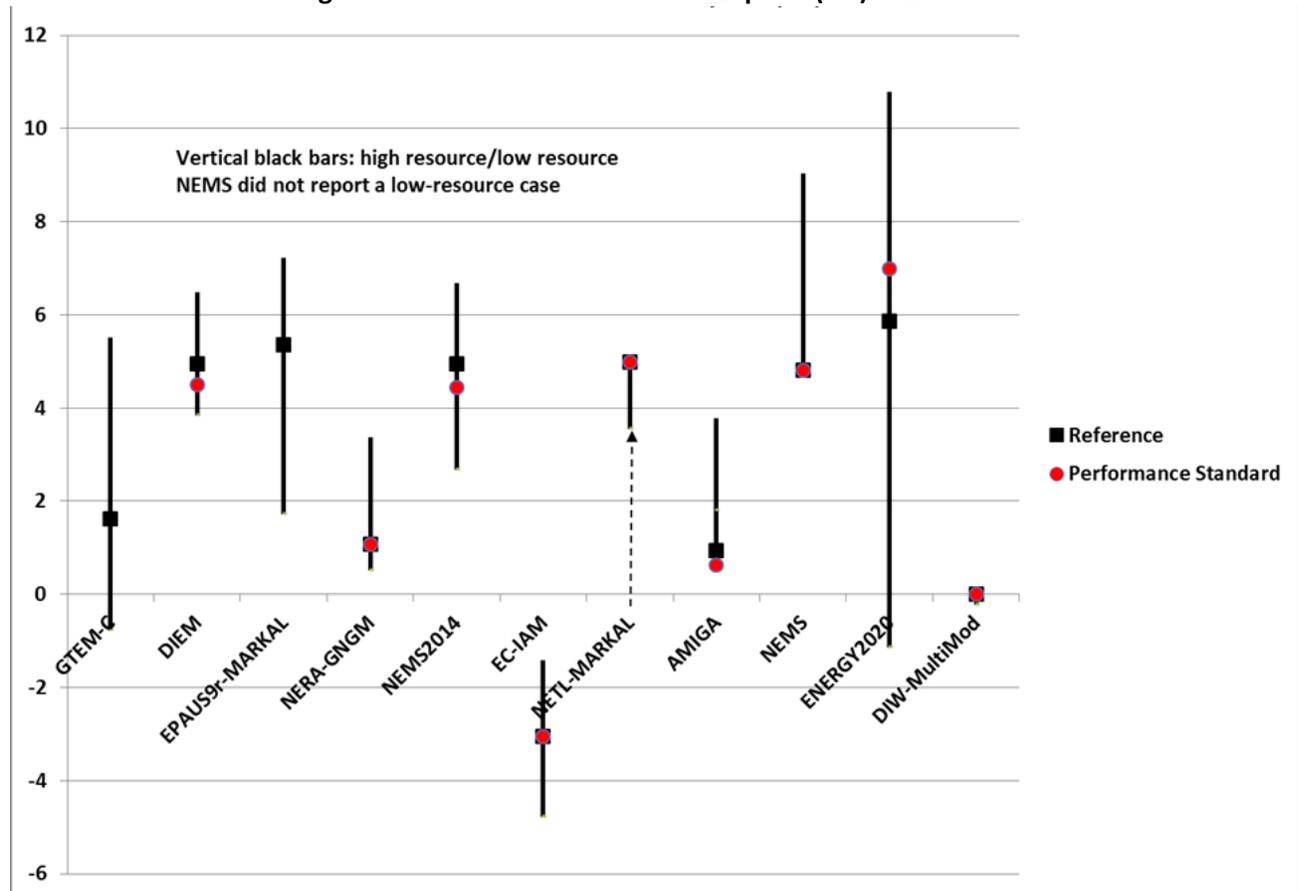
circles in Figure 6. Natural gas could play an important role in meeting the targets in the 2020-2030 period because of its comparatively lower emissions intensity. If additional natural gas demand within the electric power sector can be met with large expansions of natural gas supply at only slightly higher costs, U.S. natural gas prices will not rise much. Similarly, if existing users switch from natural gas rather than pay higher prices, there will also be little pressure for prices to rise much. Prices and exports (see below) in DIW-Multimod do not change much across different cases because the power sector can rapidly replace units that use coal with gas-fired power plants as shale gas resources expand, with the U.S. exporting residual domestic coal instead of more costly LNG.

U.S. natural gas trade balances reverses, with the country becoming a net exporter under reference conditions in most projections. Net exports (both pipeline and LNG) expand to 2.6 Tcf on average by 2030. They grow strongly in about half the models shown by black bars in Figure 7, reaching 4 to 6 Tcf by 2030. Other projections indicate much more modest increases. Included in this second group are the three international natural gas models – GTEM-C, NERA-GNGM and DIW-Multimod – that represent the U.S.’s competitive position with many other supply regions within a global market. Adding LNG infrastructure costs for collecting, processing, liquefying, shipping and regasifying to the wellhead cost often make U.S. export volumes uncompetitive relative to sources delivered from other supply regions like Australia, Africa and the Middle East in these models. This cost disadvantage appears to hold in these frameworks even though U.S.

### Shale Gas and Natural Gas Exports

Net natural gas imports into the United States were about 1.2 Tcf in 2014. By 2020 the

Figure 7. Total US Net Natural Gas Exports (Tcf) in 2030



LNG projects tend to be previously used and less expensive “brownfield” facilities. Regulators in these Asian and European countries may allow some of the LNG costs to be passed through to “core” customers with limited ability to purchase other supplies, but opportunities to attract more competitive, “non-core” customers appear limited. When opportunities for expanding LNG trade to Asia and Europe are limited, US producers may find a more attractive market by looking to its North American neighbor, Mexico. If that country expands its gas-fired power generation but fails to adopt the institutions for encouraging more domestic drilling, it may become an important destination for U.S. supplies in the longer term.

U.S. LNG exports should penetrate global markets more if future U.S. natural gas supplies become more abundant and less costly than expected under the reference conditions. More abundant U.S. supplies initially widen the price gap between the United States and both Europe and Asia, relative to other supply regions participating in the LNG market. When companies add the required LNG infrastructure, the US improves its competitive advantage. If U.S. supplies become less plentiful than in the reference case, the international price gap shrinks and U.S. exports become less competitive. The vertical bars in [Figure 7](#) indicate that exports often extend several Tcf above these reference levels with high-shale supply conditions (averaging 2.3 Tcf) and several Tcf below them with low-shale supply conditions (averaging 1.9 Tcf). These results underscore the futility of predicting future US export activity in a world with large supply uncertainties.

Export volumes with performance standards (indicated by red circles) are often similar to their reference counterparts. Although higher U.S. prices will increase exports through more domestic production, higher domestic consumption from greater powerplant use will decrease exports.

## Higher Asian Demand for Natural Gas

Asian demand centers could become an important market for U.S. suppliers. Natural gas would be liquefied, transported and regasified through LNG facilities. The study considered a case where Asian natural gas demand grew more rapidly than in the reference case. These conditions included annual Chinese coal use for electric generation growing by 1% per year less than in the reference case through 2050 due to exogenous policies. Additionally, annual Korean nuclear use grows by 1% per year less than in the reference case through 2050 due to exogenous policies. Asian policymakers did not impose any additional regulatory restrictions on other fuels (like renewables) that did not already exist in the reference case. This case effectively shifted the preferred demand for natural gas in Asia gradually to 20% above reference levels by 2040. This shock translates to about 6% of the world gas demand outside the USA in 2040.

## Impacts on U.S. Exports

The large capital costs associated with liquefying, shipping and regasifying natural gas over very long distances makes it difficult for the United States to expand its exports to meet this additional demand. Higher Asian natural gas demand is satisfied largely by other supply sources.

[Figure 8](#) displays the responses for several models due to the higher Asian demand with reference U.S. supply conditions. The higher Asian demand has the largest impact in NERA-GNGM, increasing total U.S. exports by 0.7 Tcf in 2020 and by 1.2 Tcf in 2040. EC\_IAM shows a similar impact in 2040. Natural gas trade flows change considerably less in the other two models.

The muted natural gas export response in the DIW-Multimod model provides an interesting contrast. World coal producers compete more vigorously with natural gas exporters in the DIW model than in the other models. (The NERA-GNGM framework explicitly excludes these

