Published in final edited form as:
Energy Econ. 2016 ; 60: 460–468. doi:10.1016/j.eneco.2016.06.009.

Role of natural gas in meeting an electric sector emissions reduction strategy and effects on greenhouse gas emissions

Carol Lenox, **P. Ozge Kaplan**
National Risk Management Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711, USA

Abstract

With advances in natural gas extraction technologies, there is an increase in the availability of domestic natural gas, and natural gas is gaining a larger share of use as a fuel in electricity production. At the power plant, natural gas is a cleaner burning fuel than coal, but uncertainties exist in the amount of methane leakage occurring upstream in the extraction and production of natural gas. At higher leakage levels, the additional methane emissions could offset the carbon dioxide emissions reduction benefit of switching from coal to natural gas. This analysis uses the MARKAL linear optimization model to compare the carbon emissions profiles and system-wide global warming potential of the U.S. energy system over a series of model runs in which the power sector is required to meet a specific carbon dioxide reduction target across a number of scenarios in which the availability of natural gas changes. Scenarios are run with carbon dioxide emissions and a range of upstream methane emission leakage rates from natural gas production along with upstream methane and carbon dioxide emissions associated with production of coal and oil. While the system carbon dioxide emissions are reduced in most scenarios, total carbon dioxide equivalent emissions show an increase in scenarios in which natural gas prices remain low and, simultaneously, methane emissions from natural gas production are higher.

Keywords

Energy system; Scenario analysis; Carbon emissions reductions; Methane; Natural gas

1. Introduction

Due to recent advances in extraction technologies that give greater access to gas stored in tight formations such as shale, natural gas production and use is on the rise in the United States. Greater availability of domestic natural gas has led to decreases in price, making natural gas more attractive to companies and individuals across the U.S. energy system. The U.S Energy Information Administration's (EIA), 2014 Annual Energy Outlook (AEO2014) highlights that the use of natural gas in power production and end-use sectors increased 8%

Disclaimer
The views expressed in this article are those of the authors and do not necessarily represent the views or policies of the U.S. Environmental Protection Agency.

between 2000 and 2014. The use of natural gas is projected to grow another 25% between 2014 and 2040 (U.S. EIA, 2014). The power sector is the largest user of natural gas. The AEO2014 projects that 33% of the increase in natural gas consumption out to 2040 will occur in the power sector, with new natural gas power plants replacing older retiring coal-fired generation power plants, and that the share of electricity generation by natural gas will rise from 26% to 35% by 2040 (U.S. EIA, 2014).

As natural gas becomes more readily available domestically, it is important to understand if there is an overall greenhouse gas (GHG) emissions benefit in moving from coal to natural gas in the power sector. While natural gas burns cleaner than coal, there is considerable variability in estimated upstream emissions from the extraction, processing, transmission, and distribution of natural gas. Natural gas is composed primarily of methane (CH_4), which is a much more potent GHG than carbon dioxide (CO_2), and this methane can be released into the atmosphere during upstream processes. These fugitive emissions include routine venting and unintended emissions at the well, at the processing plant, and during transmission and distribution.

The global warming potential (GWP) is an index of the radiative forcing of a particular gas relative to the same quantity of CO_2 over a specified period of time. The Intergovernmental Panel on Climate Change (IPCC) estimates the GWP of methane to be 28 over a 100-year time period, meaning that methane has a total warming impact that is 28 times greater than CO_2. Over a 20-year time period, the GWP of methane rises to 85 (Myhre et al., 2013). The higher level of GWP in the shorter time frame reflects the shorter life of methane in the atmosphere.

This study, which compares the carbon emissions profiles and system-wide global warming potential of the U.S. energy system over a series of model runs with a range of upstream methane emission leakage rates, was developed as part of the Energy Modeling Forum study #31 (EMF31): "North American Natural Gas and Energy Markets in Transition." The modeling groups in EMF31 explored a number of different issues surrounding the North American natural gas resource base including the effect of high and low natural gas resource availability and how changes in natural gas production impact emission reduction strategies in the power sector. The next section will discuss recent studies on the methane emissions from natural gas extraction, production, transmission, and distribution.

2. Background

There is a lot of research going on to address the wide-ranging estimates of the emissions occurring in well pads during the extraction, production and transmission of natural gas (Environmental Defense Fund, 2015). Emission inventories (e.g. EPA's greenhouse gas inventory) utilize bottom-up measurements and identify sources of methane pollution across the supply chain with the inclusion of hundreds of activities and equipment types along with extensive measurement data. Measurements of actual methane concentration in the atmosphere, also known as top-down studies, provide insights into the amount of emissions occurring over a region and includes methods to attribute these emissions to specific sources within the well pad. Both bottom-up and top-down methods are essential and need one another to enhance the emission factors used in planning activities.

A number of analyses have been performed on natural gas using various bottom-up or top-down measurements of methane to look at GHG emissions and to compare natural gas emissions with coal. All of the studies accounted for GHG emissions in terms of carbon dioxide equivalent (CO_2e). The carbon dioxide equivalent (CO_2e) is the standard metric for expressing different GHG emissions as a single number. The CO_2e expresses the amount of CO_2 that would cause the same radiative forcing over the specified period of time for a given mixture of GHGs. The CO_2e of a gas is calculated by multiplying the amount of gas emitted by the GWP value for that gas.

One question many of the studies attempt to answer is whether shale gas is any worse than conventional gas when emissions are accounted for across gas extraction, production, delivery, and use in power generation. Because combustion of natural gas is a larger source of total GHG emissions than natural gas upstream supply chain emissions, and combustion emissions are the same whether the gas comes from a conventional well or a shale well, most studies find shale gas to be only marginally higher than conventional gas when followed through to end use (Stephenson et al., 2011, Jiang et al., 2011, Hultman et al., 2011). Hultman et al. (2011) state that shale is "unlikely to be substantially more polluting than conventional gas." The National Renewable Energy Laboratory's (NREL) Joint Institute for Strategic Energy Analysis performed a meta-analysis with a number of reported analyses and concluded that the higher emissions from liquids unloading from conventional wells and the higher emissions from shale well completions balanced each other out, leading to similar emissions between the two (Heath et al., 2014).

When comparing the emissions of both conventional and shale gas to coal, most of these same studies find, along with others, that natural gas produces less GHGs than coal. The National Energy Technology Laboratory (NETL, 2011) performed a lifecycle analysis that found gas to emit as much as 50% fewer GHGs than coal, with an estimated range from 39% to 53%. An analysis by Venkatesh et al. (2011) found that using natural gas instead of coal as fuel to make electricity has close to a 100% chance of reducing emissions in the energy system.

An important assumption made for all of these studies is the estimated percent of methane emissions over the total amount of natural gas produced. This is known as the leakage rate. The NREL meta-analysis found that the studies which they analyzed used a wide range of leakage rates: 0.66% to 6.2% for unconventional wells and 0.53% to 4.7% for conventional wells (Heath et al., 2014). Weber and Clavin (2012) performed a Monte Carlo analysis that included many of the same studies as the NREL analysis and found a "best" estimate of methane leakage to be 2.7%. As Heath et al. (2014) point out, the variance in published leakage rates can come from different assumptions in the analyses including: inclusion or exclusion of specific extraction and production activities, modeling approaches, and system boundaries.

Several studies took their analysis a step further and estimated the leakage rate at which natural gas becomes worse than coal specifically in terms of GHG emissions. Jiang et al. (2011) did a direct comparison of natural gas and coal use at a specific point in time in the power sector and found that the methane leakage rate could go as high as 14% before making natural gas worse than coal when using 100-year GWP values. That value drops to 7% when using 20-year GWP values. Alvarez et al. (2012) plotted the relative radiative forcing of a system over time and found that a 3.2% leakage rate is the point at which natural gas becomes worse than coal as a fuel for producing the same megawatt-hr. of electric power.

Methane emissions during natural gas extraction, production, transmission, and distribution, taken together as “natural gas systems,” are reported in the Environmental Protection Agency’s (EPA) Inventory of U.S. Greenhouse Gas Emissions and Sinks (U.S. EPA, 2015). This value is estimated from bottom-up data, calculated using emission factors from available sets of emission measurements and estimates of activity. This inventory was recently updated to use data available through the EPA Greenhouse Gas Reporting Program (U.S. EPA, 2013), which includes emissions data, some of it direct measurement, reported by over 2000 facilities in the oil and gas industry. Taking the 2013 value for methane emissions from natural gas systems from the most recently released inventory report and accounting for total dry natural gas production as reported by the EIA (EIA, 2015), the methane leakage rate was approximately 1.35%.

A number of more recent efforts have been undertaken to use methane concentration data collected over a region to calculate an estimate of emissions from gas sites. These top-down approaches use aerial measurements, mobile surface surveys, and observed atmospheric methane from tall tower stations to study specific natural gas extraction and production sites over short periods of time, and as such, do not necessarily cover the entire range of methane emissions found in natural gas systems. Recent studies estimate the range of methane leakage rates from 2.3% to 17% (Caulton et al., 2014, Karion et al., 2013, Pétron et al., 2012). A study by Miller et al. (2013) found that methane emissions during natural gas production in south-central U.S. could be more than 2.7 times greater than most emission inventories. Despite the high estimates, one review of the available technical data reported that while there are likely some super emitters throughout the system, overall system-wide methane leakage is not high enough to negate the benefits of natural gas versus coal over a long time frame (Brandt et al., 2014). In line with that study, a recent study of the Haynesville, Fayetteville, and Marcellus shale plays, areas representing over half of U.S. shale production, estimated an average of 1.1% leakage, with a range of 0.18% to 2.8% (Peischl et al., 2015), and a study that took direct measurements of methane emissions at a large number of onshore natural gas sites estimated methane leakage of 0.42% in just the production phase (Allen et al., 2013).

