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Natural gas scenarios in the U.S. power sector

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ABSTRACT

The United States power sector is being transformed by the recent rise in the availability and use of unconventional natural gas, specifically shale gas. That transformation has already produced some of the most significant changes in the operation of the portfolio of electricity generation since WWII. Further implications are likely. To that end, we present results from numerical modeling of different United States (U.S.) power sector futures. These futures assess questions affecting today's natural gas and electric power markets, including the impacts of: forthcoming EPA rules on power plants, decarbonization options such as a clean energy standard (CES), potential improvements in key generation technologies, expanded use of natural gas outside of the power generation sector, and higher costs for natural gas production—assumed to arise from more robust environmental and safety practices in the field. The simulations were done using the ReEDS model looking out to the year 2050. ReEDS is a capacity expansion model that determines the least-cost combination of generation options that fulfill a variety of user-defined constraints such as projected load, capacity reserve margins, emissions limitations, and operating lifetimes. The baseline scenario shows strong growth in natural gas generation, leading to a roughly 2.5-fold increase in gas demand by 2050. Many other scenarios also see strong growth in gas-fired generation, highlighting questions about portfolio diversity, climate change, and research and development prioritization.

1. Introduction

The United States power sector is being transformed by the recent rise in the availability and use of unconventional natural gas, specifically shale gas (Kargbo et al., 2010; Kerr, 2010; Rogers, 2011). That transformation has already produced some of the most significant changes in the operation of the portfolio of electricity generation since WWII (JISEA, 2013). Further implications are likely. To that end, we present results from numerical modeling of different United States (U.S.) power sector futures. These futures assess questions affecting today's natural gas and electric power markets, including the impacts of: decarbonization options such as a clean energy standard (CES), potential improvements in key generation technologies, expanded use of natural gas outside of the power generation sector, and higher costs for natural gas production—assumed to arise from more robust environmental and safety practices in the field. The modeling analysis presented here is not a prediction of how the U.S. electricity sector will evolve in the future—rather, it is an exercise to compare the relative impacts of different scenarios. The scenarios were generated using the Regional Energy Deployment System (ReEDS) model looking out to the year 2050. ReEDS is a capacity expansion model that determines the least-cost combination of generation options that fulfill a variety of user-defined constraints such as projected load, capacity reserve margins, emissions limitations, and operating lifetimes (Short et al., 2011).

This paper briefly presents results of two scenarios in addition to a reference scenario:

1. A *CES scenario* with carbon mitigation sufficient for the U.S. power sector to contribute its share in lowering emissions to a level that many scientists report is necessary to address the climate challenge (C2ES, 2011; IPCC, 2007): This simulates a CES similar to, but not identical to, that proposed by Senator Jeff Bingaman, but analyzes impacts through 2050 (EIA, 2012a).
2. A *Natural Gas Supply–Demand Variation scenario* for natural gas, aimed to simulate the impact of (1) steps taken to incrementally address environmental and safety concerns associated with unconventional gas production, and (2) significant growth in natural gas demand outside the power sector (dash-to-gas): In both cases, the incremental cost of securing natural gas for power generation results in different power sector futures over the long term.

a. *Assumptions and limitations*

Supply curves were developed to represent natural gas cost to the power sector and the response of this cost to increased power sector demand. The supply curves were developed based on linear regression analyses from multiple scenarios developed by the Energy Information

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Administration in the Annual Energy Outlook 2011 (EIA, 2011). [1](EIA, 2011). Annual Energy Outlook 2011 scenarios are projections out to the year 2035 and these results are extrapolated to 2050 for use in the ReEDS model. A separate supply curve was developed for each year to represent changes in projected supply and demand interactions as estimated in the multiple Annual Energy Outlook 2011 scenarios. The modeling team had already commenced work by the time the 2012 edition of the Annual Energy Outlook was released, so it could not take advantage of those newer data. The supply curves represent the price of fossil fuel to the power generators as a function of overall electric sector consumption of the fuel. In particular, as electric sector consumption increases, the marginal fossil fuel price to power generators (and all consumers of the fossil fuel) would increase. Within each year of the ReEDS optimization, the model sees this price response to demand through the linear supply curves. Three sets of supply curves were developed, representing different levels estimated ultimate recovery (EUR[2]) of natural gas. (Additional detail on these supply curves is also outlined in Appendix 1.)

