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Characterizing the Emissions Implications of Future Natural Gas Production and Use in the U.S. and Rocky Mountain Region: A Scenario-based Energy System Modeling Approach

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CHARACTERIZING THE EMISSION IMPLICATIONS OF FUTURE NATURAL GAS PRODUCTION AND USE IN THE U.S. AND ROCKY MOUNTAIN REGION: A SCENARIO-BASED ENERGY SYSTEM MODELING APPROACH

by

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The recent increase in U.S. natural gas production made possible through advancements in extraction techniques including hydraulic fracturing has transformed the U.S. energy supply landscape while raising questions regarding the balance of environmental impacts associated with natural gas production and use. Impact areas at issue include emissions of methane and criteria pollutants from natural gas production, alongside changes in emissions from increased use of natural gas in place of coal for electricity generation. In the Rocky Mountain region, these impact areas have been subject to additional scrutiny due to the high level of regional oil and gas production activity and concerns over its links to air quality. Here, the MARKAL (MArket ALlocation) least-cost energy system optimization model in conjunction with the EPA-MARKAL nine-region database has been used to characterize future regional and national emissions of CO_2, CH_4, VOC, and NO_x attributed to natural gas production and use in several sectors of the economy. The analysis is informed by comparing and contrasting a base case, business-as-usual scenario with scenarios featuring variations in future natural gas supply characteristics, constraints affecting the electricity generation mix, carbon emission reduction strategies and increased demand for natural gas in the transportation sector. Emission trends and their associated sensitivities are identified and contrasted between the Rocky Mountain region and the U.S. as a whole. The modeling results of this study illustrate the resilience of the short term greenhouse gas emission benefits associated with fuel switching from coal to gas in the electric sector, but also call attention to the long term implications of increasing natural gas production and use for emissions of methane and VOCs, especially in the Rocky Mountain region. This analysis can help to inform the broader discussion of the potential environmental impacts of future natural gas production and use by illustrating links between relevant economic and environmental variables.

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I. Introduction/Background

In the past decade, natural gas (NG) has risen to the forefront of the United States energy supply landscape as a cheap, domestically abundant, and comparatively clean fossil fuel suitable for meeting demand for energy services in multiple economic sectors. The combined use of hydraulic fracturing and horizontal drilling to extract NG from shale formations has facilitated this rise by allowing large reserves of NG found underneath impermeable layers of rock to be economically produced (EIA 2012). Shale gas has been the primary driver of growth in the NG industry: U.S. proven reserves of shale gas more than quadrupled from 23.3 trillion cubic feet (Tcf) to 132 Tcf between 2007 and 2011 according to the U.S. Energy Information Administration (EIA), and growth in production from shale reserves resulted in a 35% increase in overall NG production from 2005-2013 (EIA 2014). This increased availability of affordable NG has resulted in greater NG use in the electricity sector: electricity generation from NG increased 46% from 2005-2013 while generation from coal and petroleum fell by 21% and 78%, respectively (EIA 2014). Additionally, expansion of NG production and use is projected to continue into the future: in its latest Annual Energy Outlook (AEO), the EIA adjusted its NG production forecast upward to account for continued growth of shale gas production, while also projecting that electricity production from NG will surpass that from coal in 2035 and predicting that the U.S. will become a net exporter of NG within a decade (EIA 2014). Compressed NG (CNG) and liquefied NG (LNG) will also likely play a significant role in future transportation sector fuel supply, providing an opportunity to reduce vehicle greenhouse gas (GHG) emissions and facilitate lower reliance on petroleum imports (MIT 2011, Venkatesh et al. 2011).

The Rocky Mountain region contains many NG basins that account for a significant portion of past and projected growth in shale gas production, including the Denver-Julesberg, Piceance, Uinta, and Powder River basins. Of the dry NG produced in the U.S. from 2005-2012, 18% came from Colorado, Utah and Wyoming (EIA 2013).

Concerns about the environmental impacts associated with expanded production and use of NG have accompanied the shale gas boom and continue to temper the optimism surrounding the fuel's future benefits. NG has widely been touted as a "bridge fuel" between coal and renewables for electricity generation, as its combustion produces about half the amount of carbon dioxide (CO_2) of that of coal (MIT 2011). Indeed, some of the apparent recent reduction in U.S. carbon emissions may be attributed to fuel switching in the electric sector from coal to NG (Broderick & Anderson 2012). However, the net climate change impact of increased NG production and use in the future is less clear, due to uncertainty surrounding the magnitude of methane released to the atmosphere during NG extraction, processing, transmission and distribution (e.g. Bradbury et al. 2013, Alvarez et al. 2012, Brandt et al. 2014) as well as NG's potential to slow penetration of renewable technologies into the U.S. electricity mix. In addition to its potential climate change impacts, activities involved in NG and oil production may contribute to adverse effects on air quality in areas with high levels of production activity, due to emission of harmful pollutants including volatile organic compounds (VOC), nitrogen oxides (NO_x), particulate matter ($PM_{2.5}$ & PM_{10}), and sulfur oxides (SO_x) as well as other hazardous air pollutants (Litovitz et al. 2013). In the Rocky Mountain region, the influence of oil and NG operations on the presence of VOCs and NO_x in the atmosphere has been demonstrated by direct measurement studies (e.g. Pétron et al. 2012, Gilman et al. 2013, Utah DEQ 2013) and episodes of high tropospheric ozone formation have been linked to emissions of ozone precursors from oil & NG extraction activities (Rodriguez et al. 2009, Schnell et al. 2009).

Questions and uncertainties surrounding the implications of future NG production and use in the energy system, particularly in the electric power generation and transportation sectors, are challenging for policymakers and other stakeholders attempting to reconcile environmental and economic considerations in assessing the role that this important fuel will play in the energy supply landscape on the national scale and in the Rocky Mountain region specifically. The implications of fuel switching from coal to NG in the electric sector for regional and national scale GHG emissions must incorporate estimates of methane leakage and be balanced against prospects for sustainably meeting additional electricity demand in the long term. Additionally, any large scale or long term climate benefits of future NG use as well as improvements in regional air quality as a result of less coal burning for electricity may be accompanied by problematic regional air quality impacts as a result of the aforementioned pollutant emissions associated with NG production.

Scenario-based modeling approaches prove helpful in addressing these tradeoffs because they allow for isolation and analysis of the effects of potential policies and/or implications of future trends in NG production and use. This study features a scenario-based assessment of the emissions implications of future NG production and use in the Rocky Mountain region as well as in the U.S. as a whole, using the Market Allocation (MARKAL) energy system optimization model in conjunction with the Environmental Protection Agency (EPA)'s U.S. Nine-region database (EPAUS9r) (Loughlin et al. 2011, EPA 2013). The study objectives are to characterize future GHG, VOC, and NO_x emission trends in the Rocky Mountain region as well as trends in NG production and the mix of electricity supply technologies, explain the connections between these trends using energy system analysis based on a detailed least-cost planning model, and compare and contrast the regional modeling results to corresponding results for the U.S. as a whole. MARKAL has proven to be a useful tool for these types of analyses, as shown in MIT 2011 and Akhtar et al. 2013. Past comprehensive modeling studies, including those by EIA and teams at the National Renewable Energy Laboratory (NREL), have used scenario-based approaches to project trends in regional and national electricity generation and GHG emissions out to 2050 under various assumptions characterizing the energy system including some specifically designed to assess the future role of NG use (EIA 2013, NREL 2012, JISEA 2012). Additionally, scenario development focused on characterizing future NG production and use under the influence of various policy, resource supply, and market factors has also been performed, with a focus on GHG emissions from NG extraction (Bradbury et al. 2013).

This study is distinguished from previous work in that it utilizes the EPAUS9r database, which provides detailed emissions data associated with an exhaustive set of processes that includes inter-regional trade of fuels and other energy carriers, energy storage, fossil fuel extraction, and delivery of energy services to end uses along with many other processes characterizing the U.S. energy system (EPA 2013). The database assumptions also incorporate a range of currently applicable environmental regulations that affect future energy supply characteristics in each economic sector. This study goes beyond the standard EPA US9r database in incorporating recent estimates, some unique to the Rocky Mountain region, for NG production-related GHG and criteria pollutant emissions in order to better inform the analysis of future emissions trends and their sensitivities. The detail and quality of the modeling assumptions used in this study, which leverage the expertise of the EPA on climate change and air quality issues as well as NREL on cost and performance estimates for renewable electricity generating technologies, allow for a novel approach to characterizing future NG production and use and their emissions impacts on the regional and national scales

II. Methods

The U.S. EPA implementation of the MARKAL energy systems optimization model is used here to compare future scenarios for NG production and use in the context of the overall U.S. energy system, including energy resource extraction, processing and distribution, electricity production, and electricity or fuel use in the transportation, industrial, commercial, and residential sectors. MARKAL finds the least cost means to satisfy future end use demand, under specified constraints including limits on fuel supplies and on rates of capacity expansion and introduction of new technology. Constraints can also be imposed on emissions or use of specified types of technology. Demand is specified in terms of services, rather than energy, allowing for adoption of end-use technologies that improve energy efficiency. The MARKAL model is run with the EPA's 9-region database, which specifies fuel supply characteristics and energy conversion technology performance and costs from 2005 – 2055, in five-year time steps. The database is spatially resolved into the nine U.S. Census regions. Energy resources are transported across regions through modeled distribution routes, including pipelines and transmissions lines, for which capacity can be expanded over time, subject to constraints on rates of expansion. The version of the database that provided the starting point for this study was released in November 2012 and uses assumptions from the U.S. Energy Information Administration's 2012 Annual Energy Outlook (EIA 2012). The model uses a system-wide discount rate of 5%, supplemented by technology specific "hurdle" rates that reflect additional barriers to new investment.

A unique strength of the EPA MARKAL model is its inclusion of energy-related emissions of criteria pollutants and greenhouse gases, including emissions associated with resource extraction and upstream processing as well as energy conversion processes. The model includes direct emissions control options (e.g., flue gas desulfurization) for electricity generating units and some sources in the industrial sector. Emissions in other end-use sectors, including transportation, are determined by choice of technology. The current version of the model incorporates current emissions limits corresponding to the Clean Air Interstate Rule, light duty fuel economy constraints corresponding to the CAFE standards promulgated in 2012, and state-level renewable portfolio standards in place as of 2013.

While the EPA 9-region database contains inputs that require MARKAL to match real-world conditions in its solutions for the 2005-2010 time frame, the scenario results from 2010 on should not be interpreted as quantitative predictions about the future; rather, these scenarios are useful in characterizing the potential effects that future real-world developments might have. Further details on the EPA MARKAL model are available in the model documentation (Shay et al., 2006; 2008) and from previous research studies that have applied it (Loughlin et al., 2011; Brown et al., 2013; Akhtar et al. 2013).

IIa. Changes to the MARKAL base case assumptions

Several adjustments to assumptions from the 2012 EPAUS9r database were made in this study in order to reflect updated or refined source information and correct a few errors. Changes made to the base case model inputs for this study are detailed as follows, best presented in list format:

- Corrected inaccuracies in the coal supply database with regard to energy and sulfur content of mined coal in different regions: The unaltered coal supply database obtained from EPA contained errors that caused all mined coal regardless of its region of origin to have the same energy and sulfur content. These values were corrected for each region.

- Changed base year used for calculating delivered NG costs from 2008 to 2010: Cost of delivering NG to end-use sectors (residential, commercial, industrial, transportation, electric) is calculated by subtracting wellhead prices from delivered NG costs for 2005 using EIA data. Scaling factors are then applied to produce delivery costs for later years. For this study, the source for delivered NG costs in 2005 was changed from AEO 2010 to AEO 2012.
- Updated state Renewable Portfolio Standards (RPS) to 2013 data: The state RPS assumptions applied to the base case were updated with the latest data available from the Database of State Incentives for Renewables & Efficiency at http://www.dsireusa.org.
- Updated cost and performance data for new electric generating plants: Capital costs, operation and maintenance costs, heat rates, capacity factors, and several other features of new electric generating plants were updated using assumptions from the AEO 2013 (EIA 2013).
- Replaced existing cost inputs for solar photovoltaic and wind: The source used for capital costs and O&M costs related to wind and solar PV technologies was changed from AEO 2012 assumptions to those from Black and Veatch 2012 (Black & Veatch 2012). This change was implemented to reflect more realistic cost assumptions used by NREL in its Renewable Electricity Futures study (NREL 2012).
- Constrained regional geothermal capacity: implemented upper bounds of zero for electricity generated by geothermal plants in regions with no significant geothermal resource: all regions but the Rocky Mountain (R8) and Pacific (R9).

- Adjusted regional wind and solar PV capacity values: see description of Fossil Cap scenario for details.
- Imposed maximum lifetime on existing coal plants: the original MARKAL assumptions for lifetime of existing coal plants, including those from 1950 and earlier, allowed the model to renew the old plants for a fraction of the cost of building a new coal plant, resulting in coal plants from the 1950s remaining in use in 2050 and 2055. A constraint limiting all coal plants to a maximum operational lifetime of 75 years was implemented to reflect more realistic estimates.
- Changed cost of new electricity transmission: the cost in 2005 dollars per GW of new electric transmission capacity was raised from $500 for inter-regional domestic trade and $999 for imports from Canada to $1500 for all new installations, based on our best judgment and comparisons with NREL assumptions (NREL 2012).
- Corrected inaccuracy in structure of the electricity trade representation: an error was discovered in the electricity trade section of the EPAUS9r database that allowed MARKAL to transfer electricity between regions of the U.S. that are not actually interconnected, and could not feasibly be interconnected in the future. This error was verified with EPA and corrected for this study.
- Extensive adjustments to NG supply database: see the next section for details.

IIb. Changes to NG supply database assumptions

Representation of domestic NG supply in the EPAUS9r was modified for this study to improve estimates of emissions from upstream NG production. The unaltered database did not separate NG production between shale and conventional resources. However, emissions may differ between them (Bradbury et al. 2013), so for this study shale gas production was estimated as a fraction of total gas production in each region for 2005-2055. Additionally, this study also uses revised emissions factors for several criteria pollutants and greenhouse gases from the upstream NG sector, and incorporates estimates of the effects of EPA rules that will reduce future emissions from certain processes in the NG supply chain. The changes are detailed below.

IIb.i Regional Shale Gas Production Fractions

NG production emissions factor development for this study depended on levels of shale gas production and conventional gas production in each region: since there is no source distinction in MARKAL for NG as an energy carrier, emissions factors for the NG production stage were weighted by regional shale gas production percentages. These production percentages had to be specified for each time step in the model, so modeling results from two other studies were used in the calculations: unconventional gas production forecasts to 2035 by IHS Global Insight (HIS 2012), and total dry NG production forecasts from EIA's AEO 2013 (EIA 2013). A description of the method used for forecasting regional shale gas production in this study is best presented in list format. In 2010, shale gas production percentages were derived from EIA NG Gross Withdrawals data:

Middle Atlantic (R2): 80%

East North Central (R3): 50%

West North Central (R4): 24%

South Atlantic (R5): 44%

East South Central (R6): 0%

West South Central (R7): 41%

Rocky Mountain (R8): 6%

Pacific (R9): 3%

The percentages are out of total NG production in each region. There is no NG production in the New England states (R1). For 2005, it was assumed that NG production from shale formations is zero in each region. Post-2010, regional shale gas production percentages were forecasted as follows:

1. Dry natural gas production by supply region (including Alaska) was copied from EIA AEO 2013 "High Oil & Gas Resource" case tables. This data was copied for 2011-2040 in five-year increments. There are 7 AEO 2013 oil and gas supply regions: Northeast, Gulf Coast, Midcontinent, Southwest, Rocky Mountain, West Coast, and Alaska. For each of the contiguous regions, this data was taken from the AEO 2013 table "Lower 48 Natural Gas Production and Spot Prices by Supply Region." For Alaska, this data was taken from the AEO 2013 table "Oil and Gas Supply." For each 5-year span in each region, a 5-year growth rate was determined, i.e. natural gas production in the Rocky Mountain supply region will grow ~3.1% between 2020 and 2025.