A smaller set of studies have used energy systems and integrated assessment models to explore the potential of increased natural gas supply to serve as a bridge to renewables, a replacement for coal, and a key player in reducing greenhouse gas emissions. In general, these studies found that under increased natural gas supply scenarios, natural gas does replace some coal use in power production, but at the same time the increased resources also substitute for some new renewable generation and the reduced cost of those resources can lead to an increase in energy consumption (Huntington, 2013, Joint Institute for Strategic Energy Analysis (JISEA), 2016, Shearer et al., 2014, McJeon et al., 2014, Newell and Raimi, 2014). As a result, total system GHG emissions are either only slightly reduced or not reduced at all. McJeon et al. (2014), Shearer et al. (2014), and Newell and Raimi (2014) all varied upstream methane emissions in their analyses, from as low as 0% to as high as almost 8%, and found that the assumptions made about methane emissions had an impact on whether there was a slight increase or a slight decrease in system GHG emissions.

In this study, we expanded upon the studies cited above by using a bottom-up energy systems model to analyze the effects that different methane leakage rates would have on total GHG emissions under different scenarios of natural gas availability. We modeled a power sector emissions reduction strategy both with and without carbon dioxide and methane emissions from coal, oil, and natural gas extraction and production included in the emissions reduction calculation and analyzed how those strategies lead to different technology choices in the power sector.

3. Modeling approach

This analysis utilized the MARKet Allocation (MARKAL) energy systems model (LouLou et al., 2004) along with a database developed by the Environmental Protection Agency (EPA) Office of Research and Development. The EPAUS9r (Lenox et al., 2013) is a nine-region database representation of the United States energy system in which the nine regions correlate to the U.S. census divisions. The MARKAL model is a bottom-up, linear optimization model that finds a least cost pathway for meeting exogenously supplied energy system demands, taking into account user-defined constraints. The EPAUS9r represents the expanse of the energy system including resource extraction and import, process and conversion technologies to convert resources into useful forms, and end-use technologies available for meeting demands. End-use sectors represented within the EPAUS9r are residential, commercial, industrial, and transportation. There are 74 specific end-use demands supplied to the model in each of the regions, including commercial lighting, residential heating and cooling, personal vehicle miles traveled, and industrial sector outputs. A MARKAL model run optimizes resource supplies, technology options, and fuel use over a specified time horizon. Results can be evaluated on a regional scale (census divisions) or aggregated to the national level.

MARKAL is a deterministic model with base input assumptions about the costs, efficiencies, and availability of technologies to meet end-use energy demands. As with any assumptions, there are uncertainties associated and therefore the model results are interpreted as scenarios of what could happen given the inputs. While deterministic, this framework allows for scenario analyses where modifications of input assumptions are made which can inform an understanding of the impacts of certain fuels, technologies, or emissions rates within the energy system.

The data in the EPAUS9r database, including resource supply curves, technology costs and efficiencies, and end-use demands, are drawn primarily from the AEO2014, and the results are calibrated to the AEO2014 reference case. For this study, we used version 1.2 of the EPAUS9r. Assumptions that are important to this study include:

- Natural gas supply is represented by six-step supply curves in each of the regions.
- Canadian natural gas and liquefied natural gas (LNG) imports are modeled as supply curves.
- Natural gas exports to Mexico and later year LNG exports are modeled to match the AEO2014 projected amounts in each of the model years.
- The power sector utilizes a set of regional constraints that represent state Renewable Portfolio Standards (RPS) at the regional level. The data were drawn from the U.S. Department of Energy's Database of State Incentives for Renewables and Efficiency (DSIRE, 2010). As a result of these regional constraints, the EPAUS9r reference scenario uses 8% to 14% more renewable technologies in the power sector than the AEO2014 reference case. This increase in renewables offsets a percentage of the power sector natural gas use estimated in the AEO2014.
- The database includes emissions constraints that represent current air quality regulations, including the Clean Air Interstate Rule (CAIR) (Federal Register, 2005) and the Mercury and Air Toxics (MATS) rule (Federal Register, 2011).
- The database does not include a representation of the Clean Power Plan or recent tax credit extensions for wind and solar technologies.

The EPAUS9r includes a detailed representation of GHG and criteria air pollutant emissions. These factors are obtained from a number of sources including the EPA WebFire emission factor database (U.S. EPA, 2014a), Inventory of U.S. Greenhouse Gas Emissions and Sinks (U.S. EPA, 2015), EPA Greenhouse Gas Reporting Program (U.S. EPA, 2013), National Emissions Inventory (U.S. EPA, 2014b) and Argonne National Laboratory's Greenhouse Gases Regulated Emissions and Energy Use in Transportation (GREET) model (Wang et al., 2007). The database includes 20-year and 100-year GWPs for carbon dioxide, nitrous oxide, and methane taken from the IPCC Fifth Assessment Report (Myhre et al., 2013). GWP values for black carbon, carbon monoxide, nitrogen oxides, organic carbon, sulfur dioxide (SO_2), and volatile organic compounds are also included and are taken from a study by Akhtar et al. (2013).

The CH_4 factors utilized in this study are shown in Table 1. Starting in 2020, the CH4 emission factors are decreased to account for the implementation of New Source Performance Standards (NSPS) in the oil and gas sector that mandates green completions during well drilling activities (Federal Register, 2012). Based on the span of emissions estimates from the literature for natural gas, we choose to model methane leakage rates for the extraction and production portion of the upstream natural gas system of 1.0%, 2.3%, 4.0%, and 7.0% of total natural gas produced. The 1% leakage rate is aligned with the top-down study by Peischl et al. (2015) which found a weighted average 1.1% leakage from natural gas production. The higher estimates are taken from Caulton et al. (2014) which stated a range of 2.3%–11% as leakage rate for natural gas extraction and production. We used the average of that range, 7%, as our highest leakage rate. Having established the bounds for our scenario analysis, a 4% leakage rate was modeled to give an additional point between 2.3% and 7%. The transmission and distribution leakage rate was modeled separately and kept constant at 0.6% in all runs and was based on the GREET model (Wang et al., 2007).

4. Scenarios

A total of twenty-two scenario runs were performed for this analysis. The scenarios were combinations of four different variables: natural gas resource levels, power sector technology performance standards, upstream methane emissions estimates, and reductions in regional renewable portfolio standard goals. Table 2 lists the 22 scenarios and their given names. It should be noted that the methane leakage rate has no bearing on the model choices for the three initial Natural Gas Resource Level scenarios or the three initial Technology Performance Standard scenarios. In the comparison of CO_{2e} results found in Table 3 (Results and Discussion section), the CO_{2e} values for each of these scenarios is calculated using the specified leakage rate for each set of scenarios being compared.

4.1. Natural gas resource levels

The study included three different natural gas resource availability cases: reference (REF), high (HR), and low (LR). To model differences in availability, the natural gas supply curve costs were adjusted in the database based on the EMF31 scenario design. The reference case supply curves are based on the natural gas supply curves utilized in AEO2014 reference case. The natural gas supply curves for high and low resource cases were modeled in accordance with the AEO2014 high oil and gas resource case and AEO2014 low oil and gas resource case, respectively. In the HR case, EIA assumed ultimate recovery from unconventional wells to be 50% higher, leading to lower overall prices for domestic natural gas. In the LR case, estimated ultimate recovery is assumed to be 50% lower, leading to higher natural gas costs. In addition, the amount of natural gas and LNG exports were modeled according to the projected amounts in the AEO2014 for the high and low oil and gas cases. This means that exports increase in the high resource case and decrease in the low resource case. The AEO2014 high oil and gas resource case also projects that increases in natural gas resources lead to increases in chemical manufacturing output and aluminum production in the industrial sector, thus leading to increase in energy demand for these sectors. This demand increases are accounted for in the HR case.

4.2. Technology performance standard

In the technology performance standard (TPS) case, we established an average CO_2 emissions rate standard (in kilotonnes per petajoule) across existing and new power generators. Based on the EMF31 scenario design, the standard includes all fossil generators and renewable electricity generation, with the exception of hydroelectric. The rate is set up as a model constraint which forces the power sector to stay below a certain level of average CO_2 emissions per unit of electricity output. Different from the EMF31 standard TPS design, we modeled the rate for a given year as a percent reduction from the year 2005 instead of constraining the model to meet a predetermined rate. The result is that we achieved a smaller overall reduction in CO_2 emissions than other modeling teams participating in the study. Reductions of 26% in 2020 and 2025, 30% in 2030, and 1% per year additional thereafter are applied. For the TPS, the amount of CO_2 per unit of electricity output is calculated using the CO_2 emissions from the power sector only. The TPS case was applied to all three of the natural gas resource cases.

4.3. Technology performance standard including upstream emissions

A second technology performance scenario (TPS2) was modeled to analyze the impact of upstream emissions from natural gas extraction and production. For this case, a technology performance standard was developed in the same way as the TPS case, but with the emissions portion of the standard based on the carbon dioxide and methane emissions, in CO_2e, from resource extraction and production in addition to the CO_2 from power sector fuel combustion. The methane emissions are converted to CO_2e using the 100-year GWP. In the database, CO_2 and CH_4 emission factors for resource extraction and production, in kilotonnes per petajoule of fuel use, are added to the power sector technologies that use coal, oil, and natural gas as fuels. The TPS2 was modeled separately with each of the natural gas resource levels and at each of the four measures of upstream methane emissions. The upstream CO_2 and CH_4 emissions for coal and oil is kept constant in all scenarios.

4.4. Renewable portfolio standard reduction

A final set of four scenarios was run in which the high natural gas resource case was again modeled across each of the four measures of upstream methane emissions, but with a reduction in the power sector RPS constraints. This reduces the minimum amount of renewable power production required in each of the regions. The reductions start in 2020, and by 2030 regions can generate up to 30% less of their power from renewables as compared to the reference scenario.

5. Results and discussion

We focus our analysis on the results from scenarios in which the natural gas resource levels and the upstream methane emissions from natural gas production are varied under the two different power sector emissions reduction strategies. We looked at the changes in CO_2 and total GHG emissions as well as changes in technology choices in the power sector. The emissions analyzed are system-wide emissions to account for the interactions among the different sectors in the energy system.