Current renewable tax incentives and state renewable portfolio standards are represented in the ReEDS model. Tax incentives include the modified accelerated cost recovery system for tax depreciation, the production tax credit for utility-scale wind technologies, and the investment tax credit for solar and geothermal technologies.[3] The tax credits are assumed to expire at their legislative end date and not be renewed. In particular, the wind production tax credit was scheduled to expire at the end of 2012 (it has since been extended, although the analysis was conducted before that time), and the solar ITC declines from 30% to 10% in 2016. Although the solar and geothermal investment tax credits have no legislative end date, they are assumed to expire in 2030 as to not influence the long-term expansion decision of the model.

All scenarios presented here assume that 30 GW of coal-fired capacity will retire by 2025. ReEDS co-optimizes electricity transmission infrastructure development along with new generation capacity and determines when transmission and generation are required and tracks the costs associated with their deployment. It does not track the need to build new natural gas pipeline infrastructure so those costs are not included in this analysis. ReEDS is not designed to account for distributed generation; therefore, the penetration of distributed (residential and commercial) rooftop PV capacity was exogenously input into ReEDS from NREL's Solar Deployment Systems (SolarDS) model (Denholm et al., 2009). SolarDS is a market penetration model for commercial and residential rooftop PV, which takes as inputs rooftop PV technology costs, regional retail electricity rates, regional solar resource quality, and rooftop availability. In all cases, 85 GW of rooftop PV was assumed to come online by 2050. This assumption was based on some of the Renewable Electricity Futures (RE Futures) Report 80%-by-2050 renewable electricity scenarios (NREL, 2012). Other assumptions, including cost and performance data, are listed in Appendix 1 and discussed in the RE Futures study. More generally, ReEDS is an electric sector only model that requires exogenous specifications of other sectors and their interactions with the power sector. For example, electricity demand is exogenously defined in the scenarios.

2. Reference scenario

Three different baseline cases were evaluated in the Reference scenario:

- Baseline – Mid-estimated ultimate recovery (Mid-EUR) case, with average power demand growth and a moderate outlook for natural gas prices.
- Baseline – Low-EUR case reflecting the potential for more limited and hence more expensive natural gas.
- Baseline – Low-Demand case with Mid-EUR expectations. Low demand for electricity could be the result of continued economic stagnation (low gross domestic product (GDP) growth) or successful efforts to curb energy demand through energy efficiency, demand response, smart grid, and other programs to reduce the need for new electricity supply.

A Baseline – High-EUR case was not considered in this family in order to keep the number of results manageable. Throughout this study, the authors purposefully limit the number of reported sensitivities explored in most scenarios to examine the range of likely outcomes rather than overwhelm the reader with every possible situation. As noted previously, the Reference scenario is not a prediction of the future U.S. electricity mix per se, but instead serves as a point of comparison for the other scenarios. Each baseline case in the Reference scenario is summarized in Table 1.