2. For each producing state registered in the EIA's Natural Gas Gross Withdrawals data for 2011 (EIA 2014), it was assumed that natural gas withdrawals (known for 2011) would increase at the same rate as overall natural gas production for each 5-year period in the corresponding supply region. For example, Pennsylvania is in the Northeast AEO gas

supply region, so it was assumed that natural gas withdrawals in PA would increase at the same percentage rate as overall natural gas production in the Northeast for each 5-year period until 2040. From 2040 to 2055, it was assumed that production would increase at a constant rate equal to that of 2035-2040.

a. For Texas, percentage growth in each 5-year period was an average of the growth rates for the Gulf Coast, Midcontinent and Southwest supply regions since Texas is divided into these three regions in EIA's National Energy Modeling System (NEMS) supply module.
b. Similarly for New Mexico, percentage growth in each 5-year period was an average of the growth rates in the Southwest and Rocky Mountain regions.

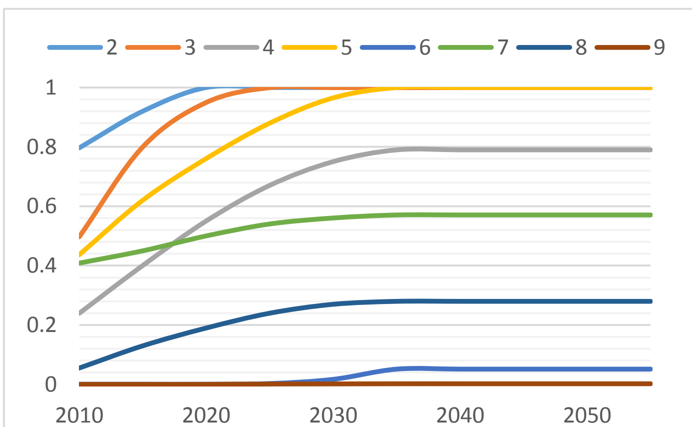
3. At this point, state-level natural gas production (in million cf per year) was calculated for each year from 2011 to 2055 using the above procedure for each producing state in the EIA Natural Gas Gross Withdrawals data for 2011.

4. Finally, the natural gas production totals were added for states comprising each region in the MARKAL database, so that natural gas production projections through 2055 for each region in MARKAL could be calculated. For example, FL, MD, VA, and WV are all states encompassed by region 5 in MARKAL, so to get natural gas production for region 5, the production in each of these states for each year was added together. The Gulf of Mexico withdrawals were assumed to occur in region 7 and Alaska is encompassed by region 9.

5. For each year (5-year gaps) from 2015 through 2035, shale gas percentages were determined based on dividing the unconventional gas production forecasts from IHS Global Insight by the total production calculations determined previously in each census region. If this ratio exceeded 1 for any year, it was lowered to 1. From 2035 to 2055, the percentage of shale gas production in each region was assumed to remain constant.

The results of these calculations for each region were smoothed to project steady and flattening increases in shale gas production fraction. The results are depicted in Figure 1.

Figure 1: Regional shale gas production fractions



IIb.ii Upstream NG Emission Factors

Upstream NG emission factors (EFs) were updated from their values in the unaltered EPAUS9r obtained from EPA for CO_2, CH_4, NO_x, VOC, SO_2, and CO. For CO_2 and CH_4 emissions in 2005 and 2010, carbon footprints assimilated by Weber and Clavin (2012) through Monte Carlo simulations incorporating several previous NG life-cycle assessments were used with slight modifications (Weber and Clavin 2012). Weber and Clavin present CO_2 and CH_4 EFs for three stages of NG production: preproduction, production/processing, and transmission (Weber and Clavin 2012). The NG supply module in the EPAUS9r separates NG production emissions into two categories: production and distribution to end users. For this study, the subtotal of the separate CO_2 and CH_4 EFs from Weber & Clavin for preproduction and production/processing were used for the first stage of NG production in 2005 and 2010, and those for the distribution stage were left unchanged from their original values, derived by EPA from the GREET model database (Argonne 2013).

The GHG EFs from Weber and Clavin were applied separately for conventional gas production and shale gas production. Distinctions between EFs for conventional versus shale gas were determined using the regional shale gas production fractions described above, in the following manner:

EF, ktonne/PJ = (% conventional gas) × (conventional gas EF) + (% shale gas) × (shale gas EF)

This calculation was performed for each individual MARKAL region.

Upstream NG EFs for NO_x, VOC, SO_2, and CO were derived from results of the 2008 baseline-year West-wide Jumpstart Air Quality Modeling Study (WestJump AQMS). From basin-specific emissions inventories and NG production data for the Denver-Julesburg, Piceance, North San Juan, South San Juan, Uinta, Powder River, Southwest Wyoming, Wind River, and Permian basins in the year 2008, EFs for each of these pollutants were calculated and an average weighted by NG production was used across all regions in the model database for this study. In each basin, emissions reported for 2008 were divided by corresponding NG production and multiplied by the NG fraction of the sum of oil, condensate, and gas produced on an energy-equivalent basis. This method assumes that NG-associated emissions of each pollutant are proportional to NG production – not entirely accurate, as some emissions sources are strictly used in NG production and may contribute a much larger share of emissions for certain pollutants than the NG fraction of production would indicate. After basin-specific EFs for each pollutant were determined, I took a weighted average of the EFs using each basin's 2008 NG production as the weights. The results in kilotonnes per PJ (equivalently g/MJ) are presented below.

Table 1: Upstream NG emissions factors, ktonne/PJ

BASIN	GAS FRACTION	NOX	VOC	CO	SO_2
D-J	0.710	0.0493	0.2236	0.0319	0.0003
PICEANCE	0.938	0.0239	0.0543	0.0137	0.0006
NORTH SAN JUAN	0.999	0.0114	0.0042	0.0125	0.0001
UINTA	0.827	0.0258	0.1618	0.0192	0.0007
SOUTH SAN JUAN	0.985	0.0365	0.0471	0.0204	0.0002
POWDER RIVER	0.851	0.0246	0.0173	0.0181	0.0007
SOUTHWEST WY	0.947	0.0109	0.0398	0.0073	0.0027
WIND RIVER	0.893	0.0070	0.0579	0.0109	0.0067
PERMIAN (NM)	0.213	0.0091	0.0475	0.0046	0.0050
	Average:	**0.0208**	**0.0562**	**0.0137**	**0.0017**
	Previous value:	0.0151	0.0007	0.0048	0.0005

As shown, when compared to WestJump AQMS emission factors calculated using this procedure, emissions of VOC were underestimated by almost two orders of magnitude in the unaltered EPAUS9r. Emissions of NO_x, CO and SO_2 were considerably underestimated as well.

IIb.iii Effect of NSPS/NESHAP on Regional VOC and Methane Emission Factors

In estimating the VOC and methane emission reductions expected to result when the new rules take effect in 2015, the EPA separated equipment or processes that will be affected by the rules into several categories: hydraulically fractured and refractured gas well completions, equipment leaks, reciprocating and centrifugal compressors, pneumatic devices, and storage vessels (Regulatory 2012). For each of these categories, EPA published estimated emission reductions in 2015 for VOC and methane in short tons in its Regulatory Impact Analysis of the NSPS and NESHAP rules (Regulatory 2012). For the purposes of this study, EPA's estimates were combined with NG production forecasts by the EIA in order to develop yearly emission factor reductions for methane and VOC starting in 2015. For each category, the method used to develop the EF reduction is described below.

Gas well completions

The NSPS for the upstream oil and gas sector requires that all hydraulically fractured (HF) well completions and recompletions starting in 2015 use gas capture techniques, or RECs, when the pressure in the well is sufficient; otherwise, combustion of vented gas will be required (Regulatory 2012). Since all well completions and recompletions starting in 2015 will be subject to the EPA rules, the resulting VOC and methane reductions will scale with the number of well completions and recompletions. Stated directly in the EPA's Background Supplemental Technical Support Document (TSD) for the Final NSPS, the expected VOC reduction is 21.5 tons per individual HF well completion, and the average methane reduction is 147.86 tons per individual HF well completion (Oil and Natural Gas 2012). In order to develop an EF reduction in units of mass per NG energy-equivalent, a ratio of HF well completions to HF gas produced was applied to these estimates. There are a few stipulations, as described in the TSD in Chapter

5: some HF wells do not have sufficient pressure to perform a REC, others are already subject to state regulations in CO and WY, and still others use RECs voluntarily (Oil and Natural Gas 2012). In any of these completions, the new rules would not result in a reduction in emissions. In the calculation for this study, the EPA's "primary baseline case" assumption was used: that the number of completions being performed with RECs voluntarily would remain the same if the NSPS/NESHAP rules did not exist (Regulatory 2012).

According to the EPA, the numbers of well completions and recompletions in 2015 with sufficient pressure to perform an REC, not already subject to state regulations, and not already performing RECs voluntarily are 4,107 and 532, respectively (Oil and Natural Gas 2012). In addition to these completions, however, completions that cannot use an REC but that must use combustion to reduce emissions must also achieve equivalent VOC & methane reductions. The estimated number of well completions using combustion to achieve the required 95% reduction is given by the EPA as 1,377, and the number of well recompletions using combustion was backed out from the reduction given in Table 3-4 of the RIA. To do this, I took the VOC reduction given (2,602 tons) and divided it by the required VOC reduction per completion or recompletion (21.5 tons) to get 121 recompletions.

Thus, the total number of completions and recompletions in 2015 that will be affected by the NSPS/NESHAP rules were estimated: 4,107 completions eligible for RECs, 532 recompletions eligible for RECs, 1,377 completions using combustion, and 121 recompletions using combustion gives 6,137 total well completions. With the amount of NG production coming from HF wells in 2015, the reductions given by EPA yielded emission factor reductions. In EIA's AEO 2014, the NG production projection for 2015 coming from shale gas, tight gas, and CBM wells (which EPA assumes all use HF) is 16.8 Tcf (EIA 2014). Therefore the assumption was made that there will be 6137/16.8 = ~365.25 affected well completions per Tcf NG produced going forward. This calculation yields a VOC emission factor reduction in kt/PJ and the same for methane: 0.0066 and 0.0451 kt/PJ, respectively. These reductions were applied to the shale gas EFs for VOC and methane used in 2010, before the NSPS and NESHAP rules take effect, of 0.0562 and 0.276 kt/PJ, respectively, to yield VOC and methane EFs for gas produced using hydraulic fracturing subject to the green completion requirement: 0.0496 kt/PJ for VOC and 0.2309 kt/PJ for methane.

Storage vessels

EPA estimated the nationwide emission reductions resulting from the new requirements for condensate and crude oil storage vessels in its 2012 TSD (Oil and Natural Gas 2012). For the purposes of this study, only the absolute reductions expected for condensate storage tanks were used, as these were assumed to apply only to NG production as opposed to both oil and NG production. EPA gives the VOC and methane reductions in short tons per year as 15,061 and 3,296, respectively (Oil and Natural Gas 2012). The calculated EF reduction for this category was derived in a similar manner to the reduction from the REC requirement, dividing the absolute VOC and methane reductions in tons per year by the expected total NG production estimate from EIA, with a modification to account for the fact that only new storage vessels will be subject to the rules. For this category and the remaining categories, a straight line phase-in from 2015 to 2030 was used to estimate the VOC and methane reductions that will result from new equipment replacing older equipment not subject to the upstream oil and gas NSPS/NESHAP. It was assumed that in 2030, all equipment not subject to the rules will have been replaced, meaning that the full reduction from the rules will have taken effect for both shale and conventional gas EFs. The EF reductions were calculated as follows:

2015 reduction = (absolute VOC/CH4 reduction)/(2015 NG production)

2030 reduction = (2015 reduction) × 15 × (2030 NG production/2015 NG production)

The NG production estimates used were taken from EIA's AEO 2014 Reference Case modeling results for total U.S. dry natural gas production. For the years 2020 and 2025, linear interpolation was used to calculate the EF reductions. These reductions were subtracted from the 2010 shale and conventional gas EFs for VOC and methane to reach constant values in 2030. The results of the calculation are as follows:

	2015	2020	2025	2030
EF reduction, VOC, kt/PJ	0.000511	0.003912	0.007313	0.010714
EF reduction, methane, kt/PJ	0.000112	0.000856	0.001600	0.002345

Compressors

The reductions expected to occur in 2015 from requirements for new compressors were published by the EPA in the 2012 RIA as 1736 and 8139 tons per year of VOC and methane, respectively (Regulatory 2012). For this study, all of the reductions were assumed to apply to upstream NG production rather than oil production. Using the same technique that was applied for reductions from storage vessels, the results are as follows:

	2015	2020	2025	2030
EF reduction, VOC, kt/PJ	0.000059	0.000451	0.000843	0.001235
EF reduction, methane, kt/PJ	0.000276	0.002114	0.003952	0.005790

Equipment leaks

The reductions expected to occur in 2015 from requirements for addressing equipment leaks were published by the EPA in the 2012 RIA as 132 and 475 tons per year of VOC and methane, respectively (Regulatory 2012). For this study, all of the reductions were assumed to apply to upstream NG production rather than oil production. Using similar techniques as above, the results are as follows:

	2015	2020	2025	2030
EF reduction, VOC, kt/PJ	0.000004	0.000034	0.000064	0.000094
EF reduction, methane, kt/PJ	0.000016	0.000123	0.000231	0.000338

Pneumatic devices used at natural gas processing plants

The absolute VOC and methane emission reductions expected to occur in 2015 from regulations affecting pneumatic devices used at NG processing plants were given in the EPA's 2012 RIA as 63 and 225 tons per year, respectively (Regulatory 2012). The EF reduction results calculated using the same techniques as applied above are as follows:

	2015	2020	2025	2030
EF reduction, VOC (kt/PJ)	0.000002	0.000016	0.000031	0.000045
EF reduction, methane, kt/PJ	0.000008	0.000058	0.000109	0.000160

Pneumatic devices used in natural gas production

In specifying the VOC and methane reductions expected to result from regulations affecting pneumatic devices used in oil and NG production, the EPA did not distinguish between reductions from equipment used in NG production and reductions from equipment used in oil production. Thus, in order to calculate EF reductions for upstream NG only, a weight had to be applied to the expected reductions that took into account the relative contributions to VOC and methane emissions of pneumatic devices used in NG production versus those used in oil production. The weight used was the amount of methane emissions from pneumatic devices in the NG sector divided by the sum of methane emissions from pneumatic devices in the NG & petroleum sectors published in Annex 3 of the 2013 EPA U.S. Inventory of Greenhouse Gas Emissions and Sinks (Inventory 2014). Methane emissions from 2012, the latest year for which estimates were made in this publication, were used: 257.1 Gg for natural gas, and 435 Gg for petroleum. The NG weight applied to the emission reductions estimated by EPA was therefore 0.37. The EF reduction results using techniques described previously are then as follows:

	2015	2020	2025	2030
EF reduction, VOC, kt/PJ	0.000318	0.002433	0.004547	0.006662
EF reduction, methane, kt/PJ	0.001143	0.008750	0.016358	0.023965

Summary of nsps/neshap emission factor reductions

The EF reductions were subtracted from 2010 VOC and methane EFs for shale and conventional gas, and the resulting EFs for each year were then applied to regional shale and conventional gas fractions to yield final EFs for each region and each time step. The first category for reductions, the REC requirement, only applied to shale gas EFs. The rest of the reductions were applied to both shale and conventional gas EFs. The calculation for the final regional VOC or methane EF defined for MARKAL is as follows:

Final MARKAL EF = (shale gas fraction) × (shale gas EF) + (conventional gas fraction) × (conventional gas EF)

IIc. Scenarios

Listed in Table 2, a diverse set of scenarios was developed for this study to examine how emissions from natural gas production and use might change in coming decades, based on different assumptions about resource supply, demand for natural gas, and policy measures to reduce emissions or limit fossil fuel use in the electric power sector. The scenarios are designed as clusters of modifications to inputs and parameters in the EPA MARKAL model that might reasonably be expected to occur together – e.g., parameters that tighten supplies of natural gas are combined with higher prices in one scenario, while parameters that reduce costs for renewable energy technologies are combined with representation of policies that accelerate their use. The modeling inputs that comprise each scenario are described in the following section.