Figure 8. Deviation in Total Net Exports (Tcf) in High Demand versus Reference

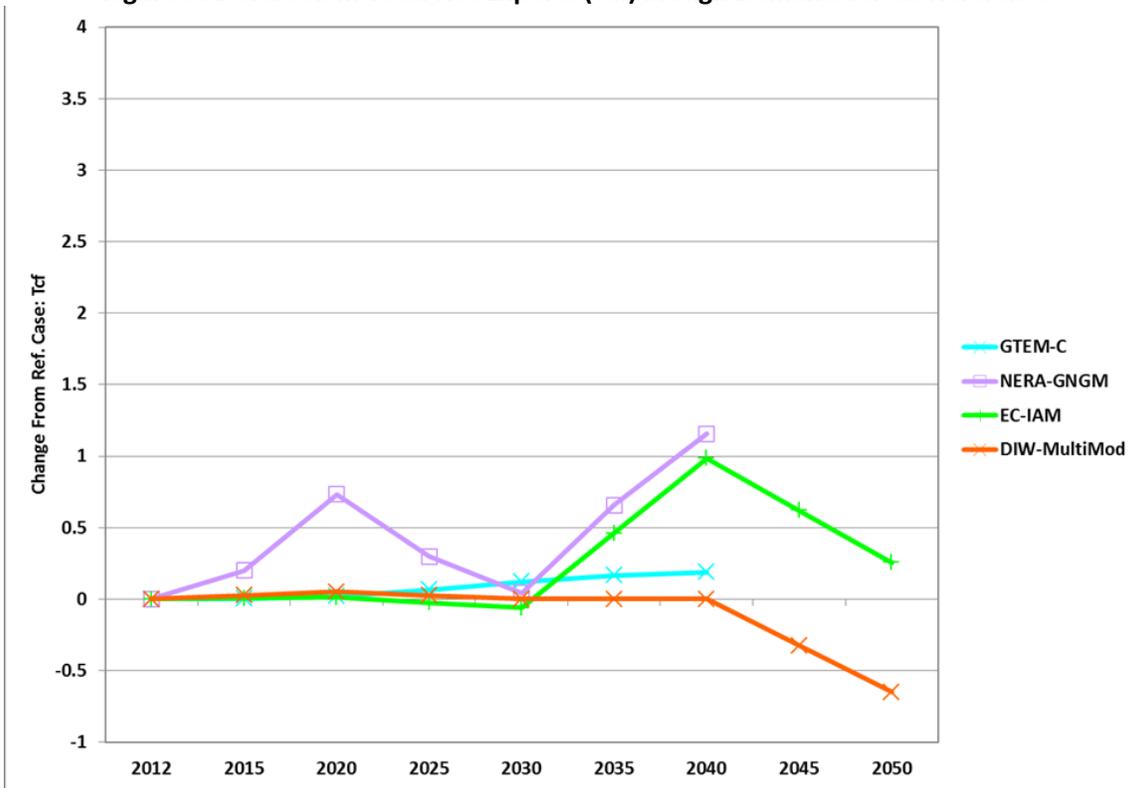
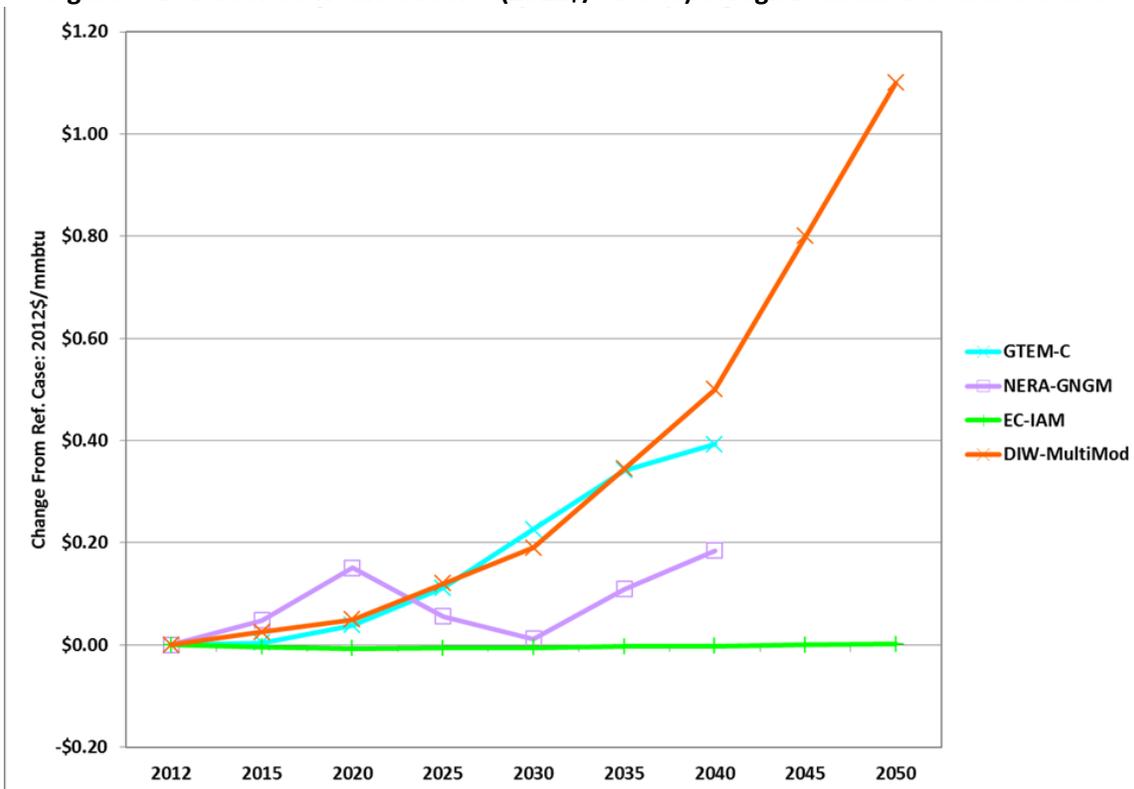


Figure 9. Deviation in Wellhead Price (2012\$/mmbtu) in High Demand versus Reference



other fuel markets in order to provide greater depth on the dynamics within the global natural gas market.) Net natural gas exports in the DIW model decline below reference levels after 2040. As Asian consumers replace coal with natural gas, coal producers begin to search for other markets. Coal exports begin to compete in other end-use markets serviced by U.S. gas exports, causing a decline overall in net exports relative to the reference case.

### Impacts on U.S. Natural Gas Prices

With increases in net exports of less than 1 Tcf above reference levels as explained above, Figure 9 shows that wellhead prices do not rise by more than \$0.20 per million Btu through 2030. Additional volumes can be gathered for the export market by reallocating some gas from domestic uses and by encouraging more production. After 2030, wellhead price impacts become larger and reach about \$0.40 per mmBtu by 2040 in several models.

### Impacts on U.S. Exports with more Plentiful U.S. Supply

If natural gas shale supplies should become more plentiful within North America, natural gas prices will be lower and the U.S. market will become a more important supplier in the world market. There exists considerable policy interest in the additional impacts of higher Asian demand if the USA should find itself in high-resource rather than in reference supply conditions. Figure 10 shows the amount by which net exports increase above levels obtained in the high-resource case.

NERA-GNGM export levels increase strongly above the high resource case when Asian demand increases. Exports in the other models do not change as much with more plentiful total supplies. U.S. production within this second group does not become much more competitive for Asian markets even at the lower wellhead prices prevailing in the high-resource conditions.

### Impacts on U.S. Natural Gas Prices with more Plentiful U.S. Supply

The previous section emphasized that wellhead prices decline by as much as \$2 per million BTU with more plentiful supply conditions. Figure 11 shows the amount by which higher Asian demand increases inflation-adjusted wellhead prices above levels obtained in the high-resource case. Inflation-adjusted wellhead prices rise by less than \$0.20 per million BTU through 2030 and by less than \$0.30 by 2040. This price result happens even in NERA-GNGM, despite its stronger export quantity response in Figure 10.

## IMPACTS OF UTILITY TECHNOLOGY PERFORMANCE STANDARDS (TPS)

### Shale Gas and Plans for Cleaner Power

The potential for US LNG exports will also depend upon what other domestic uses for natural gas develop over this period. The U.S. Environmental Protection Agency (2015) recently promulgated a Clean Power Plan to reduce carbon pollution from the power sector by 32% from 2005 levels. It operates at the state level and sets targets for carbon dioxide emissions within the electric power sector but ignores emissions in other sectors. The emissions rate target would have to be met on average across all existing, and possibly new, fossil generators, not by each individual unit. The target allows credits for energy efficiency improvements and non-hydroelectric renewable generation that can be traded to achieve the standard.

The EMF Working Group quickly realized that this plan could produce very different market outcomes depending upon how it was implemented: which units would be covered and the amount of coordination between states that could be achieved. Reflecting this uncertainty, participants elected to evaluate a “generic” technology performance standard (TPS) with extensions to the emissions targets beyond 2030. Depending upon its implementation, this policy could cause electric generators to shift their fuel

Figure 10. Deviation in Total Net Exports (Tcf) in High Demand with High Resources

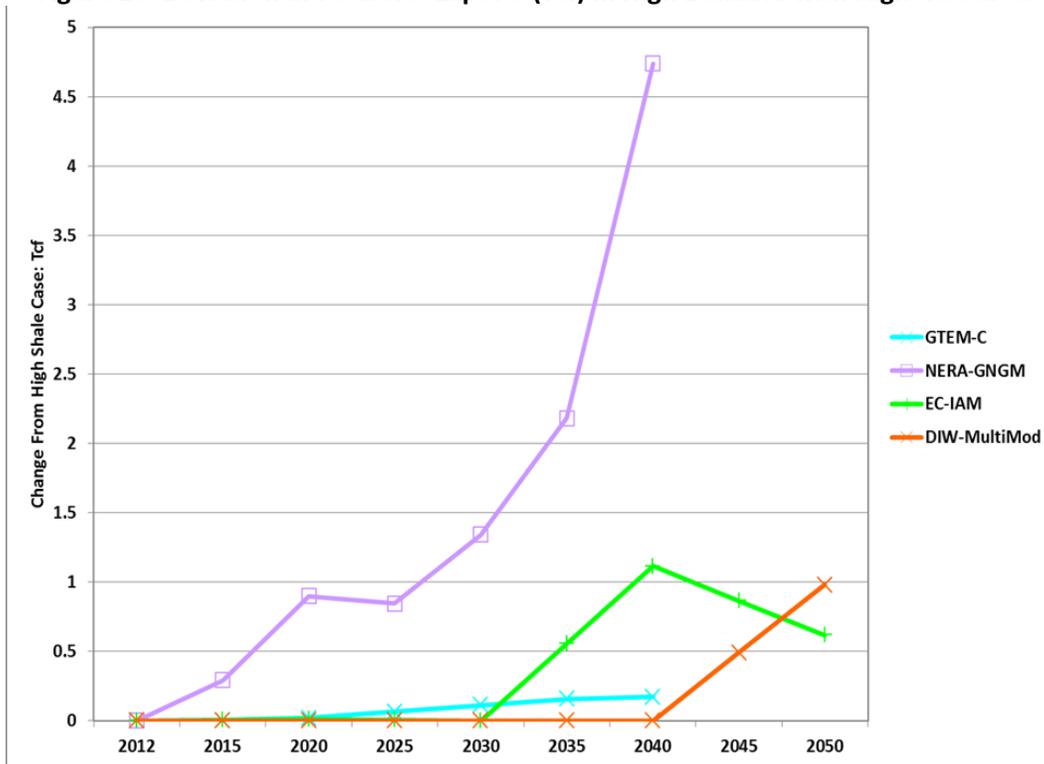
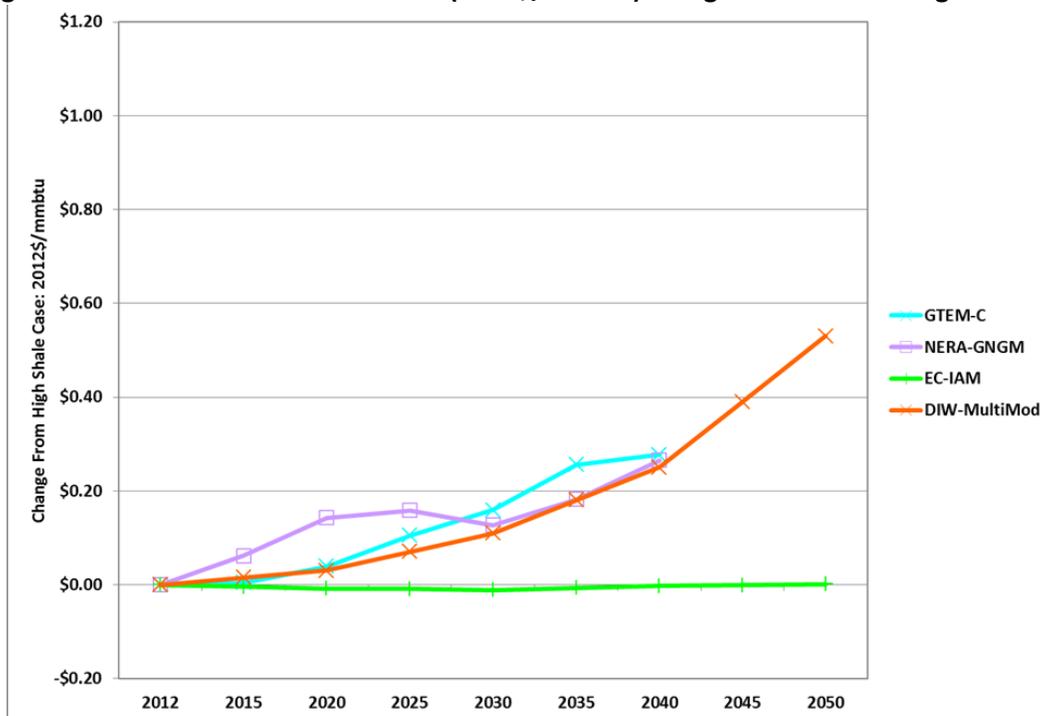