Figs. 1 and 2 present the projected growth of electric generating capacity and generation for each of the three baseline cases. In the Baseline – Mid-EUR case, total capacity grows from roughly 1000 GW in 2010 to just over 1400 GW in 2050. While nuclear and coal capacities decrease as a result of net aged-based retirements (see Appendix 1), natural gas combined-cycle and natural gas combustion-turbine capacities nearly double with especially strong growth expected after 2030 when nuclear and coal retirements accelerate. On-shore wind capacity grows steadily from roughly 40 GW in 2010 to nearly 160 GW in 2050, representing approximately 3 GW of new additions each year on average over the period, a significant reduction from deployment in recent years. In all three baseline cases, oil and gas steam turbine capacity is nearly fully retired by roughly 2035 due to the assumed aged-based retirements. Nuclear capacity also declines in all three baseline cases beginning around 2030 as plants reach the end of their assumed operational lifetime and licensing arrangements, and no new plants are built due to uncompetitive economics. As noted above, rooftop PV is not endogenously calculated by ReEDS. Under the technology cost assumptions used, utility-scale PV showed more limited growth compared to natural gas and wind, reaching roughly 10 GW by 2030 and 20 GW by 2050.

The Baseline – Low-EUR case considers a future in which natural gas is less abundant, and thus more expensive, than the Baseline – Mid-EUR case. The primary impact in such a future is less natural gas capacity and more coal and wind. For example, in this baseline case, the cumulative

Table 1
Description of reference scenario.

Case name	Assumption for future electricity demand	Assumption for estimated ultimate recovery (EUR)
Baseline – Low-EUR	Standard growth(EIA 2010)	Low-level
Baseline – Mid-EUR	Standard growth(EIA 2010)	Mid-level
Baseline – Low-demand	Low growth (NREL 2012)	Mid-level

[1] (EIA, 2011). Annual Energy Outlook 2011 scenarios are projections out to the year 2035 and these results are extrapolated to 2050 for use in the ReEDS model. A separate supply curve was developed for each year to represent changes in projected supply and demand interactions as estimated in the multiple Annual Energy Outlook 2011 scenarios. The modeling team had already commenced work by the time the 2012 edition of the Annual Energy Outlook was released, so it could not take advantage of those newer data.

[2] EUR is the amount of natural gas (or petroleum) that analysts expect to be economically recovered from a reservoir over its full lifetime. Three potential measures of EUR are used throughout this study (High, Mid, and Low) to reflect the ranges of optimism and uncertainty over unconventional natural gas availability and price. High EUR assumes recovery that is 50% above the Mid-EUR case; Low EUR assumes recovery 50% below. These measures of EUR are based on the definitions provided in EIA, 2011.

[3] Detailed information on these tax incentives can be found on the Database of State Incentives for Renewables and Efficiency at: http://www.dsireusa.org/.