Fig. 1 compares the consumption of natural gas between the reference scenario and the high and low natural gas resource scenarios. The reduction in the price of natural gas in the high resource scenario (HR) leads to a 20% increase in total natural gas consumption by 2050. Approximately 80% of the increase in natural gas used within the U.S. energy system is in the power sector. Another 14% is in the industrial sector, and the rest is spread between the residential, commercial, and transportation sectors. The increase in price of natural gas in the low resource scenario (LR) leads to an 8% reduction in consumption by 2050. Approximately 78% of the reduction is in the power sector, 19% in industrial, and the remaining spread between the other sectors. The system-wide CO_2 emissions resulting from the natural gas resource scenarios are shown in Fig. 2.

The TPS used in this analysis is very modest. Because the emissions reductions are applied over both existing and new power generation technologies, and include non-hydroelectric renewables, the model is able to meet the standard with small changes in the power sector. The reference scenario, with current trends in the power sector in which both natural gas and renewable technology installations increase over time, already achieves a 21% reduction in CO_2 per unit of output by 2020 and a 28% reduction by 2030. This means that the TPS targets of 25% by 2020 and 30% by 2030 are only slight changes. In the low resource scenario, a higher percentage of the existing coal plants continue to operate than in the reference scenario and the high resource scenario. As a result, the low resource scenario has only an 18% reduction in CO_2 per unit of output by 2020 and a 25% reduction by 2030. Therefore, the TPS leads to slightly larger changes in the power sector when applied to the low resource scenario. On the other hand, the increase in natural gas generation in the high resource scenario results in the scenario meeting or exceeding the rate standard, with a 25% reduction in 2020 and a 37% reduction in 2030 before the TPS is applied. As a result of the low gas prices, the system meets this TPS without any additional cost. There is no difference in the technology mix, fuel use, cost, or emissions between the high resource scenario and the high resource with the TPS scenario.

Over the three natural gas resource scenarios, the TPS leads to reductions in CO_2 in the power sector only in 2030 of 19% to 20% as compared to 2005. System-wide, this leads to a 12% to 13% reduction in CO_2. Fig. 3 shows the percent change in cumulative system-wide CO_2 emissions as compared to the reference scenario for the natural gas resource scenarios alone and each of the resource scenarios with the TPS. Cumulative CO_2 emissions from 2010 through 2050 decrease in the high resource scenario and all three of the TPS scenarios. The decrease is from 1.6% to 2.1%. These decreases come primarily from the replacement of coal with natural gas and renewables in the power sector. In the low resource scenario without the TPS there is a slight overall increase because the high cost of natural gas keeps some coal facilities in production for a longer period of time.

Fig. 4 highlights the change in total fuel use in electricity production over the reference scenario from 2010 through 2050. Whereas the high and low resource scenarios and the TPS at the reference (TPS) and high resource (TPS_HR) levels increase renewables by less than 1% over the model time horizon, the TPS with the low gas resources (TPS_LR) adds more than 7% renewable capacity.

For the six scenarios that have been highlighted so far (REF, HR, LR, TPS, TPS_HR, and TPS_LR), the choices in technologies used in the power sector do not change with differences in the upstream methane emissions. Technology choice does change, though, with the implementation of the second technology performance standard (TPS2). The TPS2 incorporates resource extraction and production CO_2 and CH_4 emissions into the emissions rate standard calculation along with CO_2 emissions from combustion in the power sector. The rate is stated in kilotonnes CO_2e per petajoule output. The TPS2 was applied to each of the natural gas resource level scenarios across all four of the estimates of upstream methane leakage from natural gas extraction and production (1%, 2.3%, 4% and 7%). The TPS2 leads to reductions in CO_2 in the power sector only in 2030 of 27% to 29% as compared to 2005. System-wide, this leads to a 13% to 16% reduction. The cumulative system-wide CO_2 emissions decreased for every model run as shown in Fig. 5.

Despite the reductions in cumulative CO_2 emissions when the TPS and the TPS2 are applied, the total change in GHG emissions varies across the scenarios. Table 3 shows snapshots of the percent change in total GHG emissions, represented by CO_2e, over the reference scenario of each of the runs in the years 2025, 2035, and 2050 using both 20-year and 100-year GWP values. It is important to note that the reference case CO_2e is different for each set of runs at different methane leakage rates. Therefore, a direct comparison cannot be made between the change in CO_2e in the high methane leakage scenarios and the change in CO_2e in the low methane leakage scenarios. What is important is the similar trends found at each methane leakage level. The CO_2e values are for the entire system, not just the power sector, and include emissions for carbon dioxide, methane, nitrous oxide, black carbon, carbon monoxide, nitrogen oxides, organic carbon, sulfur dioxide, and volatile organic compounds. CH_4 has a shorter atmospheric lifetime than CO_2, therefore, we looked at CO_2e using both 100-year and 20-year GWPs. The differences between the two time horizons illustrate the effect of short-lived climate forcing. Table cells highlighted in grey are instances when the difference in CO_2e is greater than zero, indicating that the system has a higher warming potential than the reference scenario. Table cells with bold, italicized numbers indicate periods when the CO_2e has decreased more than 4%.

As expected, at lower estimates of upstream methane emissions, most of the scenarios without a TPS result in a reduction in overall CO_2e, and therefore a reduction in the global warming impact of the system. One exception is the low resource scenario in scenarios with lower methane leakage rates for natural gas production. In those scenarios, coal power plants stay in production for longer periods of time as compared to the reference case, and the higher coal combustion emissions leads to an increase in CO_2 and CO_2e in the early years. The TPS and the TPS2 reduce the CO_2e emissions in all time periods under both GWP time frames in the reference resource level scenarios and the low resource scenarios, with the low resource scenarios consistently delivering larger reductions. Fig. 6 shows that this benefit to the system is the result of coal capacity, and some or to a lesser extent natural gas, being replaced with renewable (mostly wind) production.

The high natural gas resource scenarios, with their increased use of natural gas in the power sector, result in increased CO_2e emissions in a number of the time periods, especially when using a 20-year time frame for GWP at higher upstream natural gas methane emissions. The high resource scenarios are not only impacted by the increase in natural gas use, but also by other system changes. Increased availability of natural gas at a lower price leads to an increase in output in a few of the industrial sub-sectors. This leads to a small increase in total electricity production due to the increase in output from the industrial sector, shown in Fig. 7. There is also a slight increase in compressed natural gas used in transportation. Even so, the predominant cause of the increase in CO_2e in the high resource scenarios is the increase in methane emissions from natural gas extraction and production.

The system-wide CO_2e emissions include the effects of all GHGs, including those that have a negative radiative forcing. The largest of these in terms of system-wide emissions is SO_2. SO_2 in the atmosphere transforms into sulfate aerosols which contribute to the scattering of solar radiation back to space, keeping that radiation from reaching the earth's surface. In GWP terms, the 100-year GWP for SO_2 is − 25 compared to the GWP for CH_4 of 28. The 20-year GWP is − 100 compared to 84 for CH_4. In the early years of the model time horizon, system-wide SO_2 emissions are very close to CH_4 emission, and in effect, the contribution to warming cancel each other out. This changes over time as air quality regulations take effect and system-wide SO_2 is greatly reduced while CH_4 from natural gas resources increases. In addition, Fig. 8 shows that as the use of natural gas in the power sector replaces coal, especially in the high resource scenarios, the overall system SO_2 emissions are reduced. Therefore, the more natural gas used in the power sector, the less SO_2 in the atmosphere to counter the positive radiative forcing of other GHGs. It is important to note that this is only one aspect of fewer SO_2 emissions, as the reduction in SO_2 is likely to have a significant health benefit due to fine particle reductions.

A final set of scenarios was run to look at the effect of reducing the renewable portfolio standards (RPSs) in the case of high natural gas resources. In theory, this approach looks at what happens if the increased availability of cheaper natural gas and its known potential to reduce CO_2 emissions in the system leads states to reduce their planned RPS goals. At all levels of upstream methane emissions, a reduction in the RPSs led to an increase in natural gas replacing renewable technologies that would otherwise have been installed. As shown in Fig. 9, at each time period and for each level of upstream emissions, this reduction in the RPSs led to an average increase in both the 100-year and 20-year CO_2e values. Therefore, when the overall global warming potential is lower than the reference scenario, that reduction is not as great when the RPS is reduced. When the global warming potential is already greater than the reference case, it is increased even higher by the RPS reduction.

6. Conclusions and recommendations

At reference levels of natural gas availability and price, as well as when natural gas is more expensive and less available, the technology changes made in the power sector to meet the emissions reduction targets specified in this study leads to reductions in both total system CO_2 and system CO_2e emissions across all upstream natural gas methane leakage rates. However, when natural gas prices remain low and natural gas is more widely available, a higher upstream methane leakage rate can shift the system away from the benefit that natural gas brings. Our study shows that when the transportation and distribution leakage rate of 0.6% is factored back in (e.g., the 2.3% runs have a total leakage rate of 2.9%), there is virtually no improvement or only very slight improvements in system-wide GHG emissions starting as low as a 2.9% leakage rate as compared to the reference case over a 100-year time period out in the later years. Increases in total system CO_2e emissions are more pronounced at the much higher leakage rates of 4.6% and 7.6%. The loss in benefit is more pronounced using a 20-year GWP. This occurs due to the system choosing to install a larger amount of natural gas production capacity in the power sector over the reference case, replacing not only existing coal production but also some of the renewable capacity that would otherwise have been installed.

While a 2.9% methane leakage rate is more than twice as high as the 1.35% estimate calculated using data from the EPA GHG inventory, 2.9% falls below some of the estimates in both bottom-up analyses and top-down measurement studies. This study highlights the need to continue to develop measurement studies, especially direct measurement studies, to determine the sources of methane leakage and to develop advanced detection and control strategies to minimize or eliminate those leaks. There is a substantial amount of effort currently underway by multiple institutions, coordinated by the Environmental Defense Fund (2015), to try to reconcile bottom-up and top-down measurements and to better estimate methane emissions throughout the natural gas system. Many of the studies in that series will include direct measurements for most major methane-producing activities and equipment types in natural gas systems.