Figure 11. Deviation in Wellhead Price (2012\$/mmbtu) in High Demand with High Resources



use towards natural gas during the 2020-2030 period, when current investment plans call for expanding US LNG exports. A conflict might emerge between the nation's goal of exporting more natural gas and its commitment to constrain carbon emissions in the electric power sector under proposed federal policies.

### Technology Performance Standards for Electric Generation

The Clean Power Plan (CPP) would restrict electric generators from using carbon-intensive sources, especially coal. The Plan adopts technology performance standards (TPS) that require the utility sector to meet a target rate of carbon dioxide emissions intensity for all generation sources rather than each specific fuel type and plant individually. Although the success of this plan will depend upon many factors, an important consideration appears to be the future state of U.S. natural gas market conditions. The EMF study included several scenarios that explored this issue. The TPS rules described below were imposed for both the reference and low shale supply cases developed by the EIA in their AEO2014 outlook.

Regulators recently finalized the CPP rules. The original design of the EMF study, however, has captured the basic essence of the updated Final Rule by specifying a "generic" TPS case. This case is patterned after the June 2014 proposal for the EPA Clean Power Plan, although not all possibilities under either the proposed or final rule have been fully specified and considerable latitude exists in how each individual state will implement the plan within its borders. The TPS standard investigated sets a fleet average CO<sub>2</sub> emissions rate standard (tons/MWh) across all existing and new fossil generators and allows trading of credits to achieve the standard. A generator earns (owes) a credit on each MWh of generation for each ton/MWh that its emissions rate is below (above) the standard. The EMF study's TPS policy covers all new and existing powerplants beginning in the year 2020. The national target emissions rate for these plants was capped at 1001 pounds of CO<sub>2</sub> per megawatt-

hour in 2030 (30% below the average emissions rate for carbon-generating plants in 2005). Included in the megawatt-hour generation were all fossil fuels, all non-hydroelectric renewables, and only those existing nuclear plants classified as under construction or "at risk" plants. Hydroelectricity, energy efficiency and remaining nuclear plants were excluded. After 2030, the case assumes that new policies will be implemented such that the national target CO<sub>2</sub> emissions rate for these plants should decrease by 1% per year to reach a level of 819 pounds per megawatt-hour by 2050. The policy allows the banking of credits for use in future periods.

### Aggregate Natural Gas Impacts of TPS Rules

The TPS rules provide additional domestic demand for natural gas, particularly during the 2020-30 period. Average inflation-adjusted wellhead prices move forcefully above reference levels in DIEM and NEMS during the early years of this policy, as revealed in [Figure 12](#). Although the upward price responses in other models are more gradual, wellhead prices may be as much as 50 cents per million BTU above reference levels during this period. Total natural gas consumption also tends to increase during this period, often reaching 1 to 3 Tcf above reference levels as shown in [Figure 13](#).

These results indicate that the TPS rules may provide favorable terms for natural gas producers, at least during the 2020-30 period. By raising prices in this period, however, this policy may cause a conflict between the nation's goal of exporting more natural gas and its commitment to constrain carbon emissions in the electric power sector.

### Utility Fuel Use Impact of TPS Rules

Performance standards displace coal within the power sector, but by varying amounts. [Figure 14](#) emphasizes that the strongest coal displacement occurs in Energy2020, EC-IAM, DIEM and NETL, while LIFT-MARKAL, REEDS and CIMSUS display the smallest displacement. The average coal displacement in 2030 across all models equals 5.0 quads.

Figure 12. Deviation in Natural Gas Price in Performance Standard versus Reference

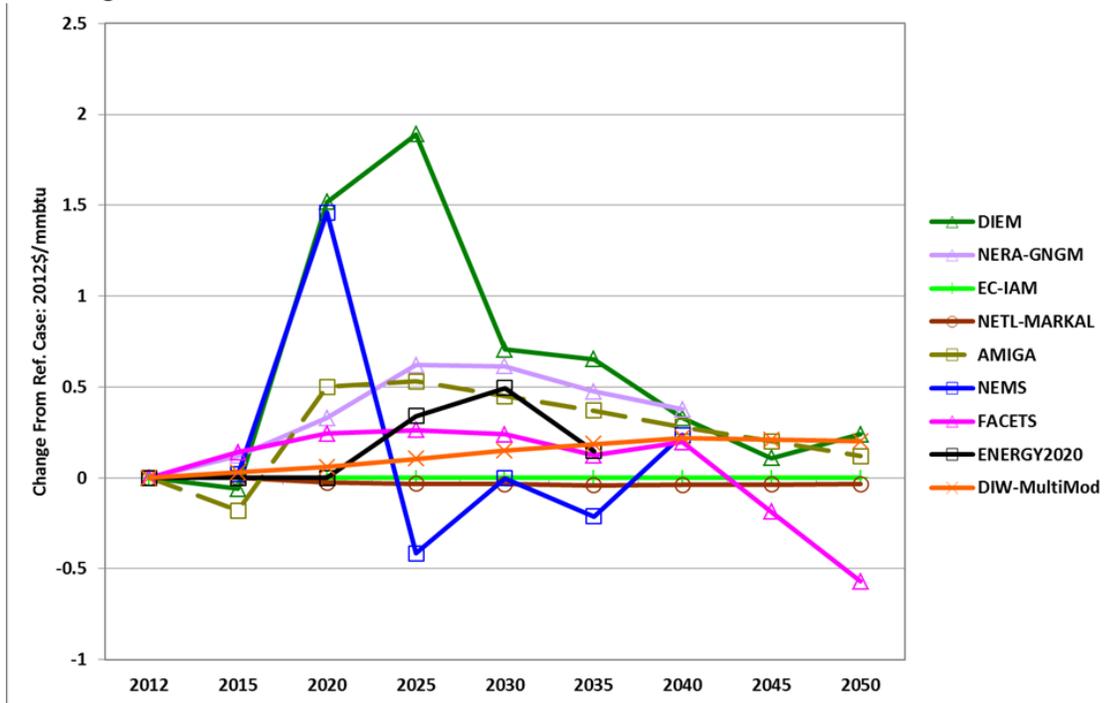
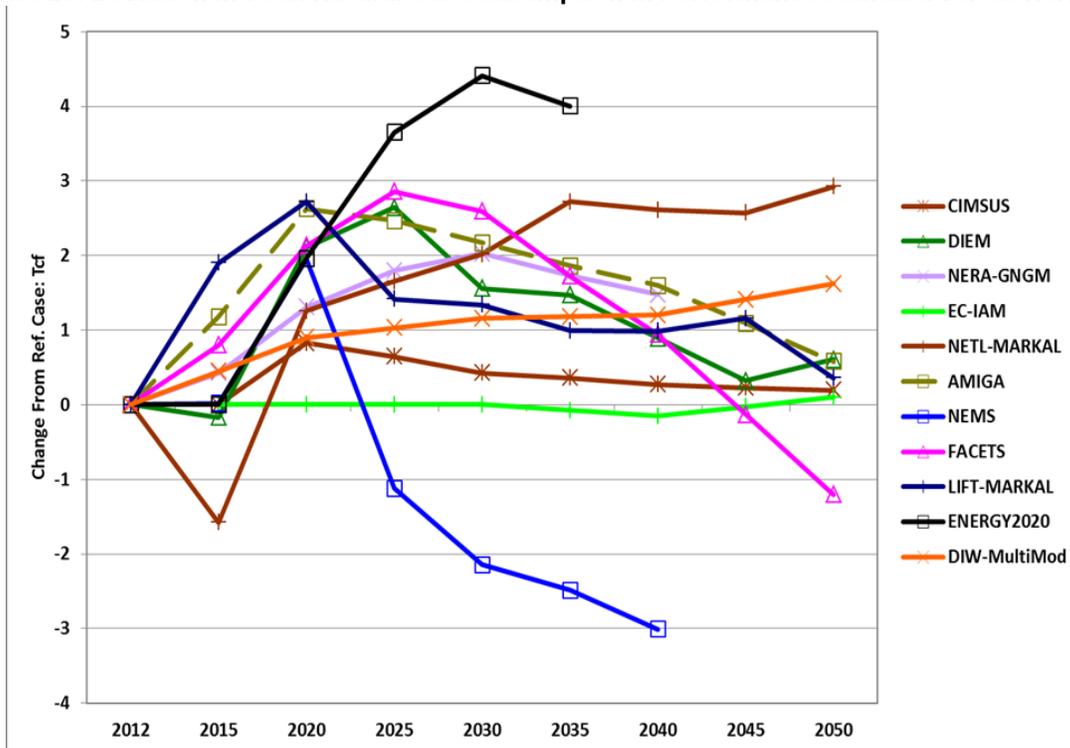


Figure 13. Deviation in Total Natural Gas Consumption in Performance Standard versus Reference





Performance standards expand natural gas within power sector by 2020 as shown in [Figure 15](#). This effect weakens noticeably in most projections as utilities choose other sources in later years. By 2025 natural gas use is lower than reference in NEMS because natural gas becomes very expensive. The average natural gas expansion in 2030 due to performance standards equals 1.9 quads.