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Exhibit 1

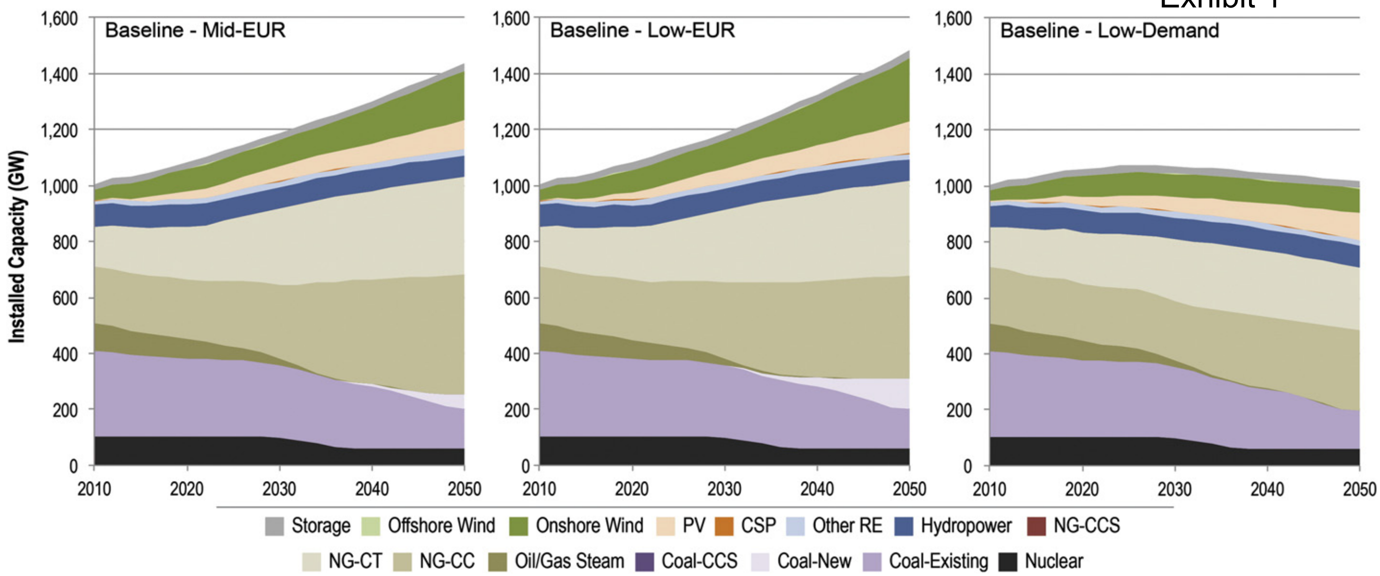

Fig. 1. Projected capacity in the Reference scenario, 2010–2050, for Baseline – Mid-EUR, Baseline – Low-EUR, and Baseline – Low-demand cases.

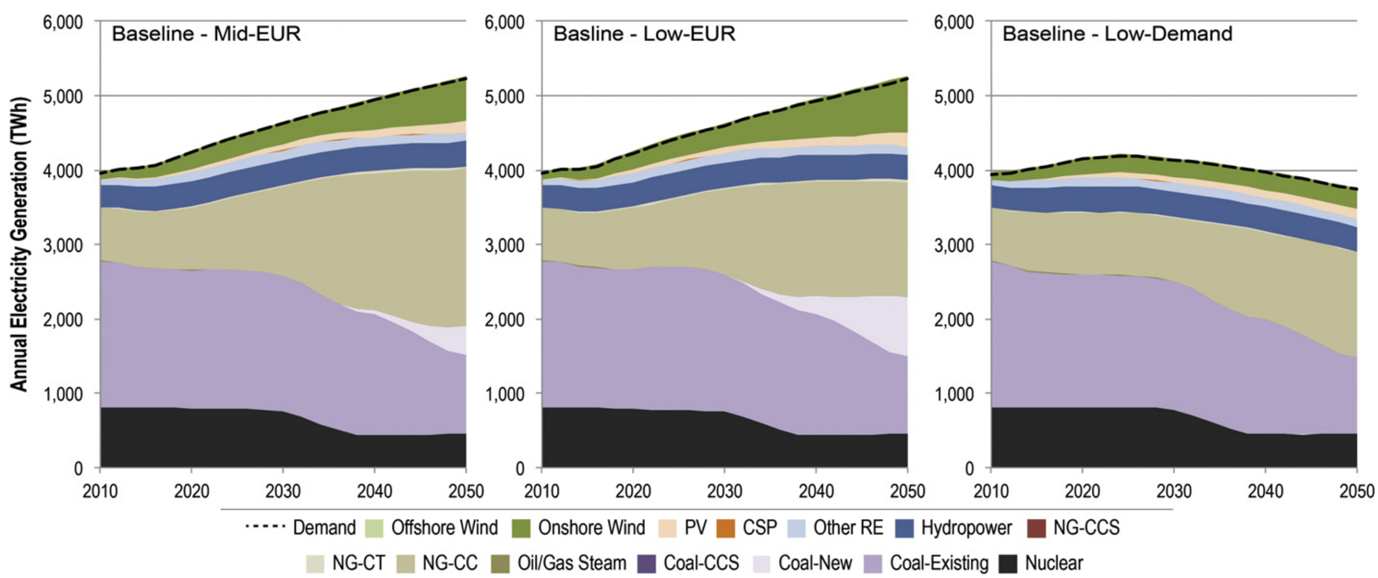

Fig. 2. Projected generation in Reference scenario, 2010–2050, for Baseline – Mid-EUR, Baseline – Low-EUR, and Baseline – Low-demand cases.

