EMF 31 Scenario Design (February 2015)

Summary and Important Changes from the Previous Round

- The high-demand case has been specified as a high Asian demand case (revised, February 2015).
- The EMF Reference case continues to be based upon the AEO 2014 Reference case.
- The EMF High Shale Resources case can be implemented as either a reduction in costs (prices) or an expansion in availability, based upon the AEO High Shale case.
- The EMF Low Shale Resources case replaces the Escalated Cost case from the previous study design. It can be implemented as either an increase in costs (prices) or more limited availability, based upon the AEO Low Shale case.
- The Technology Performance Standard specifications now include more explicit directions for representing which generation is included in the denominator of the target.
- The Technology Performance Standard case should also be simulated with the Low (U.S.) Shale Resource assumptions.
- The High International Demand case should also be simulated with the High (U.S.) Shale Resource assumptions.
- There are no changes in the variables to be reported on the EMF template.

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.

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 CO2, 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 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 1. AEO2014 Reference Natural Gas Supply Conditions

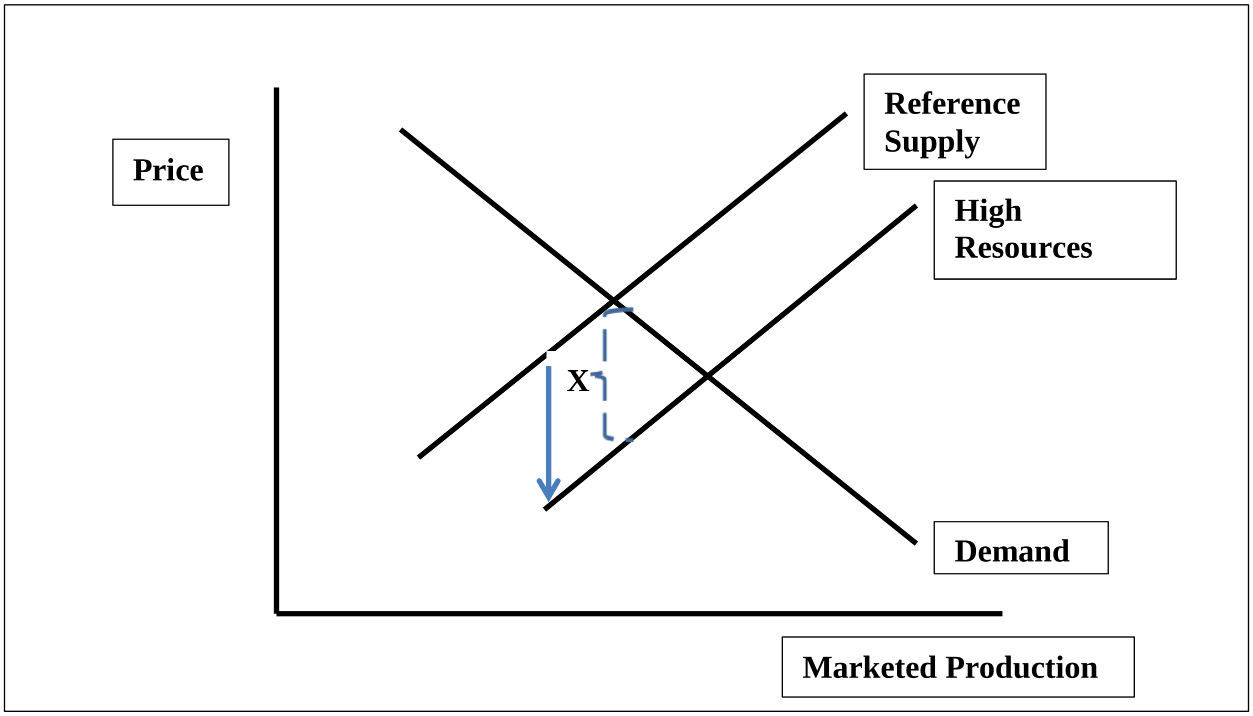
	Dry Gas Production (trillion cubic feet)	Henry Hub Spot Price (2012 dollars per thousand cubic feet)
2011	22.5	$4.07
2012	24.1	$2.75
2015	24.6	$3.74
2020	29.1	$4.38
2025	31.9	$5.23
2030	34.4	$6.03
2035	36.1	$6.92
2040	37.5	$7.65

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 1. The cost of producing any natural gas production level in each year will be x percent lower than in the reference case. The first column of Table 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/.