In [Figure 16](#) expanded nuclear use contributes importantly in the power sector's response to performance standards in NEMS and FACETS. The response is minimal in other models. The average nuclear expansion for all models in 2030 equals only 0.2 quads.

[Figure 17](#) emphasizes that renewables are an important additional source in NEMS and DIEM. The average renewable expansion in 2030 equals 0.7 quads.

### CO<sub>2</sub> Reference Paths

Total CO<sub>2</sub> emissions for all sectors in 2014 are about 10% below 2005 levels. Within the electric sector, CO<sub>2</sub> emissions in 2014 are about 15% below 2005 levels. Future trends in the reference projections are compared in [Figure 18](#), which shows that total CO<sub>2</sub> emissions for all sectors are relatively flat. By 2030, they return to 2005 levels in two models but remain 5-12% below 2005 levels in other models. The results indicate that some of the reduction below 2005 levels would happen even without the TPS.

### CO<sub>2</sub> Paths with the TPS

TPS reduces CO<sub>2</sub> emissions below reference levels in all models. The trends in [Figure 19](#) indicate that total CO<sub>2</sub> reference emissions for all sectors in the economy decline from 2014 levels for most models. As a result, they remain well below 2005 levels in all models in the future. The policy requires utility sector emissions to reach 30% below 2005 levels in 2030, but does not control other sector emissions.

TPS reduces GDP in all models that report GDP responses to the policy. [Figure 20](#) shows

GDP losses along the vertical axis and CO<sub>2</sub> emission reductions along the horizontal axis due to TPS for three models that report this information. Average GDP costs equal \$53-\$62 (2014\$) for each metric ton reduced economy-wide in 2030. These estimates are averaged across all emissions reductions rather than associated with the last incremental or marginal ton of abatement. GDP losses from TPS become smaller over time and eventually become GDP gains in DIEM and NEMS.

### Natural Gas Impact with Low Shale Supply

The utility sector continues to use more natural gas to meet the performance standard targets when shale resources are more limited and costly to produce. In [Figure 21](#) electric gas use expands by less with more limited shale supply than with reference conditions in 2030 in more than half the models (DIEM, REEDS, AMIGA, FACETS and LIFT-MARKAL) but usually by less than 1 quadrillion BTUs.

### CO<sub>2</sub> Paths with the TPS with More Limited Gas Shale Supplies

Gas-fired units would be more expensive to operate if shale supplies are more limited. Under these conditions, the 2030 utility targets would become more costly to reach by shifts towards natural gas alone. Meeting the emissions targets under these conditions would require greater reliance upon other fuels. Although emissions are regulated within the power sector only, there is policy interest in what happens to emissions for the aggregate economy. [Figure 22](#) shows that total CO<sub>2</sub> emissions levels for the economy decline by similar amounts for performance standards with either reference (red bars) or low shale supply conditions (blue bar). By 2030, they lie 13-20% below 2005 levels in 5 of the 6 models.

Figure 16. Impact of Performance Standard on Electric Nuclear Use (Quad Btu)

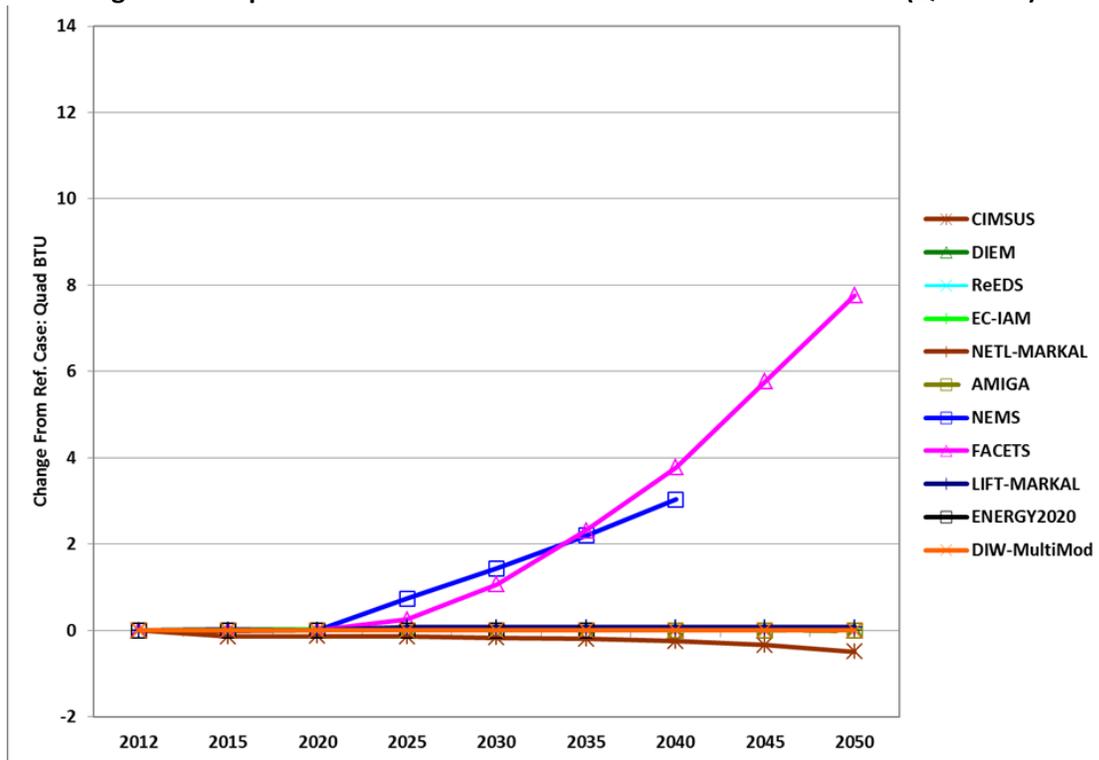


Figure 17. Impact of Performance Standard on Electric Renewable Use (Quad Btu)