installed wind capacity reaches approximately 200 GW by 2050. In the final Baseline – Low-demand case, growth in natural gas capacity is affected the most, although wind and coal also see little-to-no growth. Considering the associated generation futures in these three baseline cases may be more instructive since capacity alone does not indicate how power plants are operated. Generation from natural gas combined-cycle plants doubles over the 40-year period, growing especially rapidly starting around 2030 because it is used to make up for the retired nuclear and coal generation (see Fig. 2). Generation from natural gas combustion-turbines is almost too small to see in these charts,[4] but plays an important role in meeting peak load needs. In the Baseline – Low-EUR case, new coal capacity is added and its generation plays a growing role in meeting power demand after 2030. This new coal is not needed in a low-demand future, and little new wind or other renewable energy generation is either.

Fig. 3 presents four key metrics for the baseline family of cases. First, natural gas consumption[5] rises 2.5-fold from 2010 to 2050 in the Baseline – Mid-EUR case, but still nearly doubles in the other two cases. Second, average real natural gas prices that generators pay are expected to nearly double by 2050 in the Baseline – Mid-EUR case,[6] while the Baseline – Low-EUR case would see higher prices throughout the period. A Baseline – Low-demand future will put far less pressure on natural gas prices because they peak at just over \$8/MMBtu[7] in 2050. Note the

[4] Generation from natural gas combustion turbine plants and other peaking units are likely underestimated by the ReEDS model due to its coarse temporal resolution. However, ReEDS does capture the peaking capacity needs and hence the growth in natural gas combustion turbine capacity shown in Fig. 1. ReEDS also treats oil/gas steam plants as peaking units, which inaccurately reflect the historical operation of some of these plants. This inaccuracy is not significant for the long-term analysis as most of the oil/gas steam fleet is assumed to be retired by the end of the study period.

[5] A Quad, or quadrillion Btu, is equivalent to approximately 1.055×10^{18} J (1.055 EJ).

[6] Prices to power generators are higher than wellhead prices by approximately \$1/MMBtu, but vary by region. (EIA, 2013).

[7] One million Btu (MMBtu) is equivalent to approximately 1.055×10^{9} J (1.055 GJ).

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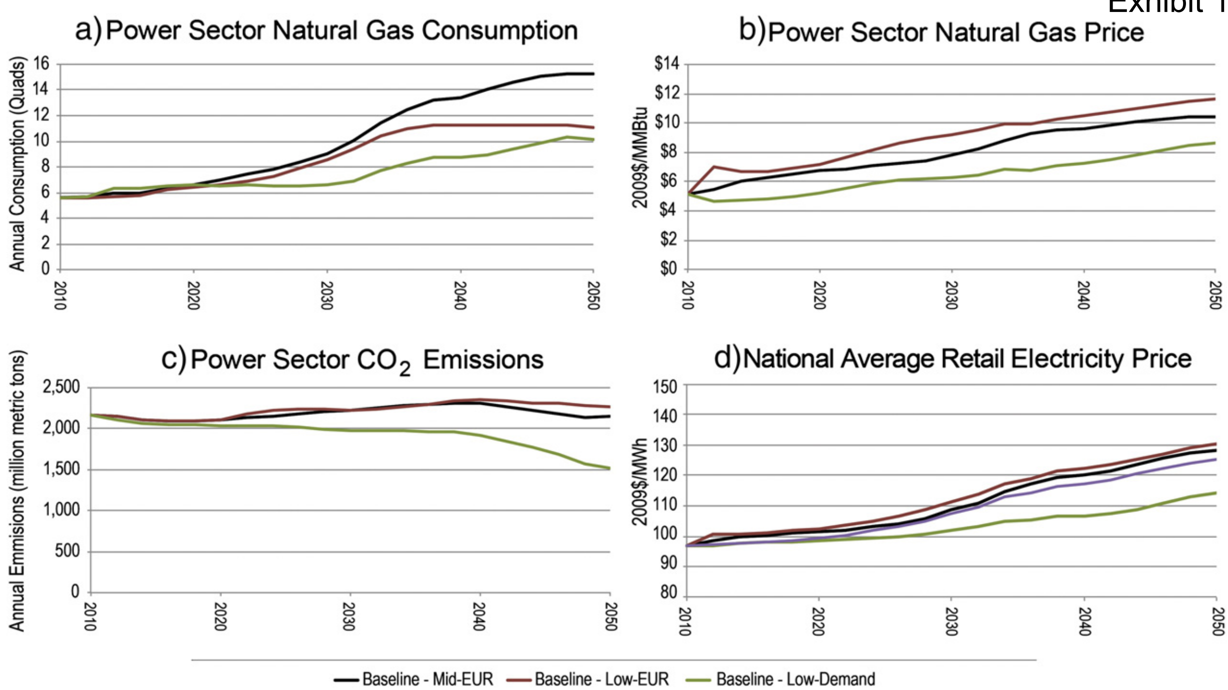