Table 2: MARKAL scenario descriptions

NAME	DESCRIPTION
CHEAP GAS	Abundant NG supply, increased shale gas production, low wellhead costs
COSTLY GAS	Limited NG supply, reduced shale gas production as percentage of overall gas production, high wellhead costs
FOSSIL CAP	Share of electricity generated by fossil fuels decreases to 20% by 2050; optimistic price assumptions for certain renewable technologies
GHG FEE	A “tax” on carbon emissions from each energy sector is implemented from 2015-2050
COAL RETIREMENTS	No new coal plants may be built starting in 2015, and existing coal plants are retired at an accelerated rate
CNG VEHICLES	Penetration of CNG-fueled vehicles increasing to 100% by 2050 in buses, heavy-duty short haul trucks, and light-duty fleet vehicles

IIc.i NG Supply Scenarios: Cheap Gas and Costly Gas

Two scenarios characterizing natural gas supply and price through 2055 were designed to examine contrasting assumptions about future natural gas production. The scenario assumptions incorporate changes to the wellhead cost of NG, allowed rates of yearly production and reserve depletions, and regional fractions of NG production coming from shale deposits.

Wellhead Prices

The representation of domestic NG supply in MARKAL is explicitly defined by regional stepped supply curves. The model may use gas at a specified price up until a defined limit, at which point the gas becomes more expensive, and so on for six supply steps. Supply bounds for each step are defined for 2005 and 2010, and calculated by the model in later years based on resource growth and decay parameters. For the Cheap Gas and Costly Gas scenarios, regional wellhead prices in the third step of each region's supply curve were specified based on the results of the EIA AEO 2013 "High Oil and Gas Resource" and "Low Oil and Gas Resource" cases (EIA 2013). These prices are presented as Lower 48 Onshore Spot Prices in 2011 dollars per thousand cubic feet in AEO 2013. The model inputs in MARKAL were derived from AEO 2013's results by first converting them to the appropriate units (MARKAL uses 2005 dollars per Petajoule) and then applying them to the nine regions in the EPAUS9r using weighted averages, since the six gas supply regions in EIA's NEMS model fuel supply module do not contain the same geographical areas as the nine regions in EPAUS9r. MARKAL regions contained within NEMS regions were assigned the price corresponding to the containing region, and MARKAL regions containing parts of two or more NEMS regions were assigned a weighted average price using the prices of each NEMS region and the corresponding dry NG production from AEO 2013 in that region as weights. For example, region 7 in MARKAL (West South Central) contains parts of the Gulf Coast, Midcontinent, and Southwest gas supply regions in NEMS, so the wellhead price for gas extracted in MARKAL region 7 would be a weighted average of the AEO 2013 spot prices in those NEMS regions for each year. Table 3 displays the source(s) in AEO 2013 for each MARKAL region's NG wellhead prices.

Table 3: EIA NEMS Region to MARKAL Region Mapping

MARKAL Region	NEMS Region(s) used
R1 (New England)	Northeast
R2 (Middle Atlantic)	Northeast
R3 (East North Central)	Northeast
R4 (West North Central)	Midcontinent
R5 (South Atlantic)	Northeast
R6 (East South Central)	Northeast, Gulf Coast
R7 (West South Central)	Gulf Coast, Midcontinent, Southwest
R8 (Mountain)	Rocky Mountain
R9 (Pacific)	See below

For R9, MARKAL wellhead price was an average of West Coast and Lower 48 Average prices from AEO 2013, using production from West Coast and Alaska as weights, respectively.

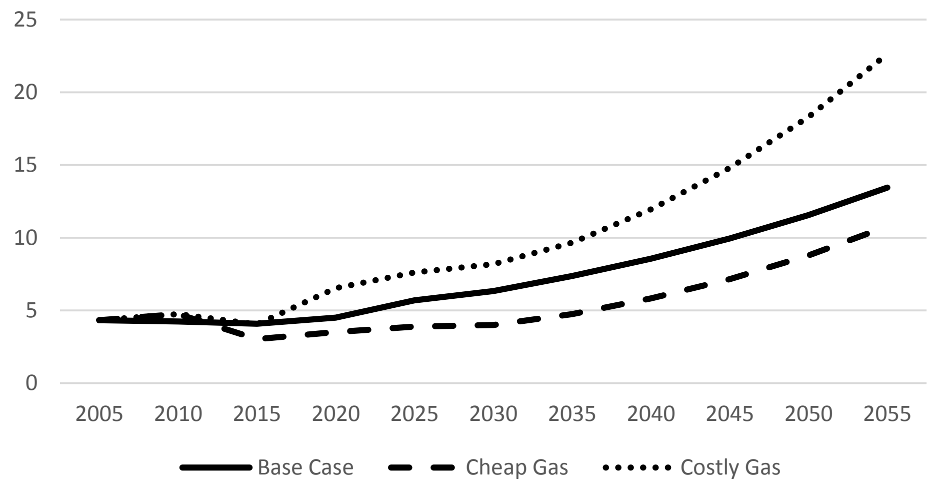
AEO 2013 projections stretch through 2040, and start in 2010. Since MARKAL's model time frame spans from 2005-2055, prices in years not projected by AEO 2013 for the Costly Gas and Cheap Gas scenarios had to be extrapolated. For 2005, the wellhead prices were unchanged from the base case inputs. For 2045-2055, the prices were set to grow at the same percentage rate per five-year period as the AEO 2013 projections for 2035-2040.

To build NG supply curves in each region for these two scenarios, multipliers were applied to the prices derived from AEO. See below for the multiplier applied to each supply curve step.

Step	Multiplier
1	0.88
2	0.998
3	1
4	1.003
5	1.12
6	1.53

Region 8 wellhead prices (supply step 3) that were used as inputs to MARKAL for the base case, Cheap Gas and Costly Gas scenarios are depicted in Figure 2.

Figure 2: Region 8 Natural Gas Wellhead Cost, $/MMBtu



Resource supply parameters: growth and decay

In addition to price, NG supply characteristics were also altered for the Cheap Gas and Costly Gas scenarios in MARKAL. The model input parameters used to characterize the supply were the maximum decline rate (MDR) and the maximum growth constraint (MGC).

The MDR is the reserves-to-production ratio that limits the amount of oil or gas that may be used by the model in a given year (EPA 2013). The MDR is set to prevent MARKAL from using all available gas when it is least expensive, forcing a smooth decline rate in production (EPA 2013). For the Cheap Gas scenario, the MDR was adjusted to be slightly closer to 1 than in the base case, effectively raising the cap on yearly NG production. For the Costly Gas scenario, the MDR was increased so that less gas would be available to the model each year.

The MGC does not constrain NG *use* in the model, but limits the amount of new resource that becomes available to the model each year (EPA 2013). For oil and gas, the MGC essentially limits the rate of growth in inter-annual production by constraining the percentage of total existing reserves that become available for production each year. Since the MDR specifies the maximum production as a percentage of reserves available to MARKAL, its effect depends on the MGC. In the Cheap Gas scenario, the MGC was relaxed to allow more rapid inter-annual growth in production, and tightened slightly for the Costly Gas scenario to achieve the opposite effect. The degree to which these two parameters should be changed to elicit the desired supply characterization was determined through sensitivity analyses. For the base case, Cheap Gas, and Costly Gas scenarios, the values for the MGC and MDR that were chosen as model inputs for NG supply in MARKAL are presented in Table 4. The MGC varies from region to region depending on the NG resource available. Since no recoverable reserves of NG currently reside in region 1 (Northeast), supply parameters do not apply to this region.

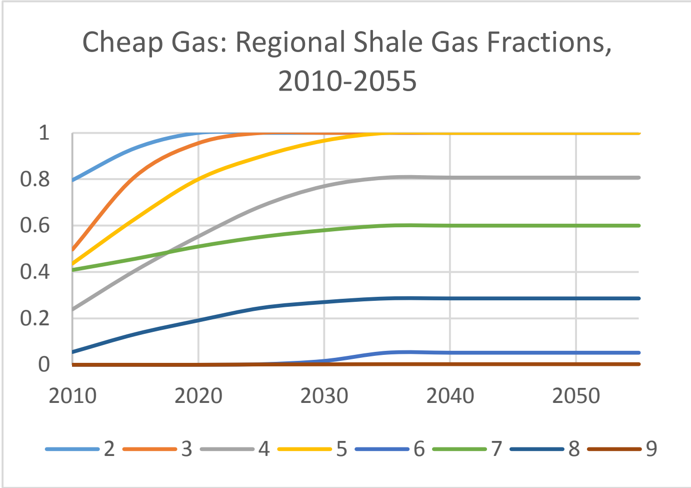
Table 4: MDR and MGC used in base case, Cheap Gas & Costly Gas scenarios

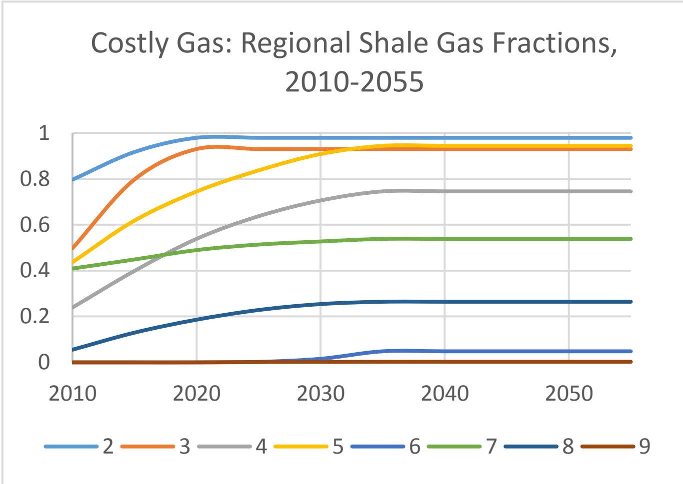
Scenario	**MDR**	**MGC**
Base Case	1.01	1.05 (R2,R3,R5); 1.005 (R4,R6,R7,R8,R9)
Cheap Gas	1.001	3
Costly Gas	1.1	1.025 (R2,R3,R5); 1.0025 (R4,R6,R7,R8,R9)

Shale gas production fraction changes

In the Cheap Gas scenario, where abundant NG supply was modeled in order to increase NG production in each region, shale gas production fractions were also adjusted upward to reflect increased drilling access to unconventional NG resources. Equivalently for Costly Gas, shale gas production fractions in each time step and region were adjusted downward from the base case. Adjusted shale gas production fractions for the NG supply scenarios affected NG production EFs for GHGs and VOC in these scenarios. I used NG production modeling results from the AEO 2013 “High Oil & Gas Resource” and “Low Oil & Gas Resource” cases as well as the AEO 2013 reference case to determine yearly scaling factors to be applied to the base case shale gas production fractions in each region (EIA 2013). Starting with AEO 2013 results from the Oil and Gas Supply table, the subtotal of NG production from tight gas, shale gas, and coalbed methane was divided by the United States Total NG production in each 5-year time step from 2015-2040 to produce unconventional gas fractions for each of the AEO 2013 cases. Next, for each time step, a scaling factor equal to the percentage change above or below the reference case shale gas fraction for the High Oil & Gas Resource and Low Oil & Gas Resource cases, respectively, was determined. Finally, these scaling factors were applied to the base case shale gas fractions to produce regional shale gas fractions for the Cheap and Costly Gas scenarios. Beyond 2040, shale gas fractions were held constant.

The shale gas fractions calculated for the Cheap Gas and Costly Gas scenarios are presented for each region below:





Lower bound on Region 8 NG Production

Preliminary MARKAL runs of Cheap Gas resulted in unchanged or decreased NG production in R8, presumably due to a combination of factors including inter-regional trade of NG reacting to changes in the MDR and MGC for each region. In order to analyze the emissions impacts of greater NG production in the Rocky Mountain region, a lower bound on NG production in R8 was implemented via an activity constraint in MARKAL. This constraint forced MARKAL to produce a minimum number of PJ of NG within R8. The values of the lower bounds were calculated starting in 2015 by applying scaling factors to the MARKAL base case levels of NG production. These scaling factors were derived from EIA data: the levels of NG production in the Rocky Mountain region in the AEO 2013 “High Oil and Gas Resource” case were compared to those in the AEO 2013 reference case, and the resulting scaling factors were used from 2015-2040 as a MARKAL constraint. From 2040-2055, the lower bounds on R8 NG production were assumed to grow at approximately the same rate as the 2035-2040 growth rate.

IIc.ii Fossil Cap scenario

The Fossil Cap scenario depicts an accelerated transition away from fossil fuel technologies for electricity generation. Such a shift could be achieved by more aggressive renewable portfolio standards or passage of national carbon cap-and-trade legislation, however, instead of attempting to model these mechanisms in MARKAL, we simply directly specified a constraint that would loosely reflect a transition away from fossil fuels in the electricity mix. The scenario was implemented by using optimistic cost assumptions for certain renewable technologies and adding constraints on the share of electricity generated by fossil fuel technologies. Other model parameters were also adjusted to simulate realistic renewable electricity supply limitations in an electricity mix with high renewable penetration.

Constraints

A global upper bound on the share of electricity generated by fossil fuel technologies limits the cumulative amount of fossil fuel electricity generated in the nine regions in MARKAL by imposing an upper bound on energy generated by electricity technologies using fossil fuel sources as a percentage of total electricity generated. The upper bound was specified at 60% in 2015 and 50% in 2020, decreasing 5% per 5-year period thereafter to 20% in 2050 and 2055. It is input as a “global” constraint as opposed to a regional constraint, which means that the specific upper bounds do not apply to electricity generated region-by-region, only to the sum total of electricity generated in all the regions. Thus, the constraint need not be satisfied in every region in the model solution. Additionally, the scenario is described as a cap on fossil fuels, or transition away from fossil fuels, instead of a lower bound on renewables. This is due to the fact that several technologies that may not be traditionally referred to as either fossil fuel or renewable technologies are not subject to the constraint, including nuclear, municipal solid waste, landfill gas, and hydropower.