Finally, this analysis highlights that an emissions reduction strategy that takes into account upstream emissions for all fuels being used in the power sector is a highly robust strategy across all levels of natural gas availability and at each estimate of methane leakage. At every level of upstream methane leakage, the TPS2 strategy resulted in larger reductions in both CO_2 and CO_2e emissions across the energy system. When addressing broader system carbon emissions, using a technology performance standard that takes into account upstream emissions for all fuels leads to additional benefits in terms of CO_2e emissions reductions than focusing on the power sector alone.

Supplementary Material

Refer to Web version on PubMed Central for supplementary material.

Acknowledgments

This research was funded through the EPA Air, Climate, and Energy (ACE) program office. The EPAUS9r MARKAL database has been developed over a number of years by a number of researchers in the U.S. EPA's Office of Research and Development. The current version of the database was a collaborative effort of ORD's Energy and Climate Assessment Team, including Rebecca Dodder, Dan Loughlin, and William Yelverton. A major update to the industrial sector was done with contract support from Jonathan Witt.

References

Akhtar FH, Pinder RW, Loughlin DH, Henze DK. GLIMPSE: a rapid decision framework for energy and environmental policy. Environ. Sci. Technol, 47 (21) (2013), pp. 12011–12019, 10.1021/es402283j [PubMed: 24044746]

Allen DT, Torres VM, Thomas J, Sullivan DW, Harrison M, Hendler A, Herndon SC, Kolb CE, Fraser MP, Hill AD, Lamb BK, Miskimins J, Sawyer RF, Seinfeld JH. Measurements of methane emissions at natural gas production sites in the United States. Proc. Natl. Acad. Sci. U. S. A, 110 (17) (2013), pp. 768–17.773, 10.1073/pnas.1304880110

Alvarez RA, Pacala SW, Winebrake JJ, Chameides WL, Hamburg SP. Greater focus needed on methane leakage from natural gas infrastructure. Proc. Natl. Acad. Sci. U. S. A, 109 (2012), pp. 6435–6440, 10.1073/pnas.1202407109 [PubMed: 22493226]

Brandt AR, Heath GA, Kort EA, O'Sullivan F, Pétron G, Jordaan SM, Tans P, Wilcox J, Gopstein AM, Arent D, Wofsy S, Brown NJ, Bradley R, Stucky GD, Eardley D, Harriss R. Methane leaks from North American natural gas systems. Science, 343 (2014), pp. 733–735, 10.1126/science.1247045 [PubMed: 24531957]

Caulton DR, Shepson PB, Santoro RL, Sparks JP, Howarth RW, Ingraffea AR, Cambaliza MOL, Sweeney C, Karion A, Davis KJ, Stirm BH, Montzka SA, Miller BR. Toward a better understanding and quantification of methane emissions from shale gas development. Proc. Natl. Acad. Sci. U. S. A, 111 (17) (2014), pp. 6237–6242, 10.1073/pnas.1316545111 [PubMed: 24733927]

DSIRE. N.C. Clean Energy Technology Center Database of State Incentives for Renewables and Efficiency. (2010) Available at: http://www.dsireusa.org/rpsdata/index.cfm (Last accessed April 22, 2015)

Environmental Defense Fund. Methane Research: The 16 Study Series Fact Sheet. (2015) Available at: http://www.edf.org/sites/default/files/methane_studies_fact_sheet.pdf (Last accessed on April 22, 2015)

Federal Register. Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NOx SIP Call. 40 CFR Parts 51. 72, 73, 74, 77, 78 and 96, No: OAR-2003–0053; FRL-7885–9, 70(90). Environmental Protection Agency (2005) (5/12)

Federal Register. National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel-Fired Electric Utility, Industrial–Commercial–Institutional, and Small Industrial–Commercial–Institutional Steam Generating Units. 40 CFR Part 63, No.: EPA-HQ-OAR-2009–0234; EPA-HQ-OAR-2011–0044, FRL-9286–1. Environmental Protection Agency (2011) (12/16)

Federal Register. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule. 40 CFR Parts 60 and 63, No.: EPA-HQ-OAR-2010–0505; FRL-9665–1. Environmental Protection Agency (2012) (08/16)

Heath GA, O'Donoughue P, Arent DJ, Bazilian M. Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation. Proc. Natl. Acad. Sci. U. S. A, 111 (2014), 10.1073/pnas.1309334111

Hultman N, Rebois D, Scholten M, Ramig C. The greenhouse impact of unconventional gas for electricity generation. Environ. Res. Lett, 6 (2011), 10.1088/1748-9326/6/4/011008

Huntington H. Energy Modeling Forum Study #26: Changing the Game? Emissions and Market Implications of New Natural Gas Supplies Volume 1, Publication Date: Sep 1 2013 Stanford University, Stanford, CA (2013) (Available at: https://web.stanford.edu/group/emf-research/docs/emf26/Summary26.pdf, Last accessed on May 4, 2016)

Jiang M, Griffin WM, Hendrickson C, Jaramillo P, VanBriesen J, Venkatesh A. Life cycle greenhouse gas emissions of Marcellus shale gas. Environ. Res. Lett, 6 (2011), 10.1088/1748-9326/6/3/034014

Joint Institute for Strategic Energy Analysis (JISEA). Considering role of natural gas in the deep decarbonization of the U.S. electricity sector. Cole W, Beppler R, Zinaman O, Logan J (Eds.), NREL/TP-6 A50–64654, National Renewable Energy Laboratory, Golden, CO, USA (2016) (Available at: http://www.nrel.gov/docs/fy16osti/64654.pdf. Last accessed on May 4, 2016)

Karion A, Sweeney C, Pétron G, Frost G, Hardesty RM, Kofler J, Miller BR, Newberger T, Wolter S, Banta R, Brewer A, Dlugokencky E, Lang P, Montzka SA, Schnell P, Tans P, Trainer M, Zamora R, Conley S. Methane emissions estimate from airborne measurements over a western United States natural gas field. Geophys. Res. Lett, 40 (2013), pp. 4393–4397, 10.1002/grl.50811

Lenox C, Dodder R, Gage C, Kaplan O, Loughlin D, Yelverton W. EPA U.S. nine-region MARKAL database: database documentation. Office of Research and Development, U.S. Environmental Protection Agency, No.: EPA 600/B-13/203 (2013) Available at: http://cfpub.epa.gov/si/si_public_record_Report.cfm?dirEntryId=278925&CFID=36235307&CFTOKEN=34660040&jsessionid=cc308791e9d5b702ad59412787521533d523 (Last accessed on April 22, 2015)

Loulou R, Goldstein G, Noble K. Documentation for the MARKAL family of models. Energy Technology Perspectives Programme (2004) Available at: http://www.etsap.org/MrklDoc-I_StdMARKAL.pdf (Last accessed on April 22, 2015)

McJeon H, Edmonds J, Bauer N, Clarke L, Fisher B, Flannery BP, Hilaire J, Krey V, Marangoni G, Mi R, Riahi K, Rogner H, Tavoni M. Limited impact on decadal-scale climate change from increased use of natural gas. Nature, 514 (7523) (2014), pp. 482–485, 10.1038/nature13837 [PubMed: 25317557]

Miller SS, Wofsy SC, Michalak AM, Kort EA, Andrews AE, Biraud SC, Dlugokencky EJ, Eluskiewicz J, Fischer ML, Janssens-Maenhout G, Miller BR, Miller JB, Montzka SA, Sweeney C.

Anthropogenic emissions of methane in the United States. Proc. Natl. Acad. Sci. U. S. A, 110 (2013), 10.1073/pnas.1314392110

Myhre G, Shindell D, Bréon F-M, Collins W, Fuglstvedt J, Huang J, Koch D, Lamarque J-F, Lee D, Mendoza B, Nakajima T, Robock A, Stephens G, Takemura T, Zhang H, Aamaas B, Boucher O, Dalsøren SB, Daniel JS, Forster P, Granier C, Haigh J, Hodnebrog Ø, Kaplan JO, Marston G, Nielsen CJ, O'Neill BC, Peters GP, Pongratz J, Prather M, Ramaswamy V, Roth R, Rotstayn L, Smith SJ, Stevenson D, Vernier J-P, Wild O, Young P. Anthropogenic and Natural Radiative Forcing. Stocker TF, et al. (Eds.), Climate Change 2013: The Physical Science Bases Contributions of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA (2013)

National Energy Technology Laboratory (NETL). Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production. No: DOE/NETL 2011/1522 (2011) (Available at: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Life%20Cycle%20Analysis/NG-GHG-LCI.pdf. Last accessed on April 22, 2015)

National Renewable Energy Laboratory (NREL) (2012) "U.S. Life Cycle Inventory Database." National Renewable Energy Laboratory, 2012. (Available at: https://www.lcacommons.gov/nrel/search, Last accessed on June 8, 2015).