Fig. 3. Selected metrics for the Reference scenario, 2010–2050.

brief peak in the Low-EUR case in 2012; this results from initial calibration of the model and the rapid change that a Low-EUR future would entail compared to calibrated assumptions. Third, CO_2 emissions from the power sector are expected to remain relatively flat throughout the period. In the Baseline – Low-demand case, emissions decline as existing coal is replaced with natural gas. Finally, average real prices paid for retail electricity grow steadily through 2050 to roughly $130/MWh in the Baseline – Mid-EUR and Baseline – Low-EUR cases, but are approximately $15/MWh cheaper in the Baseline – Low-demand case.

An electric power future as envisioned in the Baseline – Mid-EUR case would include rapid growth in natural gas generation and less reliance on coal and nuclear power. In effect, natural gas and coal swap positions compared to their historical levels. One concern in such a future is that if volatility returns to natural gas prices after additional new capacity is built—and coal plants are already retired—the economy will be more directly exposed to fluctuating electricity prices (Frayer and Uludere, 2001; Komor and Bazilian, 2005). Careful consideration of the benefits and costs of such a shift in generation diversity is warranted. While CO_2 emissions do not grow significantly in such a future, they also do not begin to transition to a trajectory that many scientists believe is necessary to avoid dangerous impacts from climate change. GHG emission reductions of 60–80% by 2050 (compared to 2000 levels) are considered necessary by the Intergovernmental Panel on Climate Change (IPCC) in order to stabilize atmospheric concentrations of GHGs at a level that would reduce damaging impacts from a changing climate (IPCC, 2007). The Reference scenario results do not put the U.S. power sector on a trajectory to meet this target. A low power demand future, consistent with recently observed trends,[8] may provide greater generator diversity and prevent a potential over-reliance on natural gas. This Baseline – Low-demand case also has lower emissions and price impacts, although growth in low-carbon energy deployment slows significantly.

[8] Total net power generation in the U.S. peaked in 2007, according to EIA statistics, and has not yet returned to pre-recession levels (EIA, 2012c).

Table 2
Description of CES scenario.

Case name	Is carbon capture and sequestration available/economic?	Assumption for estimated ultimate recovery (EUR)
CES – High-EUR	Yes	High-level
CES – High-EUR, without CCS	No	High-level
CES – Low-EUR	Yes	Low-level

3. Clean energy standard scenario

After cap-and-trade legislation failed to pass the U.S. Senate in 2010, a CES became the preferred vehicle for those decision makers seeking to mitigate GHG emissions in the U.S. power sector.[9] A CES sets targets for the sale of qualifying clean energy generation over time, similar to a renewable portfolio standard,[10] but awards credits roughly based on the relative carbon weighting of emissions compared to standard coal-fired generation (EIA, 2012a; Michel, 2011). In this analysis, new nuclear and renewable generators receive 100% crediting because they have no burner-tip emissions; natural gas combined-cycle generation receives 50% crediting when used without CCS and 95% crediting with CCS; and coal receives 90% crediting, but only with CCS. This analysis follows the current CES legislation under discussion in Congress[11] calling for an 80% clean energy target in 2035, but extends the target to reach 95% by 2050.