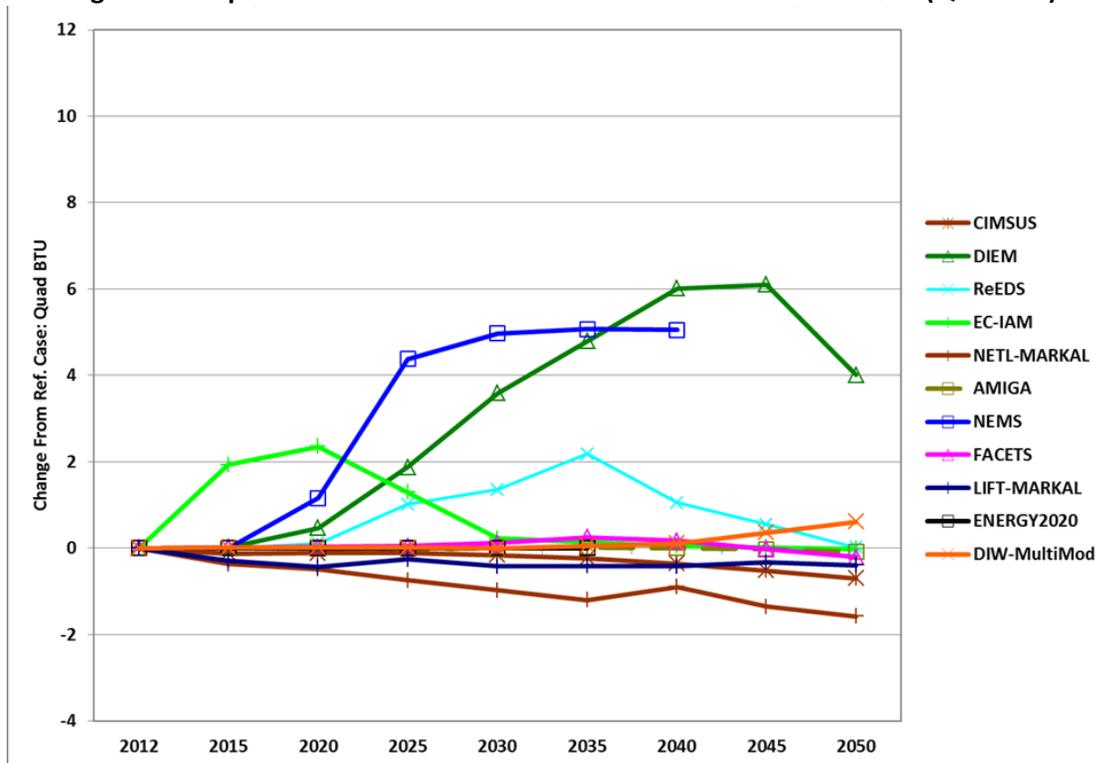


Figure 18. Economy's CO<sub>2</sub> Emissions in Reference Case

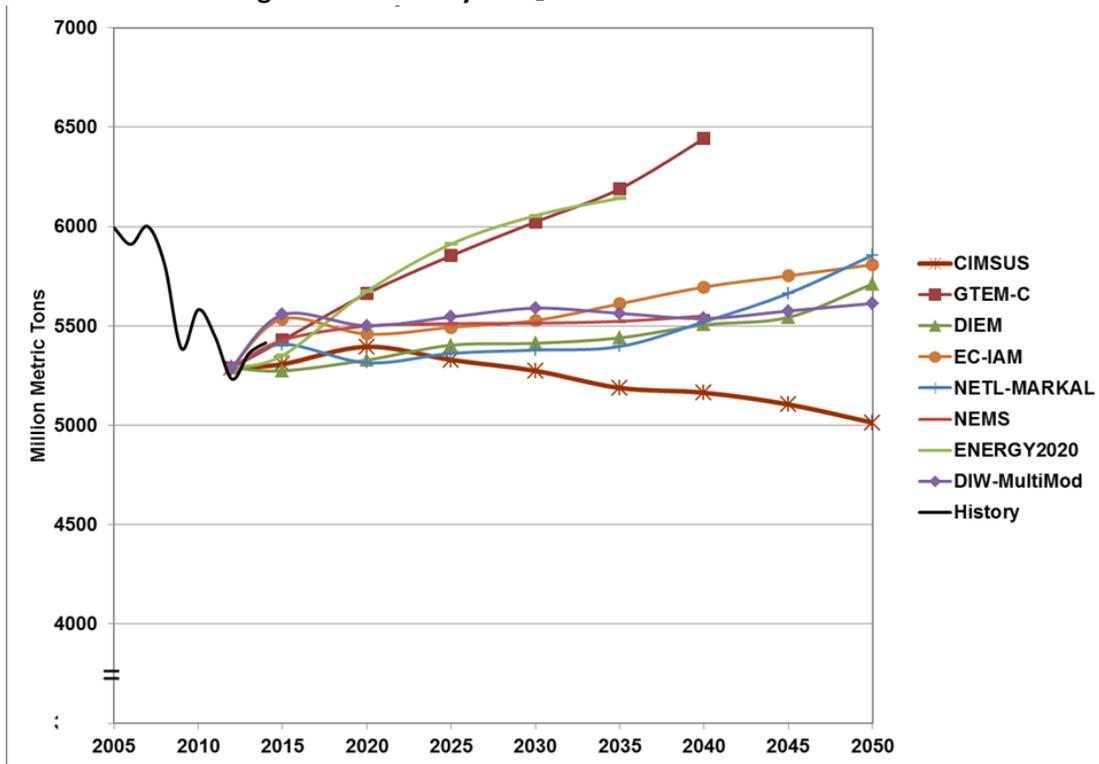
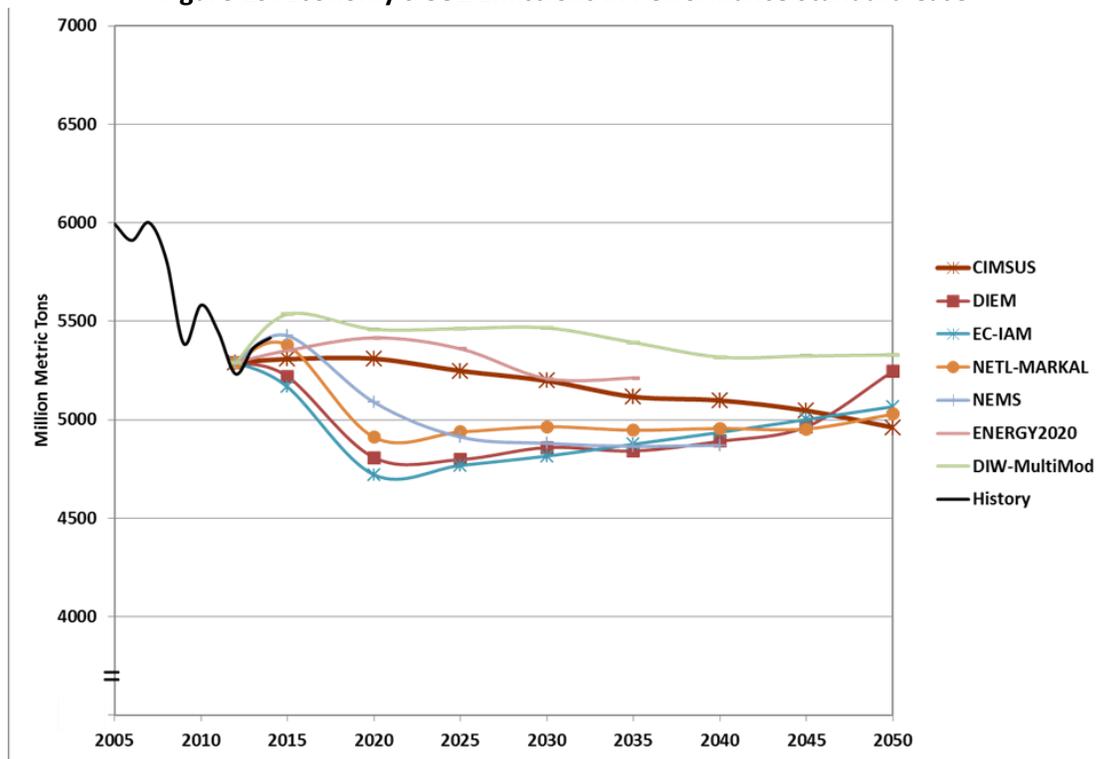
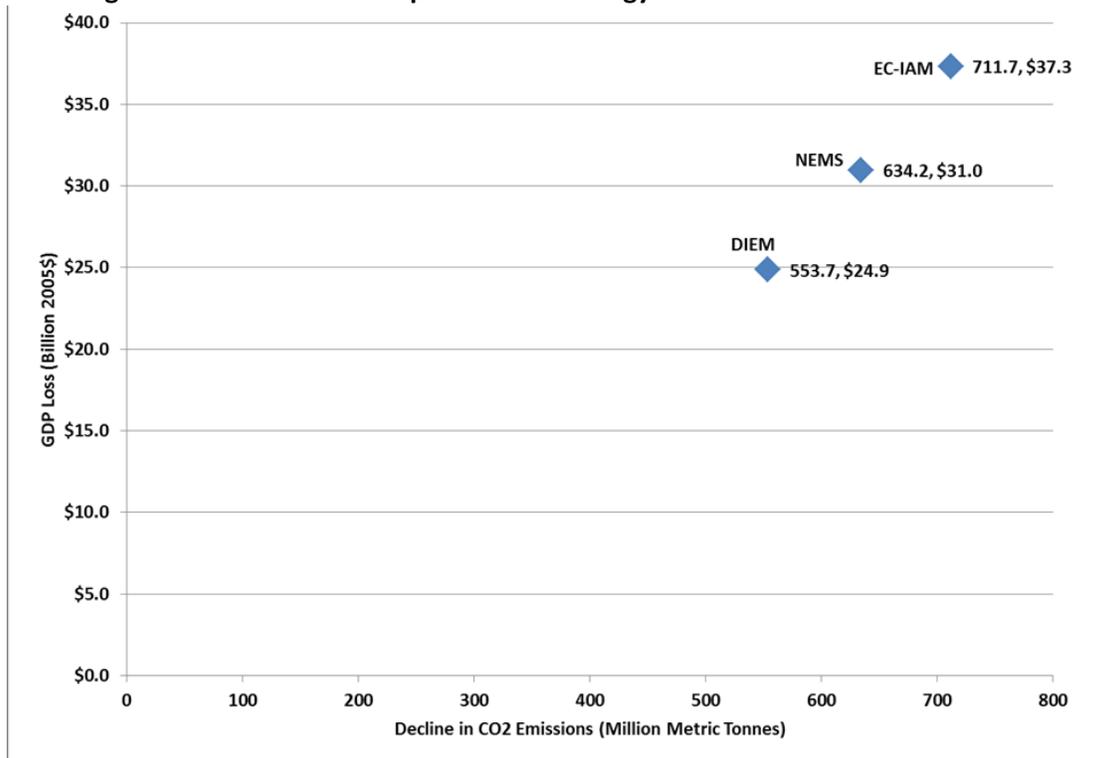


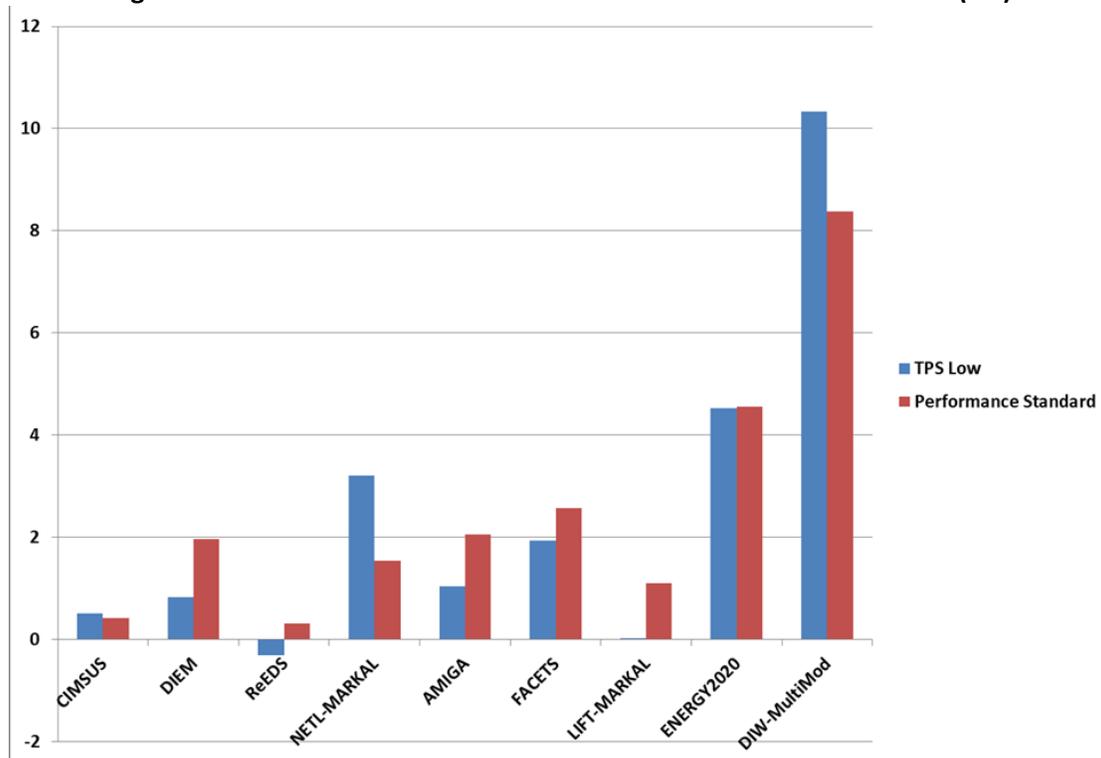
Figure 19. Economy's CO<sub>2</sub> Emissions in Performance Standard Case