Regional upper bounds on the share of electricity generated by wind and solar PV technologies were also implemented as constraints. Preliminary runs indicated that when subject to the fossil cap constraint in the long term, MARKAL would tend to choose wind or distributed solar PV as primary means of electricity generation in several regions due to the low capital costs of these technologies compared to the alternatives. In several regions, the electricity mix consisted of up to 90% wind or solar PV which is unrealistic from a grid integration standpoint (NREL 2012). The MARKAL base case, using the unaltered USEPA9r database originally obtained from EPA for this study, contains resource-related constraints that affect renewable energy technologies including wind and solar PV, as well as a limited representation of the relationship between the available capacity of these technologies and time-variant electrical load. In addition to these constraints already present in the base case, a regional constraint on electricity generation by variable technologies was implemented for this scenario and others characterized by high renewables penetration. For each region, this constraint specified that the sum of electricity generated by wind and solar PV technologies must comprise no more than 50% of the electricity mix.

Capacity value parameter: peak availability of variable generation technologies

As penetration of variable generation technologies (wind and solar PV) into the electricity mix increases, grid reliability becomes a concern. Since electricity generated by these technologies is intermittent, grid operators must make conservative estimates of the amount of variable capacity they can count on during periods of peak demand, which do not necessarily correspond to periods of high solar insolation or heavy winds. Thus, integration of high levels of wind and solar PV capacity into electrical grids necessitates a minimum level of dispatchable capacity, which may be ramped up or down depending on the level of variable generation and expected demand (NREL 2012). For variable generation technologies, the fraction of the technology's installed capacity that grid operators can rely on during times of peak demand is referred to as the capacity value. To account for uncertainty in electric generation from wind and solar at any given time, capacity values are typically quite low, and decrease as grid penetration of wind and solar increases and the electricity supply becomes more sensitive to generation intermittency (Sullivan 2013).

In regions featuring growing penetration of wind and solar PV into the electricity supply mix, regional capacity values for these technologies were exogenously defined in four separate bins depending on grid penetration. First, the scenario was run with constant capacity values. For each region and time step, the capacity value was then fixed at one of four values depending on the technology and the grid penetration. The assumptions used are depicted in Table 5, and were chosen using my best judgment. These were used in most regions in Fossil Cap, and fewer regions in each of the other scenarios, including the base case.

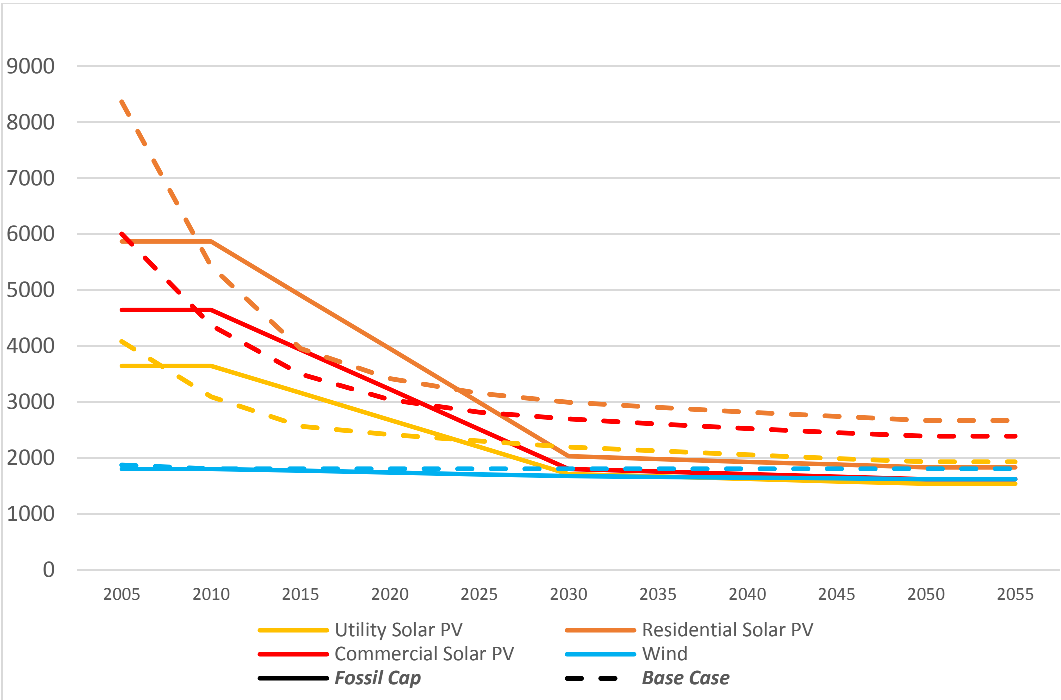
Table 5: Wind and solar PV capacity values vs. grid penetration

Grid penetration	Wind capacity value	Solar PV capacity value
0-10%	.15	.30
10-20%	.10	.20
20-25%	.05	.10
>25%	0	0

Capital and Operation & Maintenance Costs

Assumptions for the Fossil Cap scenario were designed to be consistent with future technological advancements and considerable cost reductions for renewable technologies most likely to replace constrained electricity generation from fossil fuels. Thus, base case cost assumptions for onshore wind and solar PV technologies available to MARKAL were replaced with corresponding cost assumptions from the most optimistic 80% renewables penetration scenario formulated in the 2012 NREL Renewable Electricity Futures Study, "RE – Evolutionary Technology Improvement (80% RE–ETI)" (NREL 2012). For remaining electricity generation technologies, cost assumptions came from Black and Veatch 2012 and assumptions to EIA's AEO 2013 (Black and Veatch 2012; EIA 2013). Capital costs from NREL were converted from 2009 USD per kW to 2005 USD per kW. Fixed O&M costs were converted from 2009 USD per kW-year to 2005 USD per kW-year. Variable O&M costs were converted from 2009 USD/MWh to 2005 USD/PJ. These costs were used as MARKAL model inputs for 2005-2055, uniform across all regions. Since RE Futures projected costs from 2010-2050, MARKAL inputs for Fossil Cap in 2005 and 2055 were assumed to be equal to costs in 2010 and 2050, respectively. Capital cost inputs for wind and solar PV technologies are displayed in Figure 3 for Fossil Cap, along with corresponding base case cost assumptions for comparison.

Figure 3: Capital cost assumptions for renewable energy technologies in base case vs. Fossil Cap scenario, 2005-2055, 2005 $/kW



IIc.iii GHG Fees scenario

An effective "tax" on system-wide carbon emissions was implemented for the GHG Fee scenario starting in 2015. An added cost associated with emission of any pollutant defined in MARKAL can be implemented as a model input defined in USD per metric tonne emitted. This parameter is then applied by MARKAL to any process technology emitting the taxed pollutant, which increases the cost of each unit of energy services provided by that technology. For the

GHG Fee scenario, a tax on carbon emissions was applied based on the mid-range estimates for "Social Cost of Carbon" published by the United States Government Interagency Working Group on Social Cost of Carbon (SCC) in May 2013 (Interagency 2013). The SCC is a metric used by various regulatory agencies in the U.S. to assess climate benefits of policy mechanisms; it provides a measure of economic damages caused by climate-change related impacts projected to occur as a result of successive increases in carbon emissions (Interagency 2013). For the GHG Fee scenario in this study, the SCC using a discount rate of 3% was used, representing the mid-range of estimates published for the years 2015 through 2050. The fee was kept constant for 2050-2055.

To implement the GHG tax in MARKAL, the SCC values were converted from 2011 USD per metric tonne to 2005 USD per metric tonne, and applied for CO_2 and methane (CH_4) using a 100-year global warming potential (GWP) of 25. This GWP was used in order to remain consistent with several other data sources used in this study including Bradbury et al. 2013 and Weber & Clavin 2012. The GWP essentially implies that in terms of climate change impacts on a 100-year timescale, one tonne of CH_4 emitted is equivalent to 25 tonnes of CO_2 emitted[1]. Thus, the fee applied to system-wide CH_4 emissions was equal to 25 times the fee applied to system-wide CO_2 emissions on a mass basis. The GHG fees used as model inputs for this scenario are presented in Table 6.

[1] The Intergovernmental Panel on Climate Change (IPCC) updated methane GWPs in the recent publication of its Working Group I's contribution to the Fifth Assessment Report (WGI AR5) available at http://www.climatechange2013.org/, from 72 to 84 for a 20-year GWP and from 25 to 28 for a 100-year GWP.

Table 6: Emissions taxes applied for the GHG Fee scenario, 2005 dollars per metric tonne

	2015	2020	2025	2030	2035	2040	2045	2050
CO2	32	36	40	44	48	52	56	60
CH4	792	911	1010	1109	1209	1308	1407	1506

The fees were applied for carbon-equivalent emissions across all regions in the model from every sector: electric, industrial, commercial, residential, and transportation.

IIc.iv Coal Retirements scenario

The Coal Retirements scenario features a moratorium on post-2010 construction of new coal steam power plants and accelerated retirements of existing coal capacity, outcomes that seem plausible in the near future as a result of proposed EPA rules for new and existing power plants that limit carbon emissions (EPA 2013). These levels were chosen as roughly double the capacity retirements projected by EIA's AEO 2013 reference case for 2025, with additional capacity retirements following through 2055 (EIA 2013). The constraints were applied solely to traditional steam power plants, allowing coal-fired combined heat and power (CHP) plants or integrated gasification combined cycle plants to remain available to MARKAL.

Constraints

In the MARKAL Base Case, approximately 312 GW of coal-fired electric capacity exists in 2010. This capacity mostly consists of coal plants built before 2010, referred to as residual capacity. The EPAUS9r database has a detailed representation of these existing coal plants with their operational details, costs, and capacities pre-loaded into the model. In 2010 new coal-fired steam power plants become available to MARKAL. To actualize a moratorium on MARKAL's construction of new coal plants, region-specific upper bounds on electric generation from new coal plants equal to the existing 2010 generation were implemented as constraints. Therefore, new plants that were built by the model in 2010 were not subject to the constraints. These constraints effectively prevent coal-fired electricity generation from increasing after 2010.

Additionally, a global upper bound on coal electricity phasing in in 2025 was applied so that MARKAL could choose to retire coal plants in any combination of the 9 regions in order to satisfy the constraint. In AEO 2013, EIA projects that roughly 40 GW of existing coal capacity is will be retired by 2025 (EIA 2013). Constraints implemented for Coal Retirements in MARKAL were designed to accelerate these retirements to double this level with an additional 20 GW retired in the following 25 years. Iterative model runs were performed with constraints on electricity generation from coal until these levels of capacity reductions were approximately reached.

IIc.v CNG Vehicles scenario

Currently occupying a marginal segment of the wide range of vehicle technologies available to consumers, vehicles fueled by compressed NG (CNG) are expected to reach increased penetration into the fuel mix partly due to price disparities between NG and diesel/petroleum on an energy equivalent basis (MIT 2011). The CNG Vehicles scenario explores the implications of increased demand for natural gas in the transportation sector, with the assumptions that CNG attains 100% penetration by 2050 in two heavy-duty vehicle (HDV) categories: short haul trucks and buses, along with 100% penetration by 2050 in light-duty vehicle fleets of 10 or more, which may include state or federally-owned vehicle fleets as well as commercial fleets.

Constraints

LDV representation in the USEPA9r is divided into categories by technology type (i.e. compact, mini-compact, full size sedan, SUV, etc.) and by fuel type (hybrid, conventional gasoline, diesel, CNG, etc.). Since no distinction is made between vehicles in fleets and personally owned vehicles, a lower bound on CNG vehicles in fleets was defined by first determining the fraction of all LDV vehicle-miles traveled (vmt) contributed by fleet vehicles throughout the model time frame. The relevant data were obtained from AEO 2013 Reference Case tables "Transportation Fleet Car and Truck Vehicle Miles Traveled by Type and Technology" and "Light Duty Vehicle Miles Traveled by Technology Type" (EIA 2013). Past the end of EIA projections in 2040, the 2035-2040 percentage growth rate for vmts in each category, transportation fleet vehicles and total LDVs, was applied for 2045 and 2050. Fleet vmts were then determined as a percentage of total LDV vmts in 2050, and used as a lower bound on vmts for CNG vehicles in 2050. The constraint was phased in in steps starting in 2020 at 1% share of total light-duty vmt in 2020 (corresponding to 14% of fleet vmt) and rising to a 6.2% share of total LDV vmt in 2050 and 2055 (corresponding to 100% of fleet vmt). It was implemented as a global constraint, allowing MARKAL to satisfy it by deploying CNG vehicles in any combination of regions without having to meet the requirement in each individual region.

Lower bounds on vmts for CNG technology buses and short haul trucks were specified starting in 2015 as percentages of all vmts for the bus and short haul truck categories, respectively. The specified constraints increased to 100% of vmts in these categories by 2050, and remained at that level in 2055. Refer to Table 7 for constraint values for CNG buses and short haul trucks by year.

Table 7: Constraints on vehicle-miles traveled by CNG buses and CNG short haul trucks as percentage of total vehicle-miles traveled by buses and short haul trucks

Year	**Constraint (% of all bus/truck vmt)**
2015	5
2020	15
2025	30
2030	45
2035	60
2040	75
2045	90
2050	100
2055	100

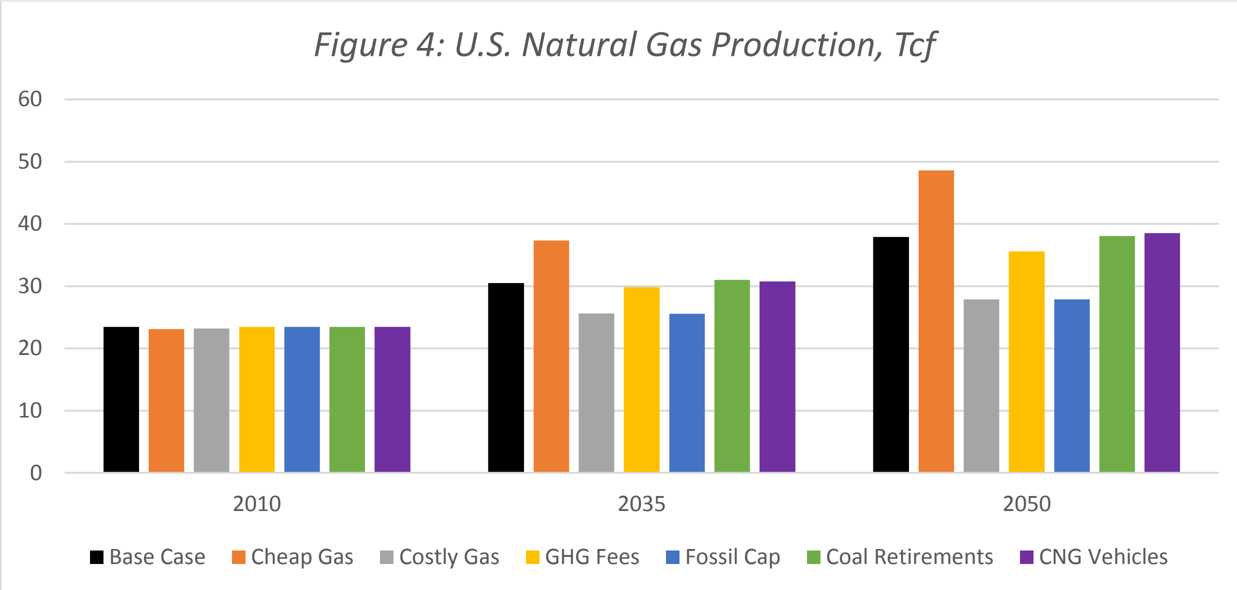
III. Results

The MARKAL modeling results for each scenario are presented here. The sets of results informing this analysis include NG production, mix of technologies comprising electricity supply, and emissions of GHGs, NO_x and VOC. The results are separated between those for the Rocky Mountain region (sometimes referred to as R8), and for the U.S. as a whole. Many of the regional trends and their explanations are discussed in the context of the corresponding national results. All results are presented in the time frame 2010-2050.