Newell RG, Raimi D. Implications of shale gas development for climate change. Environ. Sci. Technol, 48 (15) (2014), pp. 8360–8368, 10.1021/es4046154 [PubMed: 24754840]

Peischl J, Ryerson TB, Aikin KC, de Gouw JA, Gilman JB, Holloway JS, Lerner BM, Nadkarni R, Neuman JA, Nowak JB, Trainer M, Warneke C, Parrish DD. Quantifying atmospheric methane emissions from the Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions. J. Geophys. Res. Atmos., 120 (2015), pp. 2119–2139, 10.1002/2014JD022697

Pétron G.G.Frost , Miller BR, Hirsch AI, Montzka SA, Karion A, Trainer M, Sweeney C, Andrews AE, Miller L, Kofler J, Bar-Ilan A, Dlugokencky EJ, Patrick L, Moore CT Jr., Ryerson TB, Siso C, Kolodzey W, Lang PM, Conway T, Novelli P, Masarie K, Hall B, Guenther D, Kitzis D, Miller J, Welsh D, Wolfe D, Nedd W, Tans P. Hydrocarbon emissions characterization in the Colorado front range: a pilot study. J. Geophys. Res, 117 (2012), p. D04304, 10.1029/2011JD016360

Shearer C, Bistline J, Inman M, Davis SJ. The effect of natural gas supply on US renewable energy and CO2 emissions. Environ. Res. Lett, 9 (9) (2014), p. 094008 (Retrieved from http://stacks.iop.org/1748-9326/9/i=9/a=094008)

Stephenson T, Valle JE, Riera-Palou X. Modeling the relative GHG emissions of conventional and shale gas production. Environ. Sci. Technol, 45 (2011), pp. 10757–10764, 10.1021/es2024115 [PubMed: 22085088]

U.S. EIA. Annual Energy Outlook 2014 with Projections to 2040. Office of Integrated Analysis and Forecasting, U.S. Energy Information Administration, No.: DOE/EIA-0383(2014). (2014) Available at: http://www.eia.gov/forecasts/aeo/pdf/0383%282014%29.pdf (Last accessed on April 22, 2015)

U.S. EIA. Natural Gas Gross Withdrawals and Production. (2015) Available at: http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm (Last accessed on June 4, 2015)

U.S. EPA. The Greenhouse Gas Reporting Program. U.S. Environmental Protection Agency (2013) (Available at: http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html. Last accessed on June 5, 2015)

U.S. EPA. Download WebFIRE data in bulk Technology Transfer Network Clearinghouse for Inventories & Emission Factors. U.S. Environmental Protection Agency (2014a) (Available at: http://cfpub.epa.gov/webfire/, Last accessed on April 22, 2015)

U.S. EPA. The 2011 National emissions inventory. U.S. Environmental Protection Agency (2014b) (Available at: http://www.epa.gov/ttn/chief/net/2011inventory.html, Last accessed on June 5, 2015)

U.S. EPA. Inventory of U.S. greenhouse gas emissions and sinks: 1990–2013. No. EPA 430-R-15–004. U.S. Environmental Protection Agency (2015) (Available at: http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Main-Text.pdf, Last accessed on June 4, 2015)

Venkatesh A, Jaramillo P, Griffin WM, Matthews HS. Uncertainty in life cycle greenhouse gas emissions from United States natural gas end-uses and its effects on policy. Environ. Sci. Technol, 45 (2011), pp. 8182–8189, 10.1021/es200930h [PubMed: 21846117]

Venkatesh A, Jaramillo P, Griffin WM, Matthews HS. Uncertainty in life cycle greenhouse gas emissions from United States coal. Energy Fuel, 26 (2012), pp. 4917–4923, 10.1021/ef300693x

Wang M, Wu Y, Elgowainy A. Operating Manual for GREET: Version 1.7. No.: ANL/ESD/05–3. Transportation Technology R&D Center, Argonne National Laboratory (2007)

Weber CL, Clavin C. Life cycle carbon footprint of shale gas: review of evidence and implications. Environ. Sci. Technol, 46 (2012), pp. 5688–5695, 10.1021/es300375n [PubMed: 22545623]

EPA Author Manuscript

EPA Author Manuscript

Highlights

- MARKAL analysis of energy system GHG emissions reduction scenarios.
- High methane leakage can eliminate the benefit that natural gas brings over coal.
- A robust GHG reduction strategy takes into account upstream emissions for all fuels.

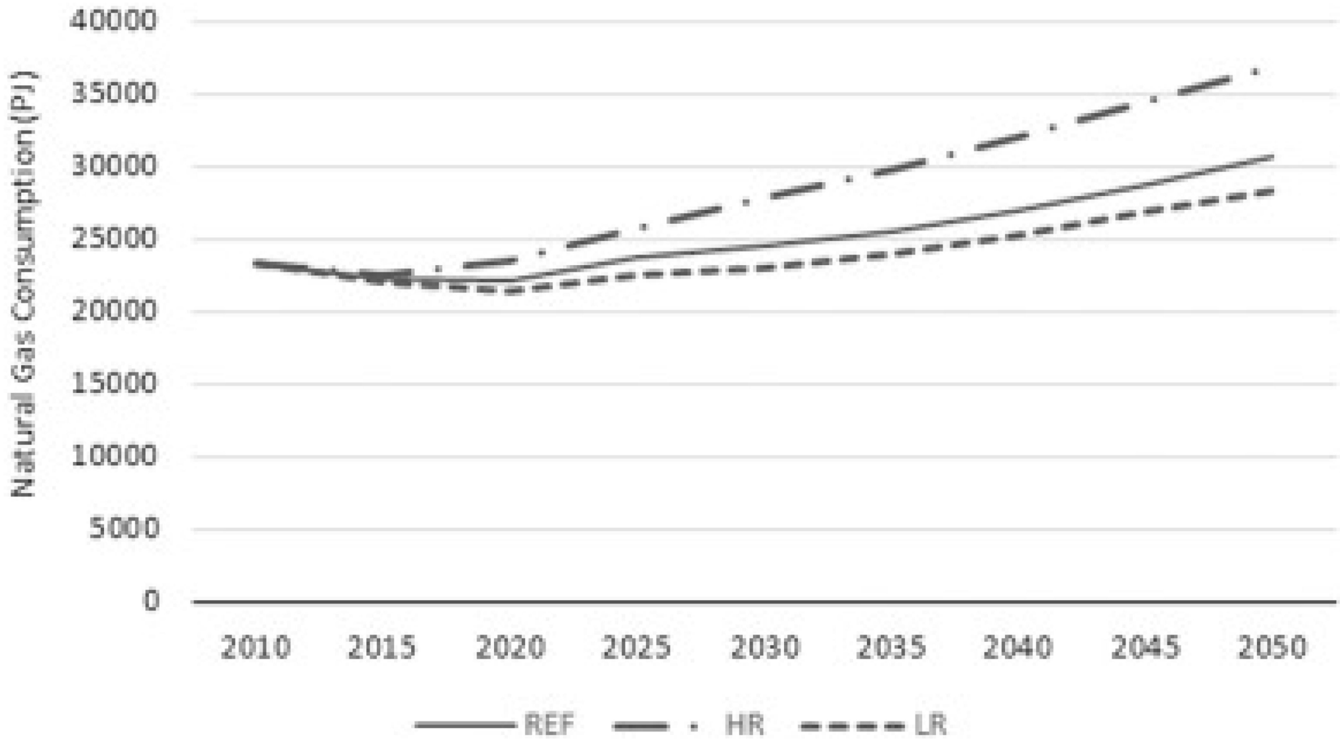

Figure 1.
Total U.S. consumption of natural gas in petajoules (PJ) for the reference (REF), high resource (HR), and low resource (LR) scenarios.

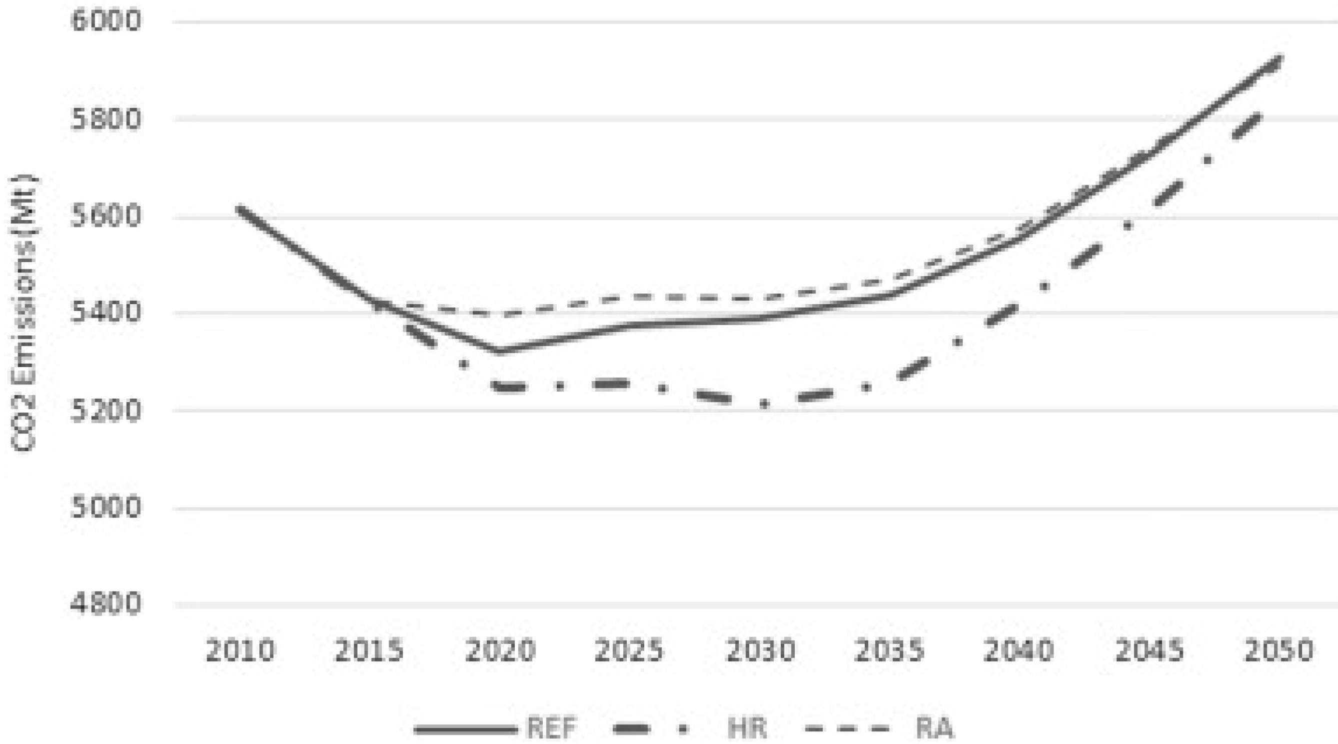

Figure 2.
System-wide CO_2 emissions in million tons (Mt) for the reference (REF), high resource (HR), and low resource (LR) scenarios..