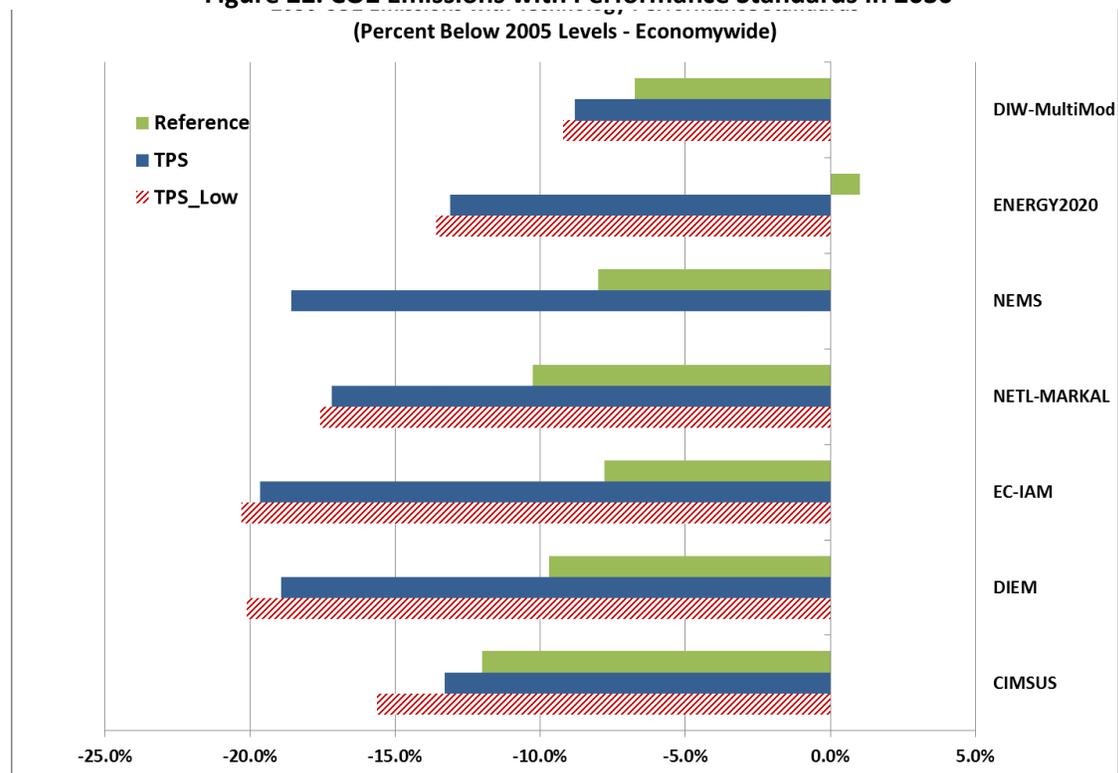
**Figure 20. GDP and CO2 Impacts of Technology Performance Standards in 2030**



**Figure 21. Effect of Performance Standard on Electric Natural Gas Use (Tcf)**



**Figure 22. CO2 Emissions with Performance Standards in 2030**  
(Percent Below 2005 Levels - Economywide)



## Summary Comments

This study coordinated the efforts of 16 different modeling teams to understand the pending transition in North American natural gas markets. Drawing upon the results from these models, the working group identified the major impacts from more available and less expensive shale gas resources. The study also evaluated the wide range of possible U.S. natural gas export levels and the potential for competing use by electric generators if they need to push towards cleaner power, particularly in the early years after 2020.

Immense uncertainty still surrounds the quantification of the nation's resource base: how much is available and at what costs. Prices, production, consumption and exports will be very different depending upon what future geologic research finds. But the study also demonstrates that future trends in energy demand will also play a critical role in this transition. Our knowledge about the substitutability between

fuels in both the power and direct end-use sectors is still evolving.

Evaluating the country's future natural gas trade opportunities requires more elaborate modeling systems that must move in several directions. It is particularly difficult to assess future U.S. natural gas exports without an analysis that incorporates sufficient detail on competing natural gas sources around the world and the demand centers that they service. Moreover, substitution between natural gas and coal as well as other fuels in Asian and European countries has a direct bearing on how well U.S. natural gas exports will compete in world energy markets.

If exporting the hydraulic fracturing technology (with horizontal drilling) is cheaper than exporting physical natural gas volumes across the Atlantic or Pacific oceans, this development may have major global consequences. Chinese shale resources appear vast, but this technology transfer will not happen quickly. Entrepreneurs must find the right rock formations, institutions and political climate for knowledge spillovers to be economic.

As with many new energy technologies, hydraulic fracturing and the rise of shale gas as an energy option raises important environmental concerns. Hydraulic fracturing has been criticized for its water requirements as well as for polluting water and emitting more greenhouse gas emissions from fugitive methane. Further study is also needed to explore whether this development leads to detrimental health impacts and causes earthquakes. Many models in this study are being used for evaluating the tradeoffs between lower-cost natural gas resources and some of these environmental risks. During the course of this study, participants have prepared a series of reports and papers that discuss the possible environmental challenges due to the extraction of shale gas. Many of these papers will be included in a special issue of the journal, *Energy Economics*, which will be available early next year.

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## APPENDIX: EMF 31 SCENARIO DESIGN

### Scenarios for US and Global Models

This study design describes the assumptions for scenarios in the most recent round of EMF 31. U.S. and North American models are asked to simulate the first five cases. Global models are asked to simulate case #1 (Reference), case #2 (High US Shale Resources), and the last four cases (High International Demand, High International Demand with High US Shale Resources, Oil-Indexed Pricing, and Russian Supplies). Modelers are welcome to simulate other cases at their discretion.

Generally, do not override model results for endogenous variables or where you have strong priors. We are testing the model how you use it. Please document any major changes from these assumptions if you decide to override these guidelines.

### Case #1: EMF Reference or Baseline (Reference)

The EMF 31 Reference or Baseline scenario is patterned after the Annual Energy Outlook 2014 Reference case that is available from the US Energy Information Administration at <http://www.eia.gov/oiaf/aeo/tablebrowser/>. Modelers should consider using the AEO 2014 projections for world oil prices, U.S. economic growth and population trends, and current energy and environmental regulatory policies in place at this time. The one exception will be regulations covering the electric power sector where noted below.

The case should incorporate the following assumptions for the power sector:

- 1) Calibrate to AEO 2014 power plant costs and fuel supply curves if you do not use your own estimates. Power plant cost assumptions for AEO2014, which are very similar to those for AEO2013, can be accessed at [http://www.eia.gov/forecasts/aeo/assumptions/pdf/table8\\_2\\_2014er.pdf](http://www.eia.gov/forecasts/aeo/assumptions/pdf/table8_2_2014er.pdf).

- 2) Following the AEO reference case, include CAIR and MATS, but not the non-air new EPA regulations (coal combustion residues, CWA

Section 316(b)). Models that represent the retrofit/retire decision at a fine level of detail are requested to report gigawatts (GW) of retirements for use by more aggregate models. (If you agree to report detailed retirements, please let us know in advance.)

- 3) Include the proposed New Source Performance Standards (NSPS) for CO<sub>2</sub>, which would have the effect of prohibiting new coal without CCS. These rules are not yet implemented.

Unless you are using your own natural gas supply estimates, please calibrate natural gas supply conditions to the price-production paths in AEO 2014 reference case as specified below in [Table A-1](#).

Global models should allow a steady decline in the share of natural gas sales under contracts that are indexed to oil prices in certain Asian economies and completely eliminate their effects by 2025. The Japanese delivered gas price is about \$16 per mmbtu, or 87% of the Brent crude oil price (\$107/B) in Btu terms. In the EMF reference case, modelers should steadily decrease the role played by oil indexation over time by either: (a) reducing the percentage of Japanese gas sales under oil-indexed pricing, or (b) reducing the gas price as a percent of the oil price under oil-indexed contracts. By 2025, please eliminate any oil-indexed contracts that maintain gas prices higher than market-determined prices. This assumption calls for gas-on-gas competition in all regions. If you are uncertain about the speed of this decline, please apply them uniformly each year. Please adjust other Asian contracts (Korea, India and China) and those for Russian exports relative to these assumptions for Japan. Modelers are free to use their discretion in making these assumptions, which are offered as guidelines.

**Table A- 1. AEO2014 Reference Natural Gas Supply Conditions**

	Dry Gas Production (trillion cubic feet)	Henry Hub Spot Price (2012 dollars per thousand cubic feet)
2011	22.5	\$4.07
2012	24.1	\$2.75
2015	24.6	\$3.74
2020	29.1	\$4.38
2025	31.9	\$5.23
2030	34.4	\$6.03
2035	36.1	\$6.92
2040	37.5	\$7.65

### Case #2: High U.S. Shale Resources (High Shale)

The EMF 31 High U.S. Shale Resources scenario represents greater natural gas availability at lower costs than in the reference case. If you have a spatially detailed natural gas supply model that differentiates shale and other unconventional sources from conventional ones, please follow the assumptions for resources and well spacing in the AEO 2014 High Resource case. Otherwise, please incorporate the High U.S. Shale Resource case in one of two ways.