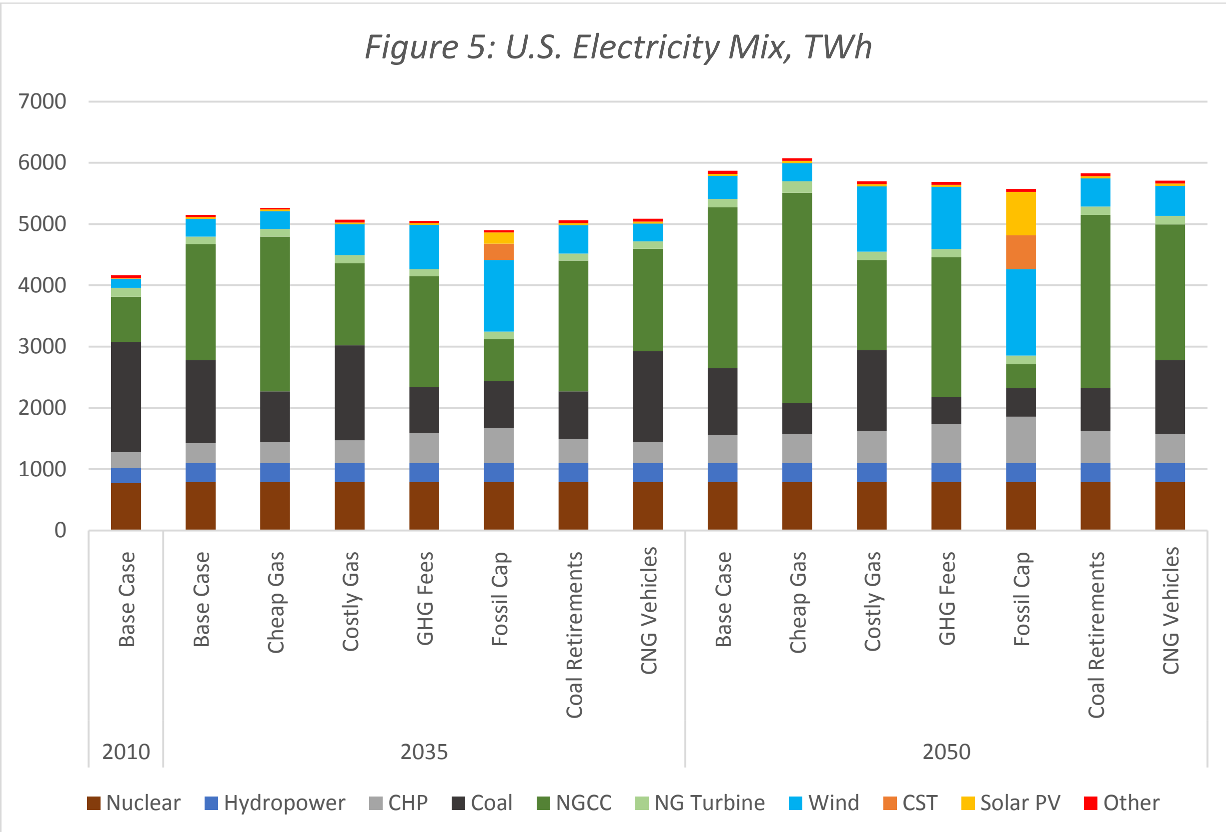
IIIa. NG Supply Scenarios: Cheap Gas & Costly Gas

IIIa.i National Results

NG production trends among the base case, Cheap Gas, and Costly Gas follow from the scenario assumptions: the largest growth in production occurs in Cheap Gas (110% from 2010-2050), followed by the base case (61%) and Costly Gas (20%) (Fig. 4). NG production grows consistently from year to year in Costly Gas despite assumptions representing comparatively high wellhead costs and limited access to new areas for drilling. Cheap Gas features a particularly steep increase in production in the short term, 62% from 2010-2035.



Significant results in the national electricity mix for the NG supply scenarios include the varying degrees of fuel switching from coal to NG, as well as the competition between wind and NG for meeting electricity demand in the long term. Fuel switching occurs in the short term in both Cheap Gas and Costly Gas as well as the base case (Fig. 5). In Cheap Gas, this fuel switching is more extensive: by 2035, electricity generated by NG combined cycle turbines has replaced over half of the 2010 coal electricity. Fuel switching takes place to a lesser degree than the base case or Cheap Gas in the Costly Gas scenario, where wind also becomes more prominent in meeting electricity demand especially in the long term. In Costly Gas, after 2035 additional electricity demand is met with wind instead of NG. This shift in the electricity mix observed when comparing Costly Gas to the base case loosely indicates a price point at which electricity from wind becomes economically favorable over electricity from NG. MARKAL's electricity mix solutions in 2035 for the two scenarios indicate that this is the first year in which additional electricity demand is met primarily by wind instead of NG in Costly Gas. In 2035 in Costly Gas, the average delivered cost of NG to the electric sector, weighted by regional NG production, is $9.46/mcf. This is nearly double the recorded delivered NG price for the electric sector in EIA's AEO 2013 of $4.87 in 2011 (EIA 2013). This result indicates that even in a scenario featuring considerably high fuel costs, electric sector NG remains the cheapest energy source until 2035, when the delivered fuel price reaches roughly twice its current value and wind becomes more competitive.



U.S. GHG emissions in the MARKAL base case are about 1.5% higher in 2050 than in 2010, after a modest decline in the interim (Fig. 6)[2]. This increase is driven by steadily increasing demand for energy services that are primarily met with fossil fuels in the industrial and commercial sectors. GHGs released during extraction of oil and gas also contribute to the trend.

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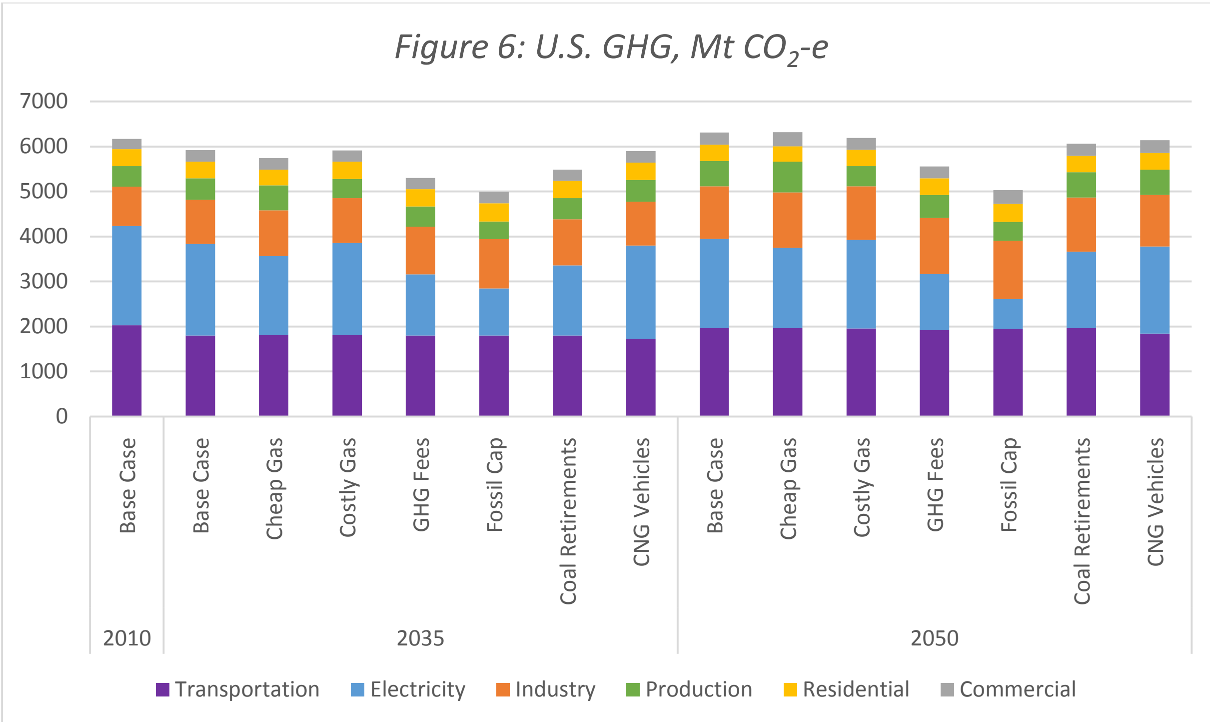
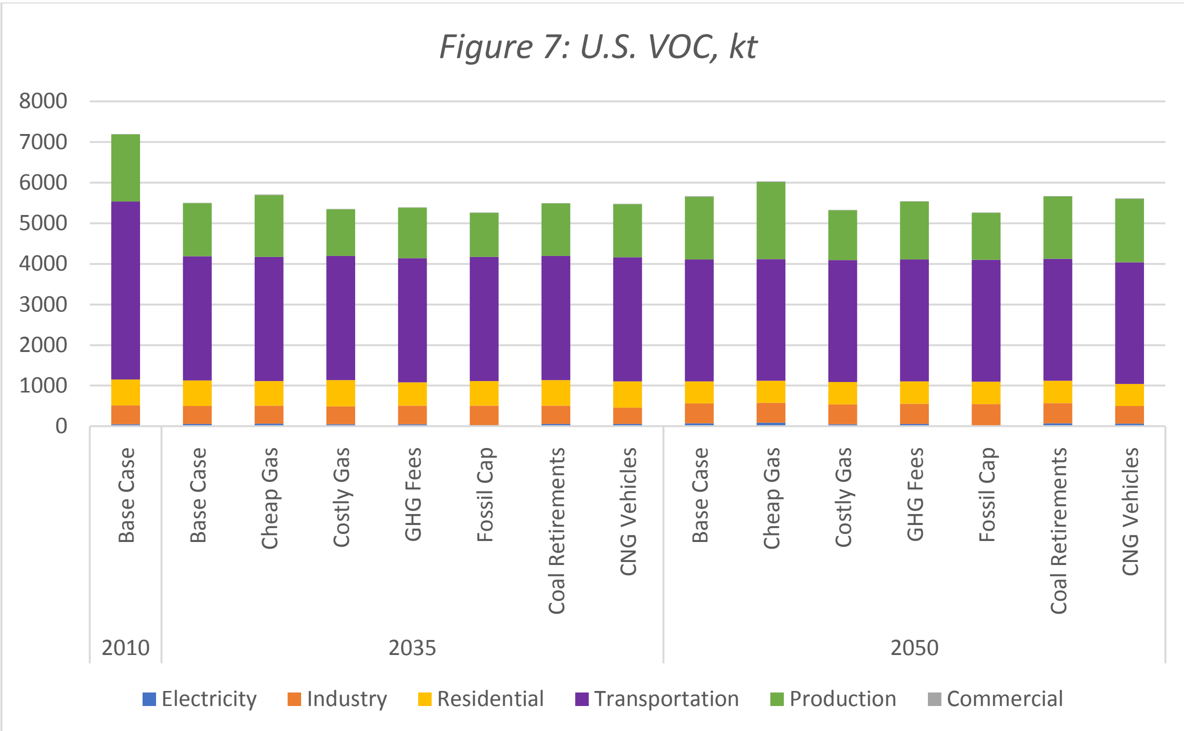
[2] Unless otherwise specified, GHG emissions in this study have units of tonnes CO_2-equivalent using a 100-year GWP of 25 for methane.



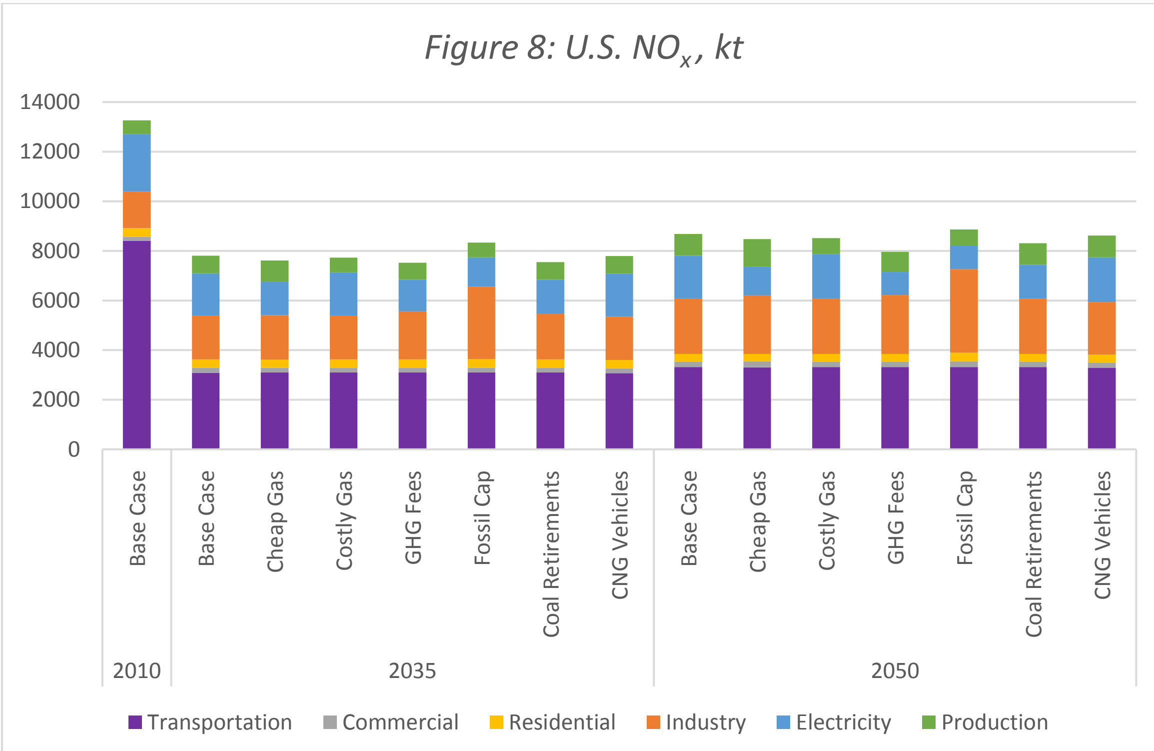
The small short term decrease in emissions is primarily a result of electric sector CO_2 emission reductions as well as transportation sector CO_2 emission reductions due to higher vehicle efficiency requirements (NHTSA 2014). In Cheap Gas, a GHG emission reduction from electric sector fuel switching offsets an increase in methane emissions due to rising NG production. Additionally, in Costly Gas, reductions in methane emissions from oil and gas production as a result of the U.S. EPA's NSPS/NESHAP rules taking effect in 2015 as well as slow growth in NG production contribute a small share of the GHG savings. In the long term, the earlier reduction in GHG emissions is negated in the base case and Cheap Gas. Emissions rebound in Costly Gas as well, but to a lesser extent, leaving 2050 emissions lower than 2010 levels. The GHG increases in this time frame are primarily a result of industrial and transportation sector CO2 emissions, although significant growth in methane emissions from rising NG production in the base case and Cheap Gas also makes a contribution. When the 20-year GWP of 72 for methane is used instead of the 100-year GWP, the GHG emission increase from 2010-2050 in Cheap Gas doubles from 3% to 6%. In Costly Gas, the GHG emissions increase from 2035-2050 is smaller because additional electricity demand is met with wind instead of NG, and growth in methane emissions is much smaller.