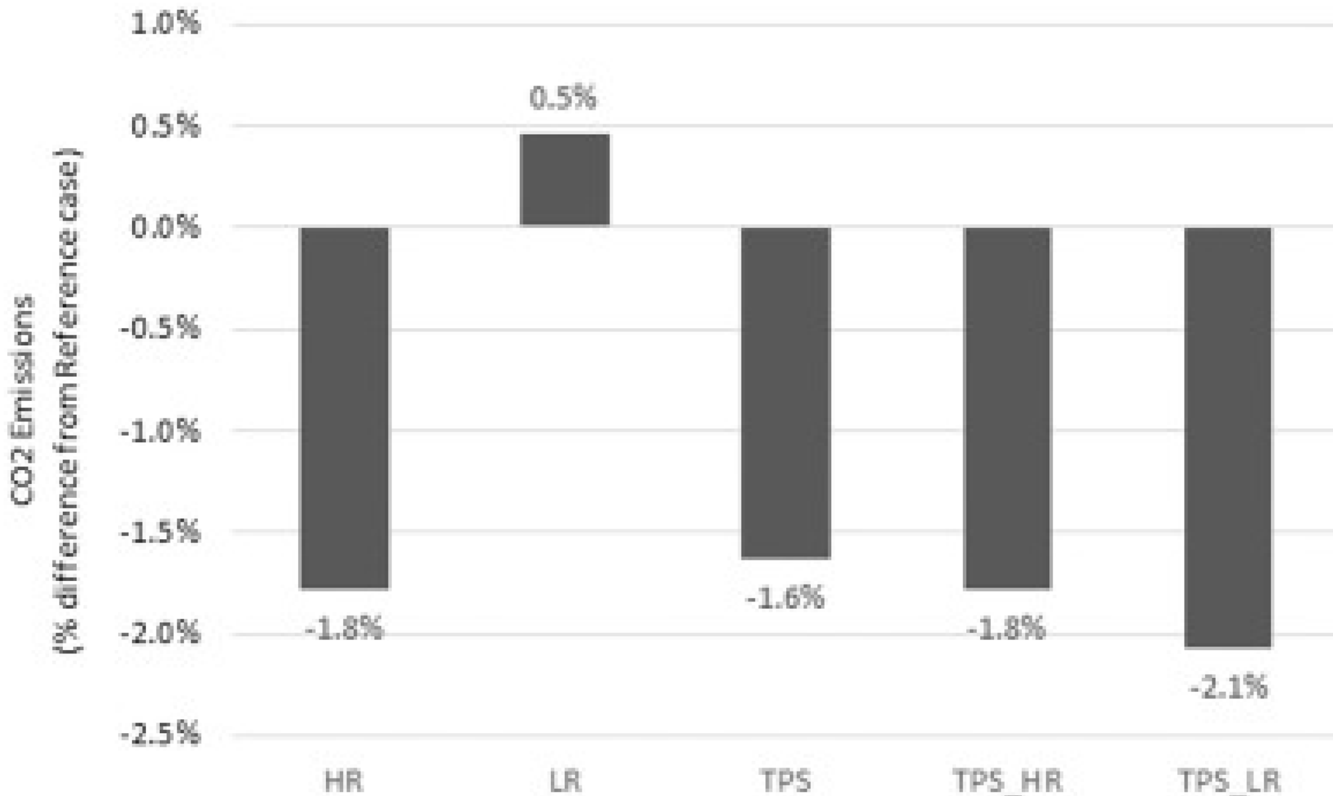

Figure 3.
Cumulative system-wide CO_2 emissions: 2010–2050, percent difference from the reference scenario.

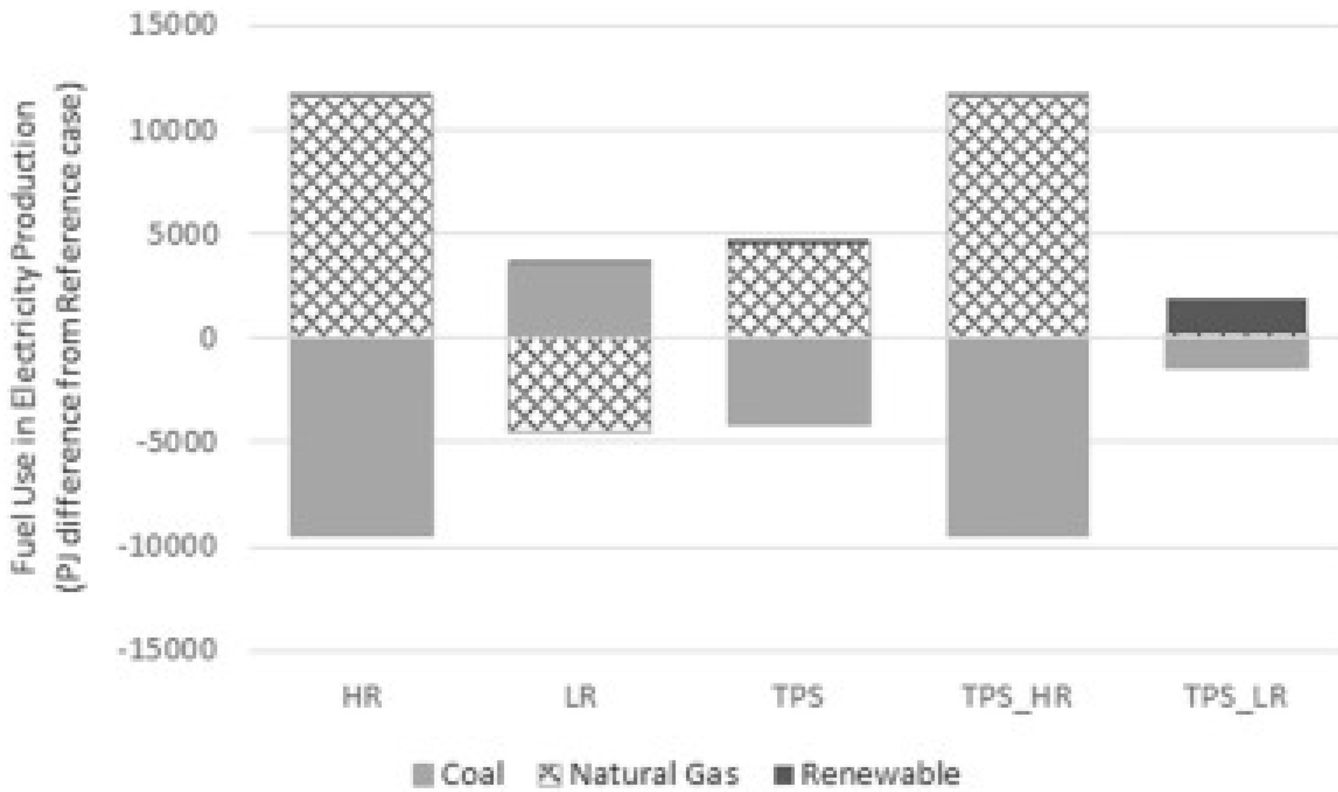

Figure 4.
Change in cumulative fuel use in electricity production in PJ: 2010–2050, as compared to the reference scenario.

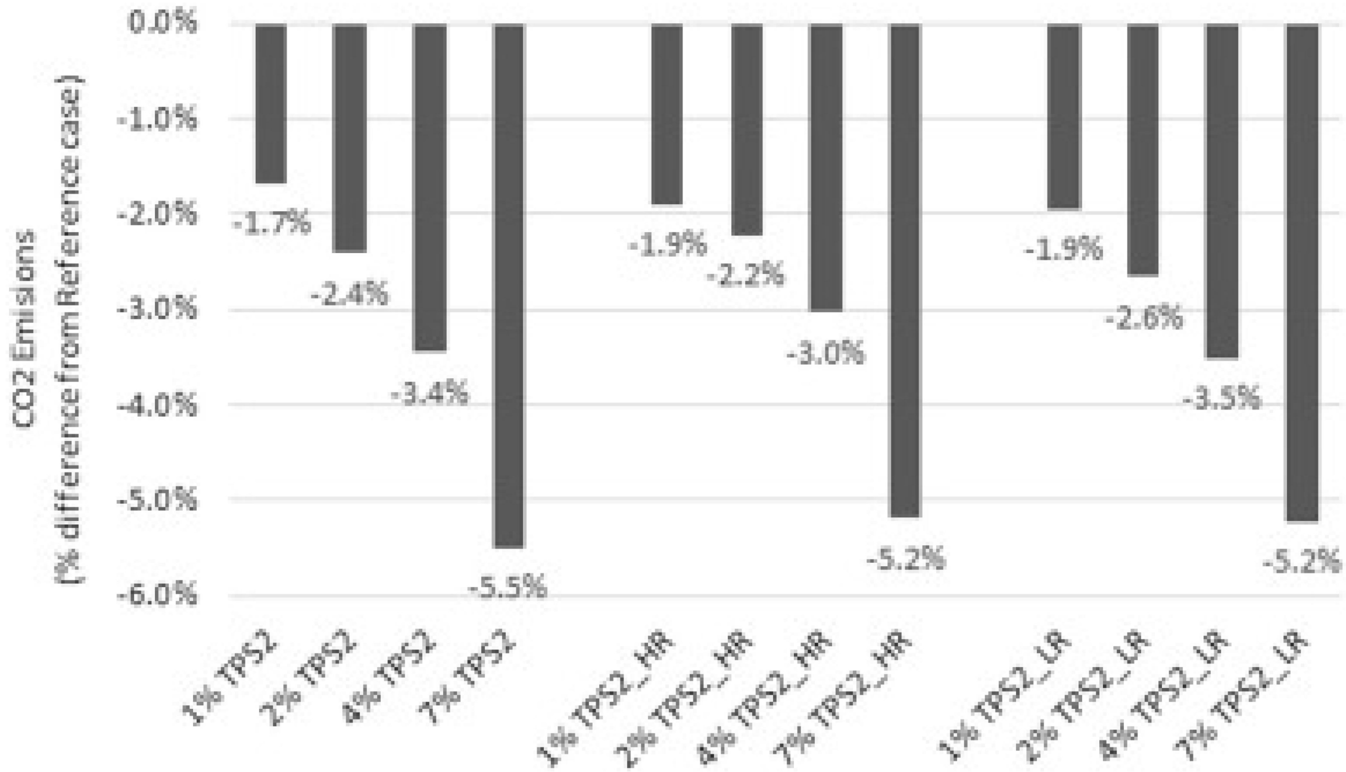

Figure 5.
Cumulative system-wide CO_2 emissions: 2010–2050, percent difference from the reference scenario.