Figure 1. Incorporating Cost Reduction in High Resource Case



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 2. It is important that you shift the supply curve in either a price or a quantity direction, but not both.

Table 2. Resource Shifts in Scenarios #2 and #3

	Price/Cost Shifts (%)		Quantity Shifts (%)	
	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%

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.

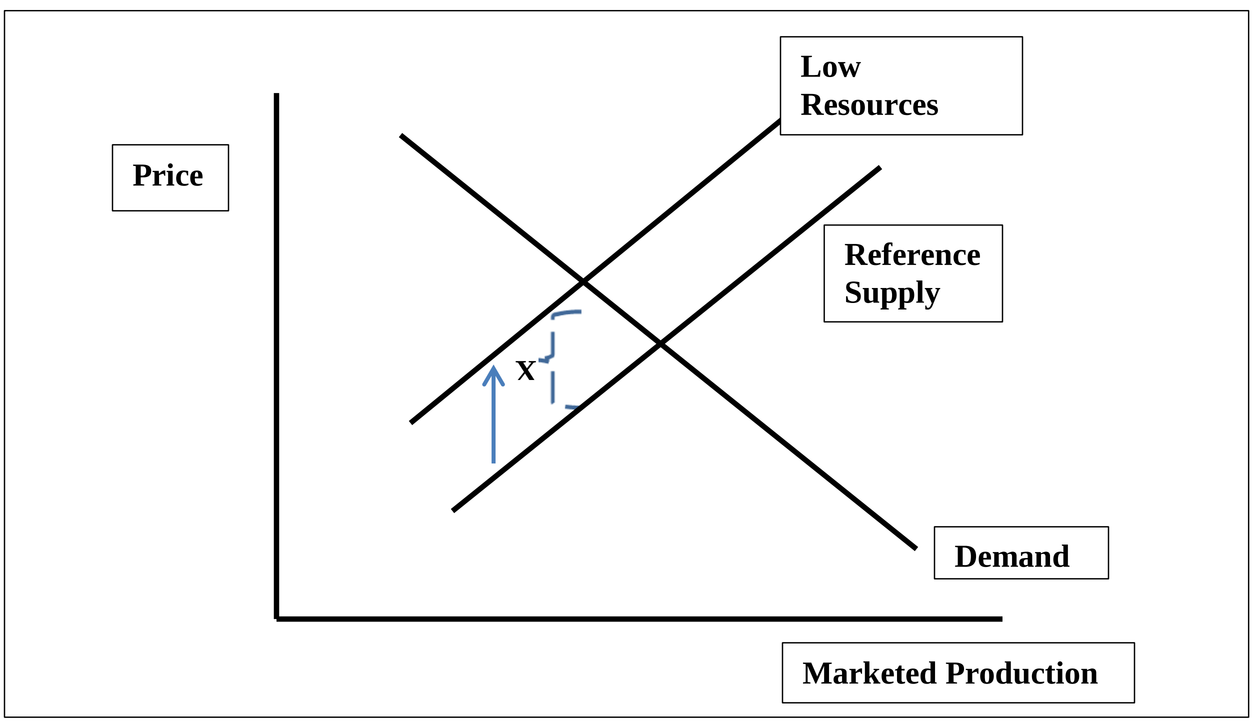
For global models, please keep international supply and demand conditions (price-quantity curves) outside the United States unchanged.

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 2. The cost of producing any natural gas production level in each year will be x percent higher than in the reference case. The second column of Table 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/tablebrowser/.

Figure 2. Incorporating Cost Escalation in High Resource Case



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 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 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_2 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_2 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 percent 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 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.

Table 3. Percent Deviation for High Asian Demand Scenario

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

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.

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:

(1) 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
(2) 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 my 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, w ood and w ood w aste, biogenic municipal w aste, other biomass, w ind, photovoltaic, and solar thermal sources.	6.65
Consumption	Total Primary	Quad BTU	Also includes Biofuels Heat and Coproducts, Renew able 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 Consumptio	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 (w et) minus extraction losses.	24.06
LNG Net Exports	Natural Gas	Tcf	Exports minus Imports	(0.15)
Mexico Net Expo	Natural Gas	Tcf	Exports minus Imports	0.62
Canada Net Expo	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$/ton	Excludes any carbon fees	39.94
Price	Electricity	2012 cents/kw h	All sectors; excl. carbon fees	9.84
Economy	Real GDP	Billion 2005$		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