U.S. VOC emissions are dominated by emissions from the transportation sector, which decrease steadily in the base case as well as both NG supply scenarios from 2010 to 2050. The decrease is a result of more stringent standards for VOC emissions from new motor vehicles. The variation in VOC emissions between the base case, Costly Gas, and Cheap Gas is a result of emissions associated with natural gas production (Fig. 7). As the actual methane content of natural gas can vary between 70-95% on a molar basis, and hydrocarbons categorized as VOCs comprise much of the non-methane content of NG, VOC emissions occur when NG is leaked during NG production and processing before the dry NG is separated from its associated valuable condensate (Gilman 2013). Thus, despite steadily decreasing transportation sector VOC emissions in each scenario, VOC emissions from NG production result in small relative increases in total emissions in the base case and Cheap Gas scenarios in the long term from 2035-2050. Although the net effect is preserved – VOC reductions from 2010-2050 in each scenario – the reduction is significantly dampened in Cheap Gas. Costly Gas sees the greatest overall reduction in VOC emissions, as growth in NG production in this scenario is relatively slow.



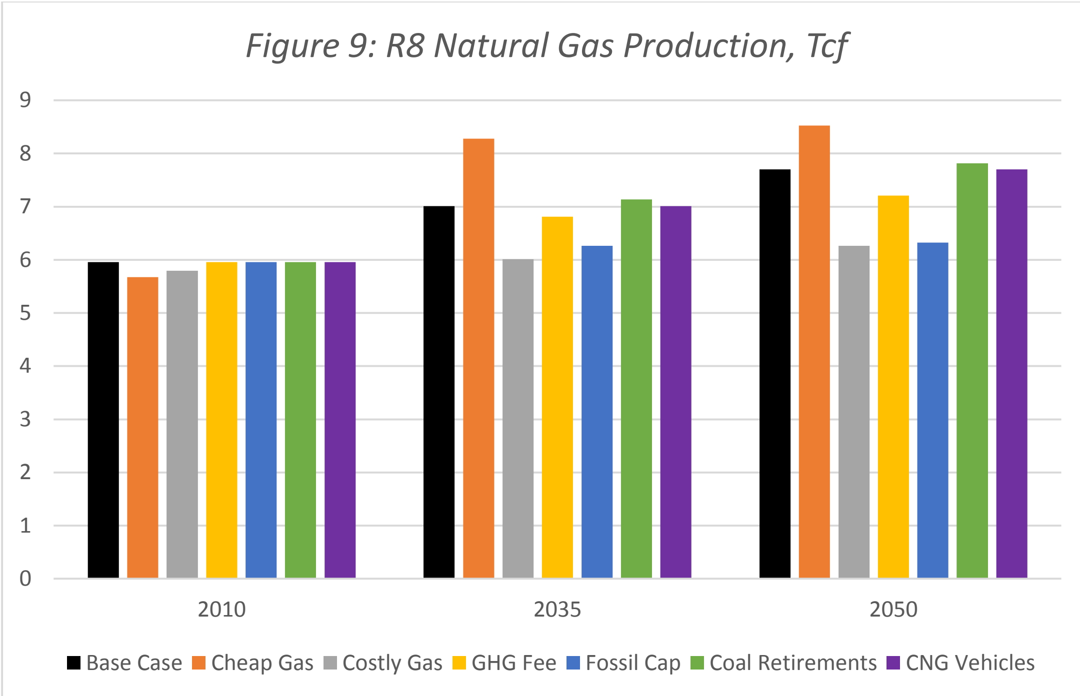
While the magnitude of VOC emissions associated with oil and gas extraction activities depicted in these scenarios is nontrivial, it should be noted that the light alkanes emitted during such activities are not as reactive, in general, as VOCs including alkenes and aromatic compounds that are emitted from motor vehicles (Carter 1994). Thus, oil and gas-associated VOC emissions may not produce as much tropospheric ozone as an equivalent mass of emissions from the transportation sector.

U.S. NO_x emissions, dominated by the electric, industrial and transportation sectors in each scenario, do not vary appreciably between the NG supply scenarios, remaining close to base case levels from 2010-2050 (Fig. 8). The trend in NO_x emissions is characterized primarily by a sustained, substantial reduction in vehicle emissions in the short term, followed by a slight increase due primarily to growth in industrial sector emissions. Both Cheap Gas and Costly Gas feature slightly lower NO_x emissions than the base case from 2010-2050. In Cheap Gas, the reduction is due to more extensive fuel switching in the electric sector, which would have a larger effect on emissions if not for a concurrent increase in NO_x from NG production activities; in Costly Gas, it is due to lower emissions from oil and gas production.

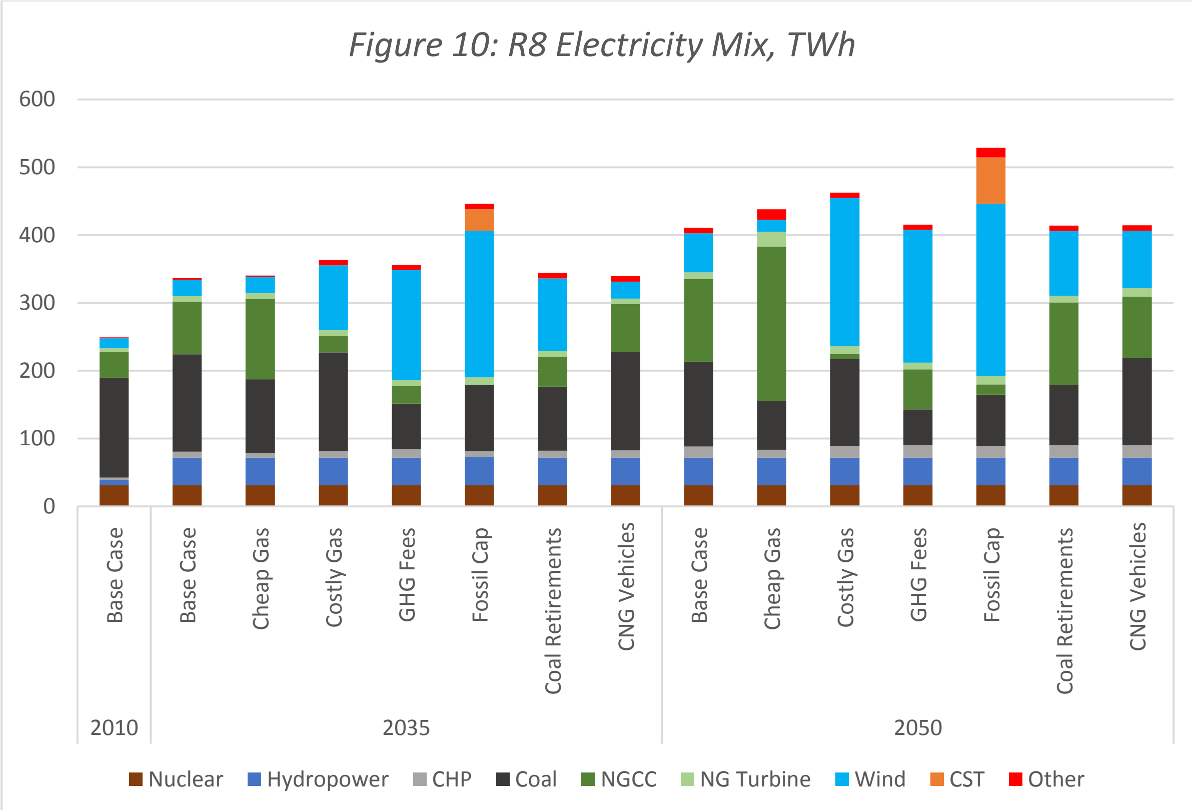


IIIa.ii Rocky Mountain Region

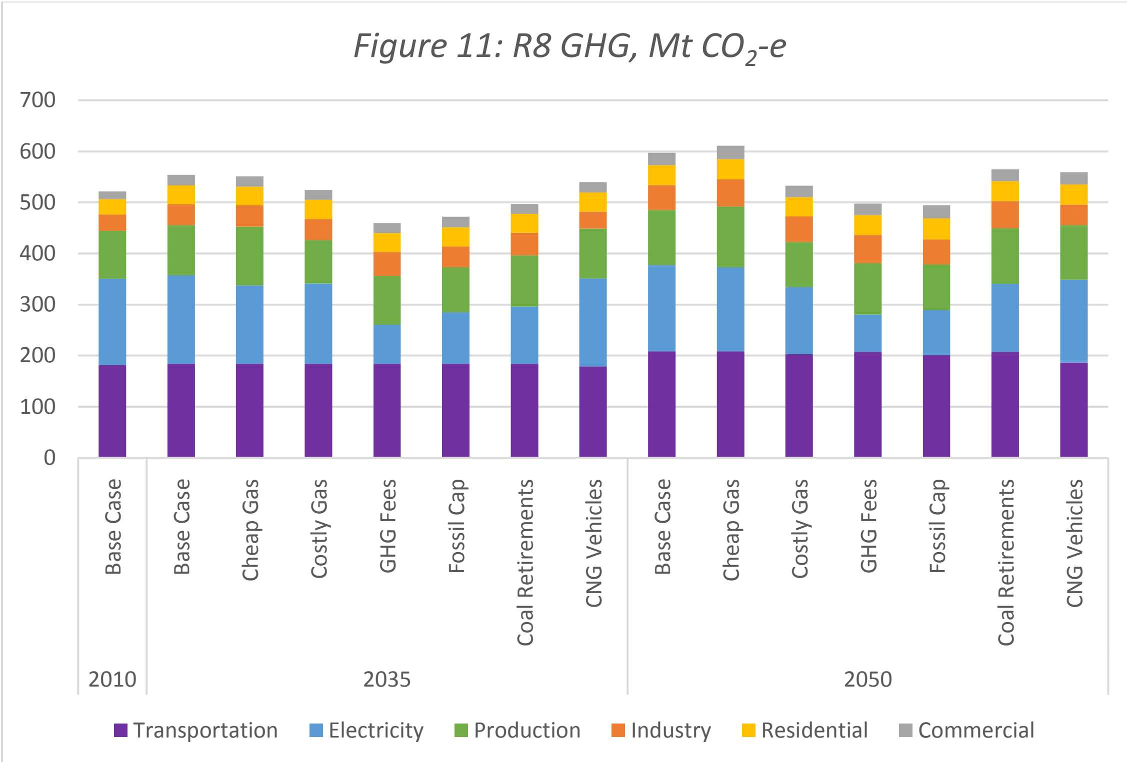
NG production in R8 follows the same general trends for the base case, Cheap Gas and Costly Gas as in the national results, but with increases of smaller magnitude: from 2010-2050, the regional growth rates in each scenario are less than half of the corresponding growth rates in the national results (Fig. 9). In Costly Gas, after a small short term increase NG production changes very little until 2040.



In the R8 electricity generation mix, the same trends are observed as in the national results, with small differences in the results for the base case and Costly Gas (Fig. 10). Wind is more prevalent in the Rocky Mountain region in these two scenarios than in the U.S. as a whole. In Costly Gas, electricity from NG is not competitive with wind even in the short term, and as wind continues to penetrate into the mix in the long term, reaching 50% of generation in 2050, NG electricity falls to below 5% of the generation mix. There is no fuel switching from coal to NG in Costly Gas in R8; rather, coal electricity generation decreases very little, as it continues to be needed for meeting baseload demand with increasing levels of wind in the generation mix.



Unlike in the national results, GHG emissions for the base case, Cheap Gas and Costly Gas in R8 increase consistently throughout the modeling time frame (Fig. 11). An exception is found when using the 20-year GWP of 72 for methane in Costly Gas: this causes overall carbon emissions in Mtonne CO_2-equivalent to rise in 2010, when the EPA rules addressing methane leakage have not taken effect yet, so that the short term trend in GHG emissions is actually a net decrease with emissions eventually rebounding back to 2010 levels in 2050. Thus, in Costly Gas, the GWP used for methane illustrates the regional importance of methane emissions from NG production activities.