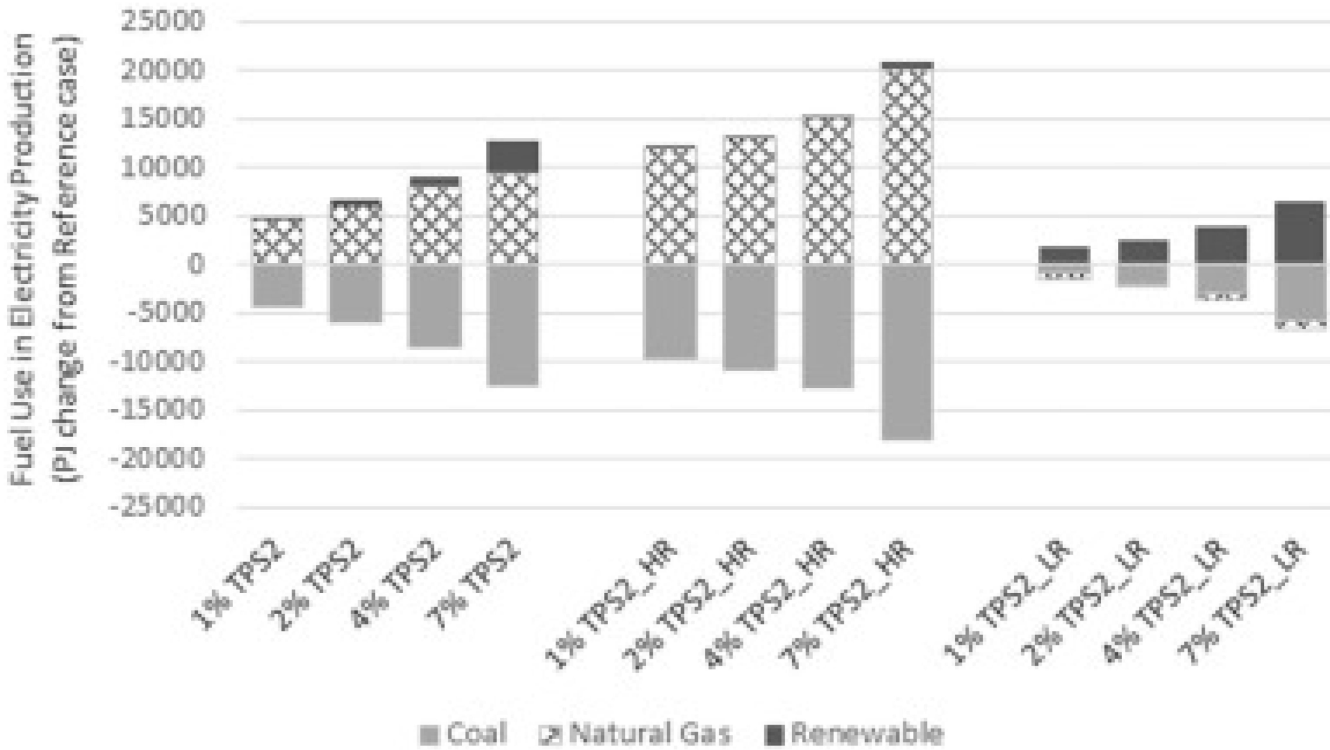

Figure 6.
Change in cumulative fuel use in electricity production in PJ: 2010–2050, as compared to the reference scenario.

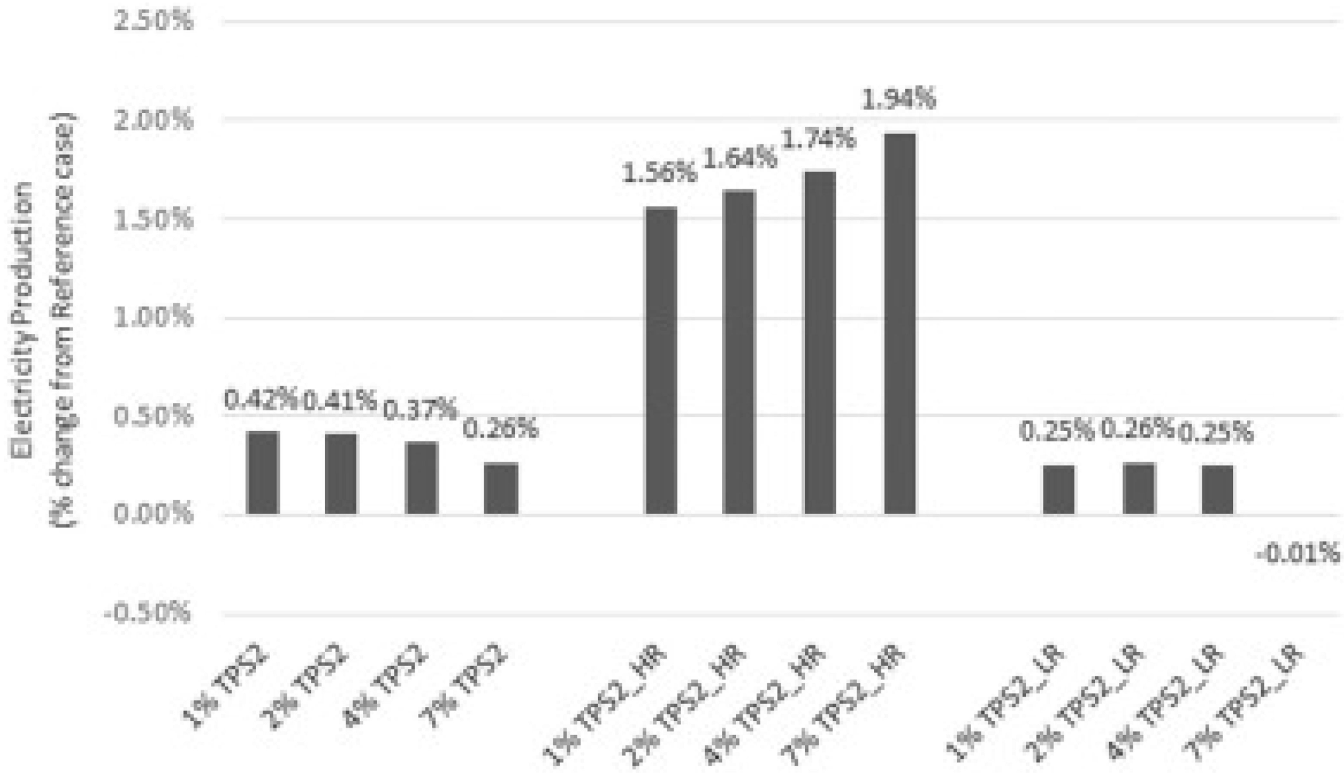

Figure 7.
Percent change in electricity production: 2010–2050, as compared to the reference scenario.

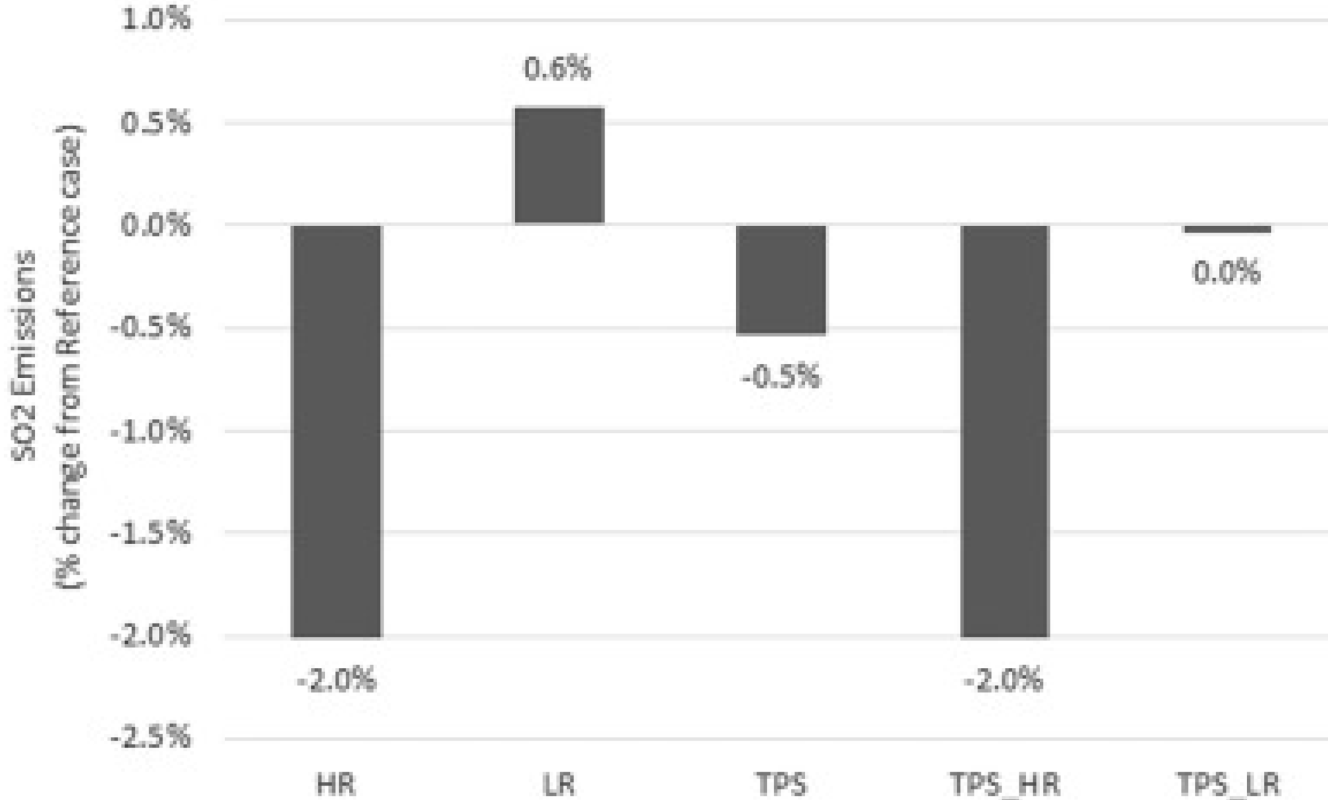

Figure 8.