If it is easier to represent greater availability as a cost (or price) reduction, please shift the inflation-adjusted (real) production costs for producing natural gas as shown in Figure A-1. The cost of producing any natural gas production level in each year will be x% lower than in the reference case. The first column of Table A-2 shows the percent cost reduction. These cost reductions approximate the effect of high resources on the natural gas wellhead price relative to the reference case in AEO 2014. It is patterned after the deviation between the High

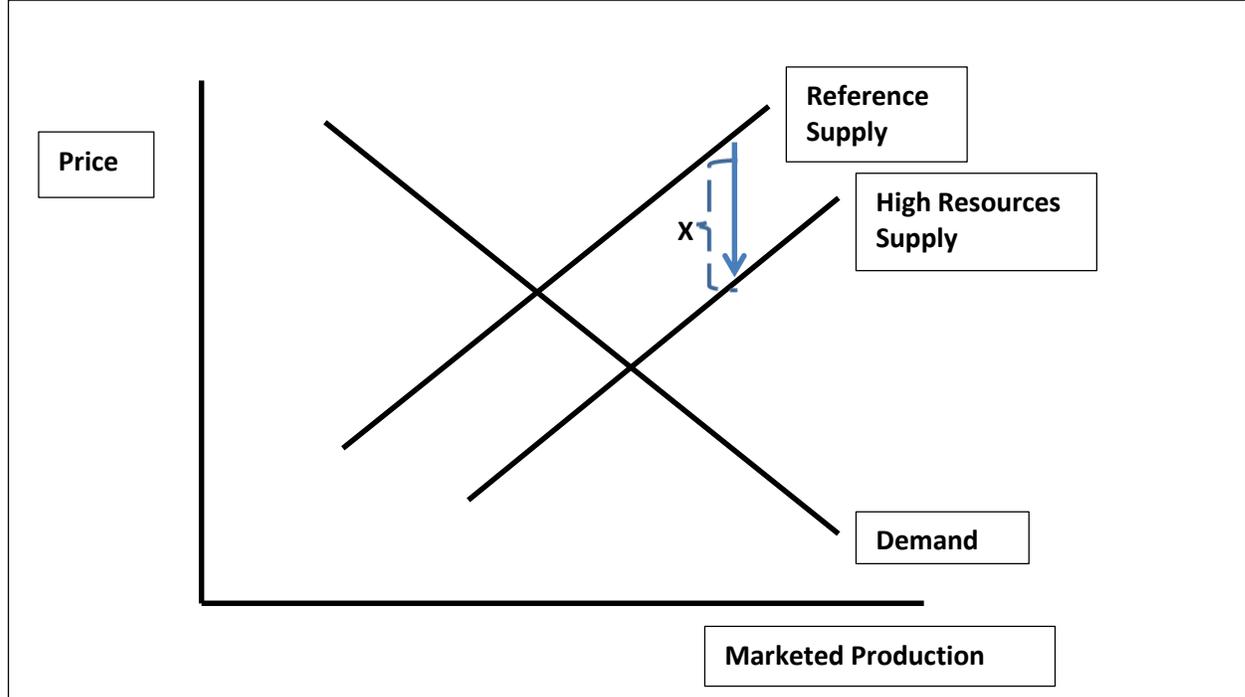
Oil/Gas Resources and Reference cases in the new Annual Energy Outlook 2014 released by the US Energy Information Administration, also available at <http://www.eia.gov/oiaf/aeo/tablebrowser/>.

If it is easier to represent greater availability as a production increase in your model, please shift the U.S. resource or supply amounts at all prices by the percentages shown in the third column of Table A-2. It is important that you shift the supply curve in either a price or a quantity direction, but not both.

Do not shift the supply curves for domestic oil in this EMF scenario. Modelers are invited to report a modeler choice case that allows shifts in both domestic oil and natural gas production curves. Allow more abundant natural gas resources to dampen world oil prices only if your model traces this effect endogenously.

For global models, please keep international supply and demand conditions (price-quantity curves) outside the United States unchanged.

Figure A-1. Incorporating Cost Reduction in High Resource Case



### Case #3: Low U.S. Shale Resources (Low Shale)

The EMF 31 Low Shale Resources scenario represents less natural gas availability at higher costs than in the reference case. If you have a spatially detailed natural gas supply model that differentiates shale and other unconventional sources from conventional ones, please follow the assumptions for resources and well spacing in the AEO 2014 Low Resource case. Otherwise, please incorporate the Low Shale Resource case in one of two ways.

If it is easier to represent less availability as a cost (or price) increase, please shift the inflation-adjusted (real) production costs for producing natural gas as shown in Figure A-2. The cost of producing any natural gas production level in

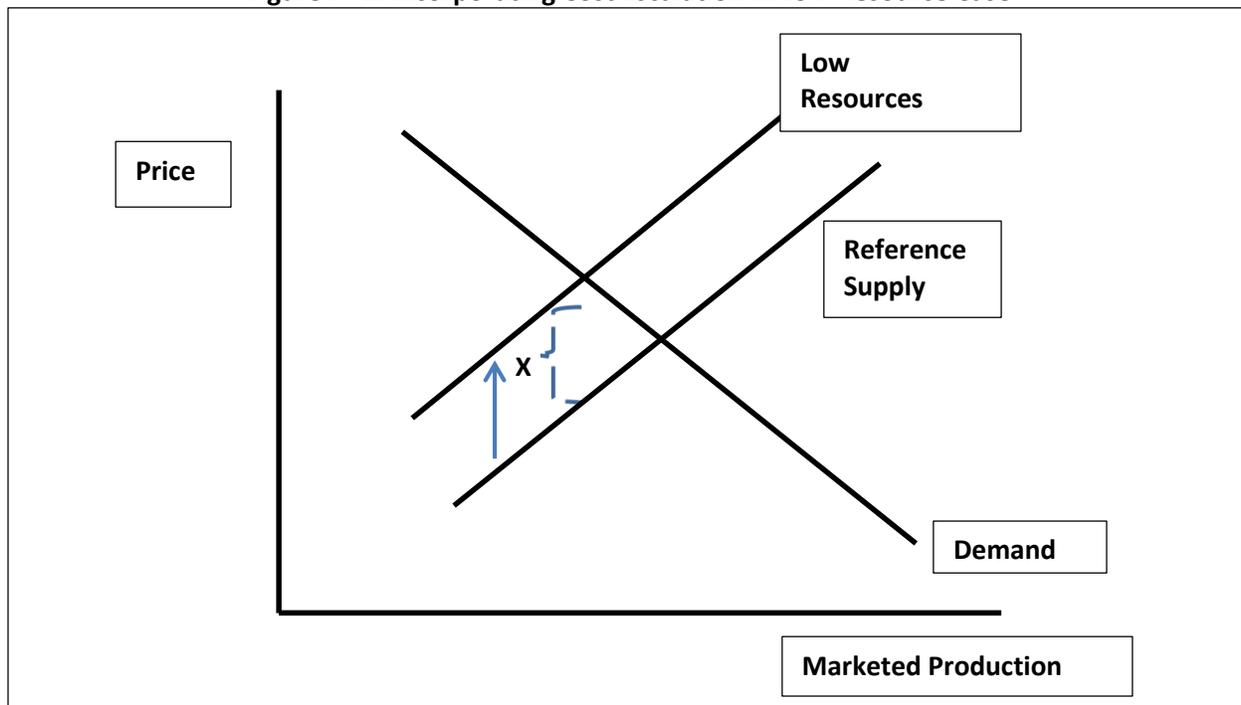
each year will be  $x\%$  higher than in the reference case. The second column of Table A-2 shows the percent cost reduction. These cost reductions approximate the effect of low resources on the natural gas wellhead price relative to the reference case in AEO 2014. It is patterned after the deviation between the High Oil/Gas Resources and Reference cases in the Annual Energy Outlook 2014 released by the US Energy Information Administration, also available at <http://www.eia.gov/oiaf/aeo/table-browser/>.

If it is easier to represent less availability as a production decrease in your model, please shift the U.S. resource or supply amounts at all prices by the percentages shown in the fourth column of Table A-2. It is important that you shift the supply curve in either a price or a quantity direction, but not both.

**Table A-2. Resource Shifts in Scenarios #2 and #3**

	<u>Price/Cost Shifts (%)</u>		<u>Quantity Shifts (%)</u>	
	High Shale	Low Shale	High Shale	Low Shale
2015	-9%	6%	3%	-2%
2020	-10%	21%	8%	-8%
2025	-12%	31%	13%	-11%
2030	-30%	35%	13%	-16%
2035	-33%	32%	15%	-20%
2040	-40%	38%	21%	-25%

**Figure A- 2. Incorporating Cost Escalation in Low Resource Case**



Do not shift the supply curves for domestic oil in this EMF scenario. Modelers are invited to report a modeler choice case that allows shifts in both domestic oil and natural gas production curves. Allow changes in natural gas resources to influence world oil prices only if your model traces this effect endogenously.

For global models, please keep international supply and demand conditions (price-quantity curves) outside the United States unchanged.

### Case #4: Technology Performance Standard

The purpose of this case is to evaluate how changes in the regulation of the power sector's carbon dioxide emissions will impact natural gas markets. This case is patterned after the recent EPA Clean Power Plan, although not all rules have been completely specified and considerable latitude exists in how each individual state will implement the plan within its borders. Modelers are requested to simulate a technology

performance standard (TPS) for the electric power sector. The tradable emissions rate Performance Standard sets a fleet average CO<sub>2</sub> emissions rate standard (tons/MWh) across all existing and new fossil generators and allows trading of credits to achieve the standard. A generator earns (owes) a credit on each MWh of generation for each ton/MWh that its emissions rate is below (above) the standard. A TPS was selected for this case because of its relevance to ongoing EPA deliberations on an upcoming performance standard for existing plants, and because it will highlight coal-gas tradeoffs under a power sector carbon policy.