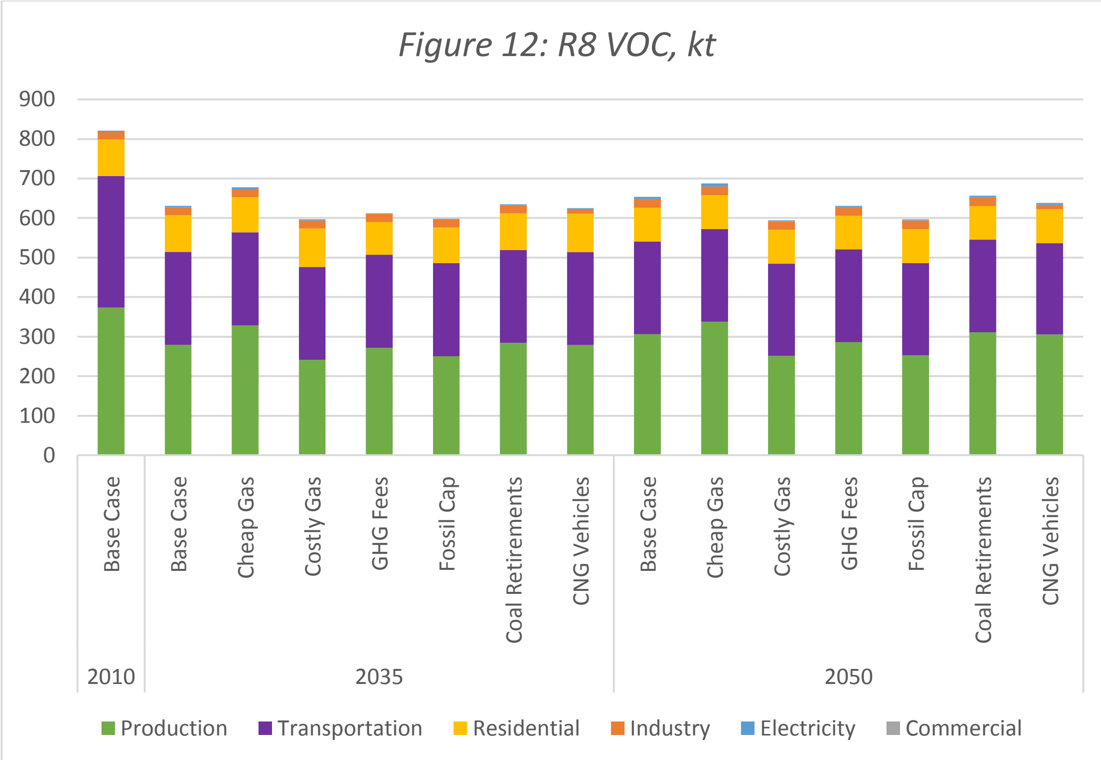


Costly Gas also retains the GHG emission advantage throughout the modeling time frame; steady increases in regional GHG emissions in each scenario are driven by CO_2 emissions from the industrial and transportation sectors, as in the national results, but in R8 methane emissions from NG production play a proportionally larger role in the base case and Cheap Gas, whereas in Costly Gas these emissions decrease significantly from 2010 levels. The much smaller GHG contribution from regional oil and gas production activities in Costly Gas, along with electricity demand being primarily met with wind instead of NG as in the national results, result in this scenario keeping carbon emissions in check through 2050. The same cannot be said for Cheap Gas, in which regional carbon emissions remain below the base case for the short term as a result of fuel switching in the electric sector, but overtake base case emissions by 2050 due to expanded use of NG in place of wind in the electric sector in addition to contributions from

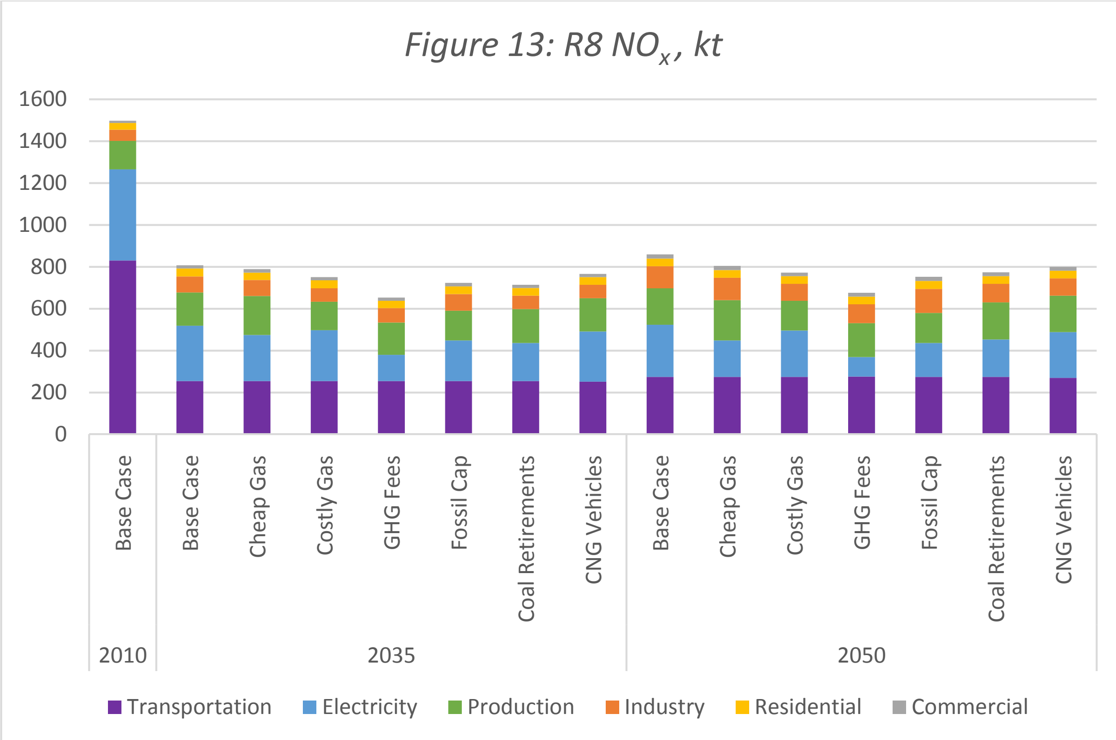
NG production-related methane emissions and industrial sector use of LPG and NG in place of biomass.

The importance of methane emissions from NG production in R8 in the Cheap Gas scenario becomes apparent when compared to the corresponding national-scale result. In Cheap Gas in 2035, methane emissions from fossil fuel extraction activities comprise 5% of total nation-wide GHG emissions on a Mtonne CO_2-e basis when using a GWP of 25 for methane; when using a GWP of 72 for methane, the contribution rises to 14%. In the Rocky Mountain region, the contribution from fossil fuel production-related methane emissions is 12% using a GWP of 25 and 27% using a GWP of 72. The implication is that in this scenario, even with EPA rules reducing methane emissions from NG production activities, these emissions contribute more to regional GHG emissions in 2035 than the electric or transportation sectors if a 20-yr GWP is used for methane.

In the NG supply scenarios, VOC emissions decrease in the short term due in large part to a significant reduction in transportation sector emissions, but also due to the effects of the EPA's NSPS and NESHAP rules (Fig. 12). In the long term, emissions begin to creep back up due to the increasing contribution from oil and gas production. Regional VOC emissions in Cheap Gas remain above the base case for the modeling time frame due to the added contribution from increased levels of NG production. Again, however, VOCs emitted by oil and gas extraction activities differ from those emitted by transportation sector sources, so overall VOC emissions being driven back up to these levels by sources in the former category may not have the same implications for air quality.



NOx emissions in R8 decrease by close to 50% below 2010 levels in all three scenarios by 2035 due to stricter controls on power plant and tailpipe emissions, the two categories responsible for the majority of NOx emissions in the energy system (Fig. 13). As in the national results, small long-term increases in regional NO_x emissions (2035-2050) are due primarily to the industrial sector. Cheap Gas and Costly Gas NO_x emissions are lower than base case emissions throughout the modeling time frame, for the same reasons as in the national results.



IIIb. Low carbon scenarios: Fossil Cap, GHG Fees, and Coal Retirements

IIIb.i National Results

In GHG Fees and Coal Retirements, NG production remains close to base case levels throughout the modeling time frame, with production in GHG Fees only slightly lower in the long term due to less use of NG throughout the energy system, and production in Coal Retirements slightly higher because of more NG use in the electric sector (Fig. 4). NG Production in Fossil Cap is significantly lower than in the base case, very close to levels in Costly Gas, due to decreasing use of NG in the electric sector.

The electricity mix results for the low carbon scenarios exhibit the sensitivity of electric sector NG use to the effects of simplified policies that address the range of electric generating technologies available to MARKAL (Fig. 5). In Coal Retirements, comparatively high electric sector NG use throughout the modeling time frame as well as little additional wind when compared to the base case illustrates that NG is the preferred fuel for replacing coal in the electric sector under an otherwise business-as-usual set of assumptions. The steadily increasing levels of electric sector NG use in GHG Fees imply that the Social Cost of Carbon estimates used in this scenario are not high enough to significantly deter the transition to NG as a primary source of electricity – electricity produced by NG combined cycle plants in this scenario is close to base case levels in the short and long terms. The preferred sources of electricity used for meeting additional demand from 2010-2050 in Fossil Cap are CST, wind and solar PV, with CST helping to replace coal as a means of meeting baseload demand.

In each low carbon scenario, GHG emissions in 2050 are lower than 2010 levels and lower than base case levels in the same year (Fig. 6). In the short term from 2010-2035, all four scenarios (base case and low carbon scenarios) feature GHG emission reductions due largely to fuel switching away from coal in the electric sector as well as, to a lesser extent, more fuel-efficient vehicles. The comparatively high electric sector NG use featured in Coal Retirements provides a reduction in GHG emissions from base case levels in the short term but this benefit erodes further down the road as additional electricity demand is met with mostly NG. In GHG Fees, electric sector carbon emissions decrease throughout the modeling time frame even as NG electricity production continues to rise, because there is less coal electricity in later years in addition to a greater contribution from wind. Importantly, the “carbon costs” imposed in this scenario result in nationwide GHG emissions that are 10% below 2010 levels in 2050, but do not have a large effect on use of NG in the electric sector nor continued gasoline use in the transportation sector. The implication is that mid-range estimates for the social cost of carbon – up to $76/tonne CO_2-equivalent in 2050 (2011 dollars) – that affect both CO_2 emissions from power plants and methane emissions from NG extraction do not make NG appreciably less competitive in meeting demand for energy services, nor do they succeed in lowering overall U.S. carbon emissions by more than 15% below 2010 levels.

Fossil Cap consistently features the lowest carbon emissions among the scenarios, with the lowest emission modeled year being 2035 at 19% below 2010 levels. This modest GHG emission reduction, well below the cuts suggested by the International Panel on Climate Change in order to avert the worst impacts of climate change, demonstrates the limited effectiveness of a carbon reduction strategy based solely on policies affecting the electric sector (Guardian 2014).

Variation in U.S. VOC emissions among the low carbon scenarios and the base case is generally not appreciable, with the exception of Fossil Cap which features lower emissions due to slow growth in NG production.

In the short term, U.S. NO_x emissions in the low carbon scenarios closely trace the base case with little variation, with the exception of slightly higher emissions in Fossil Cap, where NO_x emissions remain higher than base case levels throughout the modeling time frame (Fig. 8). The reason is that Fossil Cap features constraints on fossil fuel use in the electric sector, but none for the industrial sector, which is a contributor of NO_x emissions on roughly the same scale. Thus, the NG that is used in new combined-cycle NG plants to generate electricity in the base case is used in the Fossil Cap scenario in industrial processes such as CHP. As NO_x emissions rates (per unit heat input) are generally higher in the industrial sector in MARKAL than in the electric sector, the result is increased overall NO_x emissions in Fossil Cap. In the long term, small increases in NO_x emissions in each scenario may be attributed to increasing fossil fuel use in the industrial and transportation sectors.

IIIb.ii Rocky Mountain Region

In the low carbon scenarios, NG production in the Rocky Mountain region generally follows the same trends exhibited in the national results, with some differences in the explanations behind those trends. Just as in the U.S. as a whole, regional NG production in Fossil Cap remains below that in the base case through 2050, but as opposed to the national results where NG production continues to grow through 2050, NG production in R8 remains almost constant after 2020 (Fig. 9). This is due to the very small amount of NG in the R8 electricity mix as well as insignificant long term growth in industrial sector NG use. NG production in Coal Retirements remains slightly higher than base case levels from 2010-2050; however, in the regional case this is not due to more use of NG in the electric sector. R8 NG production in Coal Retirements is higher than in the base case even in years where total in-region energy system use of NG is significantly lower. In this scenario, the Rocky Mountain region remains a large producer of NG due to increasing exports to neighboring regions where NG demand is sustained: R4 (West North Central) in the short term, and R7 (West South Central) in the long term.

The R8 electricity mix exhibits reduced coal in each low carbon scenario, as in the national results, as well as a greater prevalence of wind in the short term (Fig. 10). In GHG Fees, most coal electricity that exits the mix in the short term is replaced with wind, as opposed to NG in the national results. This suggests that the price margin between NG and wind electricity in R8 is narrow, as fees imposed during the time period when wind begins to enter the mix, 2030-2035, are still relatively low. GHG Fees also shows the greatest short term reduction in fossil fuel electricity among the low carbon scenarios. In later years, with additional coal retirements and wind having almost reached its maximum penetration into the electricity mix of 50%, more NG enters the mix in order to meet baseload demand. Fossil Cap also features extensive early penetration of wind into the R8 electricity mix as well as more electricity generation overall. In this scenario, instead of reducing coal electricity as much as in GHG Fees, MARKAL chose to instead reduce NG electricity while significantly increasing the total electricity generated in the region in order to satisfy the constraint on fossil fuel electricity generation as a fraction of total electricity generation. The extra electricity generated in region 8 is mostly exported to region 9, the west coast. In the long term, baseload electricity demand is met with a small increase in NG generation, as in GHG Fees, but the main source is CST, for which the most economically effective and abundant resource has been demonstrated to exist in R8 states including Nevada and Arizona where the desert sun provides ample direct insolation. Both wind and NG play important roles in Coal Retirements, but unlike in the national results, wind is the preferred source of electricity for replacing the regional coal retirements that take place in this scenario in addition to those already present in the base case. These additional coal retirements are small: only 7 of 100 GW of coal-fired electric capacity retired in the U.S. from 2010-2050 is retired in the Rocky Mountain region in this scenario.

The trend in GHG emissions in the Rocky Mountain region is a slightly different story from the base case; although all three low carbon scenarios feature lower overall emissions than the base case, GHG Fees has the lowest carbon emissions in the short term due to electric sector trends influenced by MARKAL’s method of satisfying the constraint in Fossil Cap as described above (Fig. 11). After small reductions, GHG emissions in each of the three low carbon scenarios increase from 2035 to 2050 due to increasing electric sector NG use, with emissions in Coal Retirements exceeding 2010 levels in 2050. Despite comparatively low overall fossil fuel use in Fossil Cap and GHG Fees, overall GHG emission reductions in these scenarios are never more than 15% below 2010 levels throughout the modeling time frame.

Trends in Region 8 VOC emissions among the low carbon scenarios are similar to those for the U.S. as a whole; reductions from the base case mainly take place in Fossil Cap as a result of NG production trends described above (Fig. 12). The role of VOC emissions associated with oil and gas production is slightly amplified in Coal Retirements.

In the Rocky Mountain Region, emissions of NO_x generally display the same trends as those observed on the national scale, and for the same reasons. All three low carbon scenarios feature greater emissions reductions than in the base case, mostly due to less use of coal in the electric sector over time (Fig. 13). Differences in NO_x emissions among the low carbon scenarios can mostly be attributed to the industrial and electric sectors, where GHG Fees features the lowest emissions in the long term and results in the greatest reduction in regional emissions. Finally, percentage NO_x reductions in the Rocky Mountain region from 2010-2050 are higher than on the national scale in each scenario, because proportional use of coal in the electric sector is higher in this region than in the U.S. as a whole – and electric sector coal use is one of the primary sources of NO_x emissions.

IIIc. CNG Vehicles Scenario

With the recent rise of relatively cheap and abundant natural gas in the U.S., attention has been given to the possibility of NG serving as an alternative to conventional gasoline or diesel in certain sections of the transportation sector. Natural gas vehicles, including those fueled by compressed natural gas (CNG) and liquefied natural gas (LNG), appear to have the most potential for adoption in the heavy duty vehicle (HDV) section of the transportation fleet, as well as in centrally-fueled vehicle fleets which may include both light-duty vehicles (LDV) and HDVs (MIT 2011). These segments of the transportation sector already contain the highest numbers of CNG and LNG vehicles, and have potential for expansion of this market: HDVs primarily use diesel fuel, with which CNG is already cost-competitive on an energy-equivalent basis (MIT 2011). Fleet vehicles that refuel at a central location do not face the problem of a distributed NG vehicle refueling infrastructure potentially lagging behind increasing adoption of NG vehicles. Additionally, CNG vehicle adoption in the short term will depend on the payback period of the vehicle investment. Vehicle categories with short CNG vehicle payback periods include heavy duty short-haul trucks and buses, due to their exceptionally low fuel economy, and light duty fleet vehicles due to their relatively high-mileage operation (MIT 2011).

As described in the Methods section, the CNG Vehicles scenario features increased penetration of CNG-fueled vehicles into the aforementioned categories: heavy duty short-haul trucks, buses, and light duty fleet vehicles.