Percent change in cumulative system-wide SO_2 emissions: 2010–2050, as compared to the reference scenario.

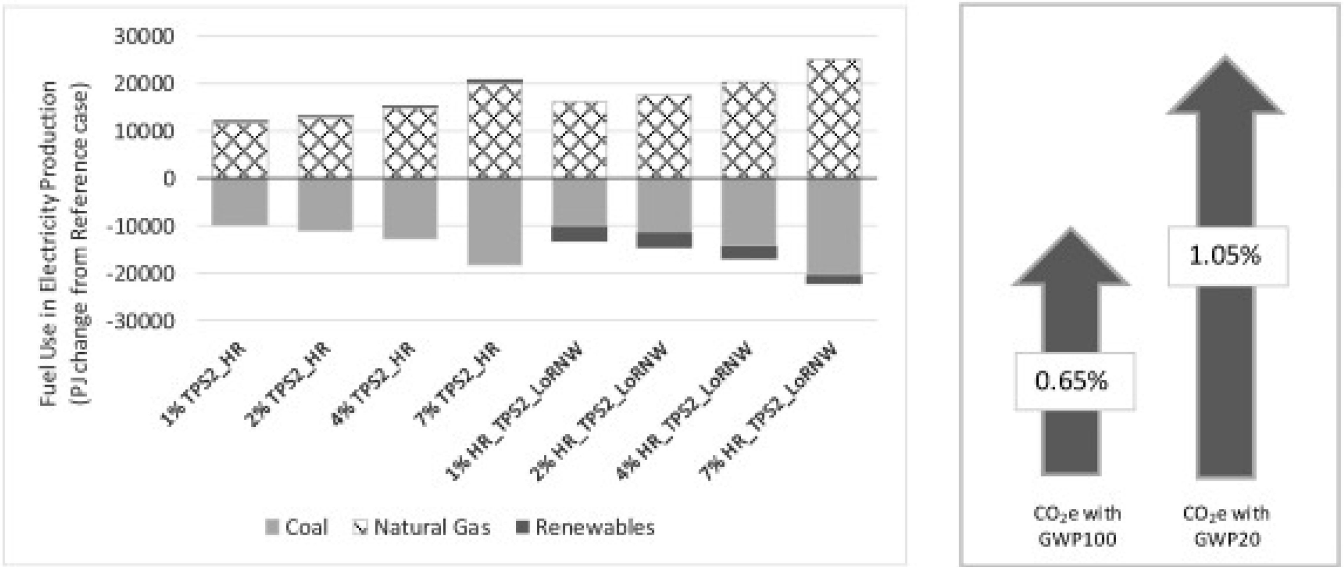

Figure 9.

Effect of reduced RPS constraint on fuel use in the power sector (in PJ) and cumulative CO_2e emissions.

EPA Author Manuscript

EPA Author Manuscript

Table 1.

Upstream CH_4 emissions used in the study for natural gas, coal, and oil.

		CH4	**CH4**	
		kt/PJ	**kt/PJ**	
Fuel	**Scenarios**	**2010–2015**	**2020–2055**	**References**
Natural gas extraction and production				
	1%	0.15	0.1	Peischl et al. (2015)
	2.30%	0.34	0.24	Low end of range in Caulton et al. (2014)
	4%	0.59	0.42	Modelers choice
	7%	1.03	0.73	Average of range in Caulton et al. (2014)
Natural gas transmission and distribution	All	0.07954	0.07954	GREET v1.8c, Wang et al. (2007)
Coal	All	0.15	0.15	Venkatesh et al. (2012)
Oil	All	0.081	0.081	NREL LCI Digital Commons (2012)

EPA Author Manuscript

EPA Author Manuscript

Table 2.

Scenario names and descriptions.

Natural gas resource levels	
REF	Reference case
HR	High natural gas resource
LR	Low natural gas resource
Technology performance standard (TPS)	
TPS	TPS with reference natural gas resource
TPS_HR	TPS with high natural gas resource
TPS_LR	TPS with low natural gas resource
TPS including upstream emissions	
1% TPS2	TPS2 with reference NG resource at 1% upstream methane emissions
2% TPS2	TPS2 with reference NG resource at 2.3% upstream methane emissions
4% TPS2	TPS2 with reference NG resource at 4% upstream methane emissions
7% TPS2	TPS2 with reference NG resource at 7% upstream methane emissions
1% TPS2_HR	TPS2 with high NG resource at 1% upstream methane emissions
2% TPS2_HR	TPS2 with high NG resource at 2.3% upstream methane emissions
4% TPS2_HR	TPS2 with high NG resource at 4% upstream methane emissions
7% TPS2_HR	TPS2 with high NG resource at 7% upstream methane emissions
1% TPS2_LR	TPS2 with low NG resource at 1% upstream methane emissions
2% TPS2_LR	TPS2 with low NG resource at 2.3% upstream methane emissions
4% TPS2_LR	TPS2 with low NG resource at 4% upstream methane emissions
7% TPS2_LR	TPS2 with low NG resource at 7% upstream methane emissions
Renewable portfolio standard (RPS) reduction	
1% HR_TPS2_LoRNW	TPS2 with high natural gas resource and reduced RPS at 1% upstream methane emissions
2% HR_TPS2_LoRNW	TPS2 with high natural gas resource and reduced RPS at 2.3% upstream methane emissions
4% HR_TPS2_LoRNW	TPS2 with high natural gas resource and reduced RPS at 4% upstream methane emissions
7% HR_TPS2_LoRNW	TPS2 with high natural gas resource and reduced RPS at 7% upstream methane emissions

EPA Author Manuscript
EPA Author Manuscript

Table 3.

Percent difference in cumulative system-wide CO_2e from reference scenario.

Natural Gas methan leakage	Scenarios	GWP100				GWP20		
		2025	2035	2050		2025	2035	2050
1%	TPS	−1.67	−1.75	−2.74		−1.44	−1.53	−2.44
	TPS2	−1.72	−1.83	−2.97		−1.45	−1.57	−2.58
	HR	−1.83	−2.78	−0.88		−1.17	−1.86	0.16
	TPS_HR	−1.83	−2.78	−0.88		−1.17	−1.86	0.16
	TPS2_HR	−1.85	−2.94	−1.02		−1.15	−1.95	0.10
	LR	0.87	0.27	−0.74		0.35	−0.32	−1.52
	TPS_LR	−1.39	−2.59	***−4.55***		−1.65	−2.94	***−4.97***
	TPS2_LR	−1.14	−2.34	***−4.72***		−1.40	−2.68	***−5.14***
2.3%	TPS	−1.54	−1.60	−2.55		−1.14	−1.18	−1.99
	TPS2	−2.05	−2.28	−3.99		−1.52	−1.68	−3.05
	HR	−1.40	−2.14	−0.07		−0.15	−0.35	2.08
	TPS_HR	−1.40	−2.14	−0.07		−0.15	−0.35	2.08
	TPS2_HR	−1.58	−2.70	−0.93		−0.29	−0.75	1.49
	LR	0.45	−0.24	−1.40		−0.64	−1.55	−3.07
	TPS_LR	−1.64	−2.94	***−5.00***		−2.27	−3.78	***−6.02***
	TPS2_LR	−1.84	−3.57	***−6.17***		−2.43	***−4.36***	***−7.17***
4%	TPS	−1.38	−1.42	−2.32		−0.79	−0.79	−1.50
	TPS2	−2.47	−3.07	**−5.25**		−1.60	−1.84	−3.35
	HR	−0.87	−1.37	0.92		1.00	1.32	4.18
	TPS_HR	−0.87	−1.37	0.92		1.00	1.32	4.18
	TPS2_HR	−1.60	−2.45	−1.64		0.45	0.58	2.49
	LR	−0.06	−0.87	−2.19		−1.77	−2.92	***−4.75***
	TPS_LR	−1.96	−3.36	***−5.53***		−2.97	***−4.71***	***−7.18***
	TPS2_LR	−2.54	***−5.12***	***−8.11***		−3.42	***−6.28***	***−9.82***
7%	TPS	−1.12	−1.13	−1.95		−0.29	−0.25	−0.83
	TPS2	−2.75	***−4.60***	***−7.18***		−0.83	−1.93	−3.83
	HR	−0.02	−0.12	2.48		2.65	3.67	7.05
	TPS_HR	−0.02	−0.12	2.48		2.65	3.67	7.05
	TPS2_HR	−1.48	−1.85	−2.48		2.28	3.43	5.71
	LR	−0.88	−1.87	−3.44		−3.38	***−4.84***	***−7.07***
	TPS_LR	−2.46	***−4.04***	***−6.38***		−3.96	***−6.01***	***−8.76***
	TPS2_LR	***−4.29***	***−7.44***	***−11.28***		***−4.84***	***−8.59***	***−13.40***

Grey cells = increase in CO_2e, Italicized numbers = CO_2e reduction of more than 4%.