The TPS can be thought in three equivalent ways:

- a credit trading system in which generators are allocated credits based on the standard emissions rate and must hold enough credits to cover their actual emissions rate;
- a cap-and-trade policy that allocates emissions allowances to all generators on the basis of current period electricity production;
- a simultaneous tax on CO<sub>2</sub> emissions at the current credit trading price and subsidy based on the standard emissions rate.

Details of policy implementation are as follows:

- The policy covers all new and existing powerplants beginning in the year 2020.
- The emissions rate target would have to be met on average across all of these plants, not by each individual unit.
- The emissions rate target equals the national average of the state rates under EPA's draft Clean Power Plan as specified below.
- The national target CO-2 emissions rate for these plants should be set equal to 1076 pounds CO-2 per megawatt-hour for each year between 2020 and 2029.
- The national target CO-2 emissions rate for these plants should be capped at 1001 pounds CO-2 per megawatt-hour in 2030 (30% below the average emissions rate for carbon-generating plants in 2005).
- After 2030, the case assumes that new policies will be implemented such that the national target CO-2 emissions rate for these plants should decrease by 1% per year to reach a level of 819 pounds per megawatt-hour by 2050.
- Banking of credits for use in future periods is allowed by this policy.
- Please include the following sources in the numerator and denominator of the emissions intensity rate (pounds CO-2 per MWh generation):

Source	Pounds CO-2 Emissions (Numerator)	MW-Hours Generation (Denominator)
Coal	Include	Include
Natural Gas	Include	Include
Oil	Include	Include
Nuclear		Include 6% of existing plants (6% ~ 46,000 thousand MWh) + all new plants. The draft EPA Clean Power Plan lists nuclear plants under construction and existing plants "At Risk" as being 88,597 (Thousand MWh) nationally.
Hydroelectricity		Exclude
Non-Hydro Renewables		Include
Energy Efficiency		Exclude

### Case #5: Technology Performance Standard with Low Shale Resources (TPS Low)

The purpose of this scenario is to understand how the technology performance standard shapes energy markets when U.S. natural gas availability is more limited and more expensive than in the reference case. Please combine the assumptions made in the technology performance standard case with those in the low shale resource case.

### Case #6: High International Demand (High Demand)

This case will expand the Asian demand for natural gas by approximately 20% in 2040. These increments in preference consumption should be added to reference consumption levels at the reference price levels, i.e., they are shifts in the foreign demand curve as a result of policies or technological change (as opposed to a direct price change). Consumption levels after the model has achieved market equilibrium will most likely be lower than the preference levels specified in these scenarios as prices are likely to rise. Modelers may implement this case in one of two ways depending upon the model's structure.

If you have country, sector and technology disaggregation, assume the following:

- Annual Chinese coal use for electric generation grows by 1% per year less than in the reference case through 2050 due to exogenous policies.
- Annual Korean nuclear use grows by 1% per year less than in the reference case through 2050 due to exogenous policies.

- Please do not impose any additional regulatory restrictions on other fuels (like renewables) that do not already exist in the reference case.
- Please adjust these assumptions (and document them) if you think that your expansions in demand (preferred consumption) are substantially above or below a 20% Asian shock in 2040.

If you do not have country, sector and technology disaggregation, please expand demand (preferred consumption) by shifting the Asian demand for natural gas directly. Please shift preferred consumption gradually to 20% above reference levels by 2040, using the timing suggested in [Table A-3](#) where possible. This trajectory is suggested but not required.

For reference, Asian gas demand is 46 Tcf and world gas demand outside the USA is 155 Tcf in 2040 from the IEO 2013 reference case. Based upon these estimates, an Asian shock of 20% translates to about 9 Tcf. This shock translates to about 6% of the world gas demand outside the USA in 2040.

### Case #7: High International Demand with High Resource Supply (High Demand High)

The purpose of this scenario is to evaluate the high international demand conditions when US natural gas is more abundant and less costly than in the reference case. Please combine the assumptions made in the high international demand case with those in the high shale resource case.

**Table A-3. Percent Deviation for High Asian Demand Scenario**

	2015	2020	2025	2030	2035	2040
Demand Shock	3%	9%	11%	14%	17%	20%

### Case #8: Oil-Indexed Pricing

This case evaluates the competitiveness of US natural gas exports when Japan and other relevant regions reduce their share of oil-indexed contracts less rapidly than in the reference case. Please reduce the contract decline process by a factor of two, such that all oil-indexed contracts are eliminated by 2035 rather than by 2025 in the reference case. Modelers are invited to submit other modeler choice scenarios applying different assumptions. Please document any key assumptions if you submit these additional alternative cases. All other assumptions should remain the same as in the reference case.

### Case #9: Russian Supplies

This case evaluates the opportunities for U.S. natural gas exports when some Russian natural gas supplies are more costly or constrained by limited investment. Modelers are asked to represent the following conditions:

- resources in the Yamal Peninsula and Kara Sea become more costly, effectively rendering it unattractive to foreign capital and removing it from the mix of Russian supplies that could economically reach the market, and
- the available capacity of pipelines through Ukraine is phased out to reflect a preference of European consumers to seek alternative routes, including other commercial avenues for Russian gas to reach Europe.

This scenario may require further standardization once modelers begin to simulate these

conditions. Please contact EMF staff if you would like further advice on incorporating these assumptions.

### Measured Costs

Please indicate whether you can report the costs (benefits) of an alternative case (policy or supply conditions) relative to the reference case. Please describe how costs are computed and what they represent. For example, a model may estimate costs in one of several ways:

- the social welfare costs attributable to changes in consumer and producer surpluses;
- the loss in aggregate economic consumption of all goods and services;
- the additional costs associated with the power sector's generation costs;
- changes in consumer energy expenditures;
- changes in gross domestic product; or
- an alternative metric that is not included in the above list.

### Output Variables

Modelers are requested to submit results by March 31 in order that EMF staff can review results and develop preliminary conclusions for the May 7-8 meeting. Please report results from each scenario covering the 2015-2050 period in a worksheet provided by EMF. The variables listed below are those that were reported in the second round. Please report any variables that you can from the following list:

Sector	Variable	Units	Additional Notes	2012(EIA)
Consumption	Liquids	Quad BTU	See Table AEO, A2. Includes Liquefied Petroleum Gases and Other, E85, Motor Gasoline, Jet Fuel, Kerosene, Distillate Fuel Oil, Residual Fuel Oil, Petrochemical Feedstocks, and Other Petroleum.	35.87
Consumption	Natural Gas	Quad BTU	Includes Pipeline Fuel and Lease and Plant Fuel.	26.20
Consumption	Coal	Quad BTU		17.34
Consumption	Nuclear	Quad BTU		8.05
Consumption	Renew ables	Quad BTU	Includes hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources.	6.65
Consumption	Total Primary	Quad BTU	Also includes Biofuels Heat and Coproducts, Renewable Energy, Liquid Hydrogen, Non-biogenic Municipal Waste, and Electricity Imports	95.02
Industrial	Liquids	Quad BTU	See Table AEO, A2. Includes Liquefied Petroleum Gases and Other, Motor Gasoline, Distillate Fuel Oil, Residual Fuel Oil, Petrochemical Feedstocks, and Other Petroleum.	8.06
Industrial	Natural Gas	Quad BTU	Excludes Pipeline Fuel and Lease and Plant Fuel.	7.29
Industrial	Coal	Quad BTU		1.48
Industrial	Renew ables	Quad BTU		1.48
Industrial	Electricity	Quad BTU		3.35
Industrial	Total Delivered	Quad BTU		23.63
Electricity	Natural Gas	Quad BTU		9.46
Electricity	Coal	Quad BTU		15.82
Electricity	Nuclear	Quad BTU		8.05
Electricity	Renew ables	Quad BTU		4.59
Electricity	Total	Quad BTU		38.53
Electricity	Total Sales	BKw H	Retail Sales to Ultimate Customers	3,694.65
Residential	Natural Gas	Tcf	Divide Quad BTU by 1.022	4.17
Commercial	Natural Gas	Tcf	Divide Quad BTU by 1.022	2.90
Industry	Natural Gas	Tcf	Divide Quad BTU by 1.022. Excludes Pipeline Fuel and Lease and Plant Fuel.	7.14
Electric	Natural Gas	Tcf	Divide Quad BTU by 1.022	9.25
Transportation	Natural Gas	Tcf	Divide Quad BTU by 1.022. Gas used in motor vehicles, trains, and ships.	0.04
Total Consumption	Natural Gas	Tcf	Divide Quad BTU by 1.022. Includes Pipeline Fuel and Lease and Plant Fuel.	25.64
Production	Natural Gas	Tcf	Marketed production (wet) minus extraction losses.	24.06
LNG Net Exports	Natural Gas	Tcf	Exports minus Imports	-0.15
Mexico Net Exports	Natural Gas	Tcf	Exports minus Imports	0.62
Canada Net Exports	Natural Gas	Tcf	Exports minus Imports	-1.99
Total Net Exports	Natural Gas	Tcf	Exports minus Imports	-1.51
Price	Henry Hub	2012\$/mmbtu	Excludes any carbon fees	2.75
Price	Brent Oil	2012\$/barrel	Excludes any carbon fees	111.65
Price	Coal Minemouth	2012\$/ton	Excludes any carbon fees	39.94
Price	Electricity	2012	All sectors; excl. carbon fees	9.84
Economy	Real GDP	Billion 2005\$		13,593.20
Economy	Economic Cost	Billion 2005\$	Costs w/r to Reference	0.00
Economy	Carbon Dioxide Emissions	Million Metric Tons	Total Energy-Related (all sectors)	5,289.86
Electricity	Sulfur Dioxide Emissions	Million Short Tons	Electricity only	3.34
Electricity	Nitrogen Oxide Emissions	Million Short Tons	Electricity only	1.68