IIIc.i National Results

The considerable restructuring of the fuel supply for HDVs and light duty fleet vehicles featured in the CNG Vehicles scenario yields a modest 2% increase in U.S. NG production over the base case in 2050 (Fig. 4). A significant amount of the NG needed to meet additional transportation sector demand in CNG Vehicles is diverted from the electric and industrial sectors, where the fuel supply is slightly restructured. In the CNG Vehicles scenario, the transportation sector accounts for 14% of NG use in 2050, whereas in the base case it accounts for 1%.

The national electricity mix in CNG Vehicles features more wind and less NG in the long term, making more NG available for fueling increasing numbers of CNG trucks, buses and cars without significantly increasing production.

U.S. GHG Emissions from 2010-2050 are slightly lower in CNG Vehicles when compared with the base case (Fig. 6). The primary driver of this reduction is CNG use replacing some diesel use in the transportation sector prior to 2035, and later becoming the preferred fuel to meet additional transportation sector energy demand over gasoline and diesel. In 2050 the GHG emissions in CNG Vehicles are only slightly lower than in the base case, but this reduction is enough to keep emissions just barely below 2010 levels when using a GWP of 25 for methane. When using the 20-year GWP of 72 for methane, the GHG emission reduction from 2010 in CNG Vehicles vanishes. Notably, methane emissions from additional NG production and the increased numbers of CNG vehicles on the roads in this scenario barely contribute to total GHG emissions on a CO_2-equivalent basis. U.S. NG production in CNG Vehicles increases by 64% from 2010-2050 compared with 61% in the base case, resulting in only slightly more than a 3 Mtonne increase in carbon emissions in 2050; transportation sector methane emissions in 2050 in CNG Vehicles are about 10 kilotonnes higher than in the base case, but this has no appreciable effect on overall GHG emissions.

U.S. VOC emissions in CNG Vehicles are nearly equal to those in the base case from 2010-2050. Transportation sector VOC emissions are only slightly smaller in CNG Vehicles when compared to the base case, due to CNG buses emitting less VOC than diesel buses (Fig. 7).

U.S. NO_x emissions in CNG Vehicles do not vary appreciably from those in the base case through 2050, following the same trends throughout the modeling time frame. Post-2035, industrial sector NO_x emissions in CNG Vehicles are slightly lower than in the base case because of lower NG use in this sector (Fig. 8). During this time frame, a small portion of industrial sector fuel use switches from NG in the base case to biomass in the CNG vehicles case.

IIIc.ii Rocky Mountain Region

Results for NG production, electricity mix, and emissions in CNG Vehicles differed less from the corresponding base case results in R8 than for the U.S. as a whole. This is because the national-scale requirement for CNG vehicle penetration into LDV fleets was mostly met with deployment of CNG vehicles in regions 3 (Great Lakes), 7 (Texas and West Gulf), and 9 (Pacific and Alaska), regions where the modeling assumptions for the combined cost of extracting NG and delivering it to transportation sector end uses were lowest. For the results, this is the case until 2050, when CNG vehicles in other regions start contributing their share to the lower bound on vehicle miles traveled. A more detailed description of the modeling constraints relevant to this scenario is available in the Supporting Information.

NG production in the Rocky Mountain region in CNG Vehicles is equal to base case levels from 2010-2050 (Fig. 9). Some of the additional NG needed in R8 to meet transportation sector CNG demand in CNG Vehicles is diverted from other sectors, imported from Region 4 (Midwest), and diverted from exports to Mexico when compared to the base case.

In the regional electricity mix, there is a larger presence of wind in CNG Vehicles in later years when compared with the base case, due to NG being diverted from the electric sector to the transportation sector.

The regional GHG emission trend in CNG Vehicles when compared with the base case is similar to the national results: lower emissions through 2035 from the industrial and transportation sectors, with the deficit becoming more pronounced in 2050 due to the larger presence of wind in the CNG Vehicles electricity mix (Fig. 11). The regional difference in GHG emissions from the base case from 2010-2050 in CNG Vehicles is larger on a percentage basis than the corresponding national trend.

Region 8 VOC emissions in CNG Vehicles are nearly the same as in the base case. There is a very small decrease, for the same reasons as noted in the national results.

In R8, there is a slightly larger difference in NO_x emissions between CNG Vehicles and the base case than there is in the national results (Fig. 13). CNG Vehicles features lower NO_x emissions from the electric, industrial, and transportation sectors. The difference in the electric and industrial sectors may be attributed to less NG use in these sectors, and the very slight reduction in transportation sector NO_x emissions in CNG Vehicles is due to heavy-duty short haul trucks switching from diesel to CNG over time.

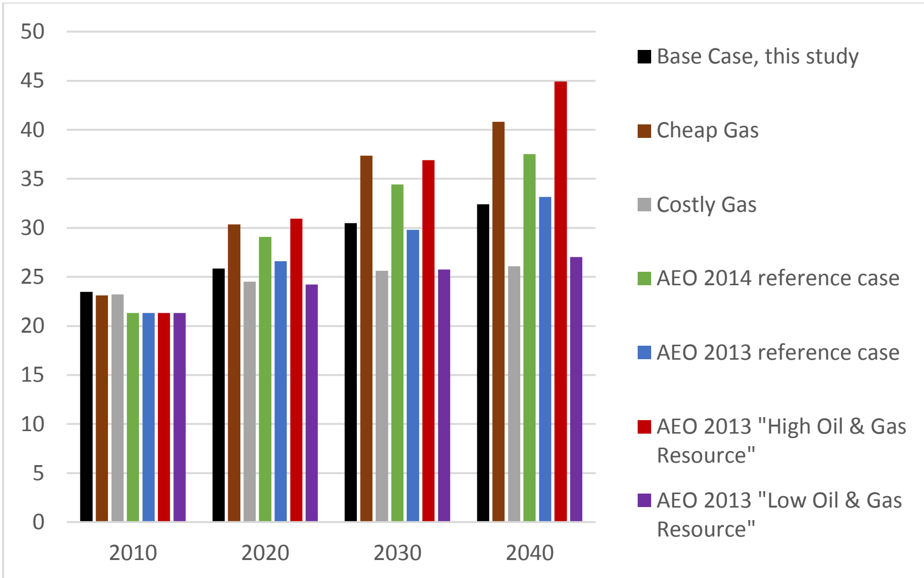
IV. Conclusions

This study developed scenarios to examine the potential effects of future policies affecting natural gas use in the energy system as well as contrasting trends in NG market characteristics. These scenarios were incorporated into the MARKAL least-cost energy system optimization model and the EPAUS9r database to examine their future emissions implications. It should be stressed that the MARKAL modeling results are not predictions, but characterizations of the relationships between simultaneous influences on the energy system in the future and of the potential effects that future energy or environmental policies could have. In addition, any conclusions drawn from the results must account for the limitations of the MARKAL model. For one, it is a demand-explicit linear optimization model, which means that the full elasticity of supply and demand is not accounted for in the model solutions. Also, the model has limited representation of technologies that increase the efficiency of energy generation, transmission, storage and consumption processes as well as limited options for improving the efficiency of existing technologies. Gains in efficiency will likely be a prominent driver of progress on the most complex and critical current energy problems, and while MARKAL is able to satisfy demand for energy services with more efficient technologies in some areas, it does not have a full representation of the spectrum of energy efficiency services and technologies in use today. Furthermore, the modeling results presented in this study naturally depend on the modeling assumptions. Extensive research went into developing a reasonable set of assumptions for technology characteristics and emissions factors, for example, but some assumptions are at best engineering estimates and the conclusions should be read keeping this in mind. The value of future modeling work in assessing the emissions implications of natural gas production and use will benefit from the knowledge gleaned from the results of direct measurement studies being performed in recent years (e.g. Allen et al. 2013) and in the future. Avenues for future research in this area should focus on improving the quality of modeling assumptions as much as possible.

IVa. National

U.S. NG production continues increasing through 2050 in each scenario modeled in this study, with the largest growth occurring in Cheap Gas, especially in the short term. The base case, Coal Retirements and CNG Vehicles feature similar NG production trends on the national scale, slightly over 60% increases from 2010-2050. Modest growth in NG production also occurs even when supply is constrained in Costly Gas and renewable technologies begin to edge NG out of the electricity mix in Fossil Cap. NG production trends projected in this study are within the range of estimates released by EIA in its 2013 and 2014 AEO projections to 2040 (Fig. 14), which include two scenarios with assumptions similar to those in Cheap Gas and Costly Gas (EIA 2013, EIA 2014).

Figure 14: U.S. Natural Gas Production Comparison, Tcf



Modeling results in the two scenarios featuring variations in future NG supply assumptions, Cheap Gas and Costly Gas, illustrate the sensitivity of NG use to wellhead costs and allow for comparisons of emission trends in potential future U.S. energy systems featuring varying levels of NG use. Electricity mix results for these scenarios indicate that over the range of NG wellhead costs modeled, fuel switching in the electric sector from coal to NG continues to take place through 2035, demonstrating that NG is the preferred fuel for replacing coal for electricity generation in the short term. The competition between wind and NG in Costly Gas indicates that NG is preferred over wind for meeting additional electricity demand until roughly double its current delivered cost to the electric sector. The GHG emission results for the supply scenarios indicate that in a future with cheap and abundant NG as depicted in the Cheap Gas scenario, small short term GHG reductions are possible, but with continually increasing use of NG in the industrial sector and steadily increasing emissions of methane associated with NG production, U.S. GHG emissions will eventually rebound back to 2010 levels. To a somewhat lesser extent, a similar implication applies to VOC emissions in the long term: in the long term in the Cheap Gas scenario, oil and gas production-related VOC emissions begin to reverse the downward trend in overall emissions observed due to large short term transportation sector reductions driven by CAFE and vehicle emissions standards. However, as noted in the Results section, elevated levels of VOC emissions from the upstream oil and gas sector may not have the same air quality impacts as those from the transportation sector. Finally, emissions of NO_x in the Cheap Gas scenario highlight the importance of NG production-related NO_x, especially in the long term – cheap, abundant NG results in this sector contributing emissions on the same scale as those from the electric sector, offsetting long term benefits from retirements of coal-fired power plants.

Results for the Fossil Cap, GHG Fees, and Coal Retirements scenarios allow comparison of the effectiveness of three electric sector GHG reduction strategies, and demonstrate how emission trends are affected by future levels of NG use in electric power generation and other processes in the U.S. energy system. The future electricity mix depicted in the Coal Retirements scenario suggests that NG combined cycle (NGCC) plants are the preferred source of electricity production for replacing existing coal plants as well as meeting additional demand in the long term under an otherwise business as usual set of assumptions. Also, just as in Cheap Gas, the short term fuel switching from coal to NG in Coal Retirements results in a reduction in electric sector GHG emissions (reaching ~33% below 2010 levels in 2025), but as electricity from NG continues to increase in later years, the GHG reduction disappears. Once again, this illustrates the importance of treating NG electricity as a bridge to renewables if the goal is to continue cutting GHG emissions. Another significant result comes from the electricity mix in GHG Fees:

in this scenario, there is less electricity generation from coal and NG than in the base case, as well as more from wind, but coal electricity is affected by the carbon fees much more so than NG. The implication is that NG is a cost-effective fuel for electric power generation even with mid-range estimates for the social cost of carbon adding cost penalties for methane emissions from upstream NG processes as well as CO_2 emissions from NGCC plants. With a carbon tax of \$60/tonne CO_2-equivalent (2005 dollars) applied to emissions in 2050, electricity from NG in the GHG Fees scenario is only 12.5% below the base case. The continued electricity generation from NG depicted in GHG Fees reduces the effectiveness of the fees in lowering U.S. GHG emissions – emissions in Fossil Cap are lower throughout the modeling time frame – but even in Fossil Cap, the maximum GHG reduction is only 18.5% below 2010 levels. This demonstrates the limited overall effectiveness of a GHG emission reduction strategy that solely targets the electricity sector. Additionally, with more aggressive fees applied to GHG emissions across the energy system, the U.S. could achieve higher emission reductions – a hint at this effect is implied in the GHG Fees scenario, where a maximum GHG emissions reduction close to that in Fossil Cap is achieved due to electric sector fuel switching from coal to gas and greater penetration of wind than in the base case. Finally, the comparatively high long term NO_x emissions in the Fossil Cap scenario imply that NG use in industrial processes is a potentially important source of NO_x.

The last scenario modeled in this study, CNG Vehicles, did not produce significantly altered emissions trends when compared with the base case, implying that the levels of CNG vehicle penetration depicted in this scenario would not be enough to significantly affect nationwide emissions of GHGs, VOC or NO_x. The reduction in transportation sector GHG emissions implied by a fleet of 100% CNG buses, heavy duty short-haul trucks, and fleet vehicles is just over 100 Mtonne below base case levels in 2050, about a 2% overall reduction.

IVb. Rocky Mountain Region

Trends depicted in each scenario for NG production in the Rocky Mountain region in this study are generally aligned with those in the national results. The Coal Retirements scenario illustrates the importance of the region as an exporter of NG when retirements of coal-fired power plants accelerate in neighboring regions.

MARKAL's solutions for the electricity generation mix through 2050 in the Rocky Mountain region show that in scenarios where NG is more expensive in the short term (Costly Gas and GHG Fees), wind becomes an important source of electricity. This suggests that the cost margin between NG and wind in the electric sector in this region is smaller than in the U.S. as a whole. In addition, the Coal Retirements scenario illustrates that wind and NG can serve interchangeably as replacements for retired coal generation in this region to the extent that wind capacity is available to meet peak demand. The Fossil Cap scenario also illustrates the importance of CST as a viable renewable technology in the Rocky Mountain region when electricity from fossil fuels is constrained.

In the Rocky Mountain region, NG production-related methane emissions contribute proportionally more to regional GHG emissions than on the national scale, due to the scale of NG production taking place in this region as well as the assumption that most of it will continue to come from conventional gas reserves rather than shale gas reserves, reducing the effect of the EPA NSPS and NESHAP rules. The results of this study suggest that in a future where NG is cheap and abundant and production grows steeply, as depicted in the Cheap Gas scenario, oil and gas production-related methane may become a source of GHG emissions rivaling contributions from the electric and transportation sectors in the long term if a 20-year global warming potential is used.

In summary, the results of this study suggest that NG will continue to play an important role in meeting energy demand both in the U.S. and Rocky Mountain region, especially in the electric and industrial sectors. Its use in the electric sector provides an opportunity to reduce GHG emissions in the short term, but continued use in the long term without also integrating renewables like wind into the grid risks losing its GHG benefit. Expanded production of NG also implies that emissions of VOC and NO_x associated with its extraction will begin to contribute to rising overall emissions of these pollutants in the long term, and emissions of NO_x from industrial processes burning NG are nontrivial. Results from the range of scenarios modeled indicate that unless NG production continues to increase at a rate similar to that depicted in Cheap Gas, associated methane leakage will not significantly affect the carbon reduction opportunity that its short term use in the electric sector presents. As mentioned above, future modeling work will benefit from improved quality of modeling assumptions that leverage the results of measurement studies. Wider ranges of scenarios focused on isolating the effects of single market and policy drivers in the energy system may also help reveal more specific sensitivities; thus, there is an opportunity for future research along those lines.

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