Full life cycle GHG emission values could be used in the CES crediting rather than the current burner-tip estimates to provide a more representative picture of climate impacts. However, current understanding

[9] Three Senate leaders have put forth CES legislation since then: Senator Lindsay Graham (SC), Senator Dick Lugar (IN), and Senator Jeff Bingaman (NM).

[10] For more background on renewable portfolio standards and clean energy standards, see (C2ES, 2012).

[11] On March 1, 2012, Senator Jeff Bingaman introduced the Clean Energy Standard Act of 2012. More information on the bill is available at: http://www.energy.senate.gov/public/index.cfm/democratic-news?ID=67e21415-e501-42c3-a1fb-c0768242a2aa.

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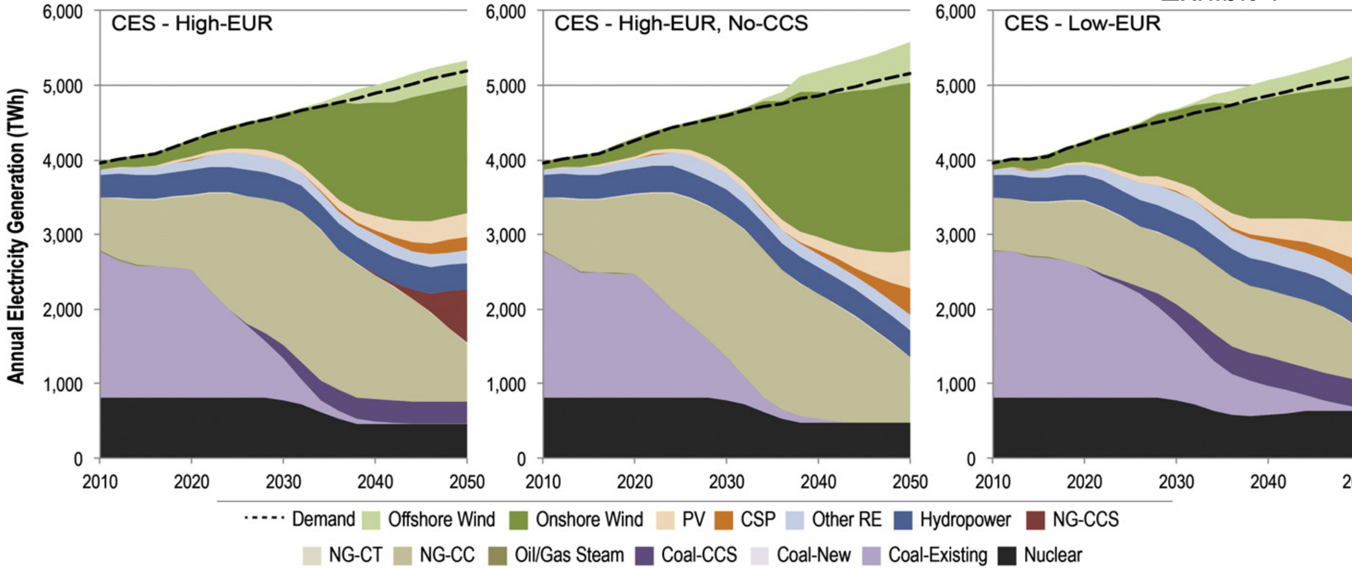

Fig. 4. Projected generation in CES scenario, 2010–2050 for CES – High-EUR, CES – High-EUR, without CCS; and CES – Low-EUR cases.

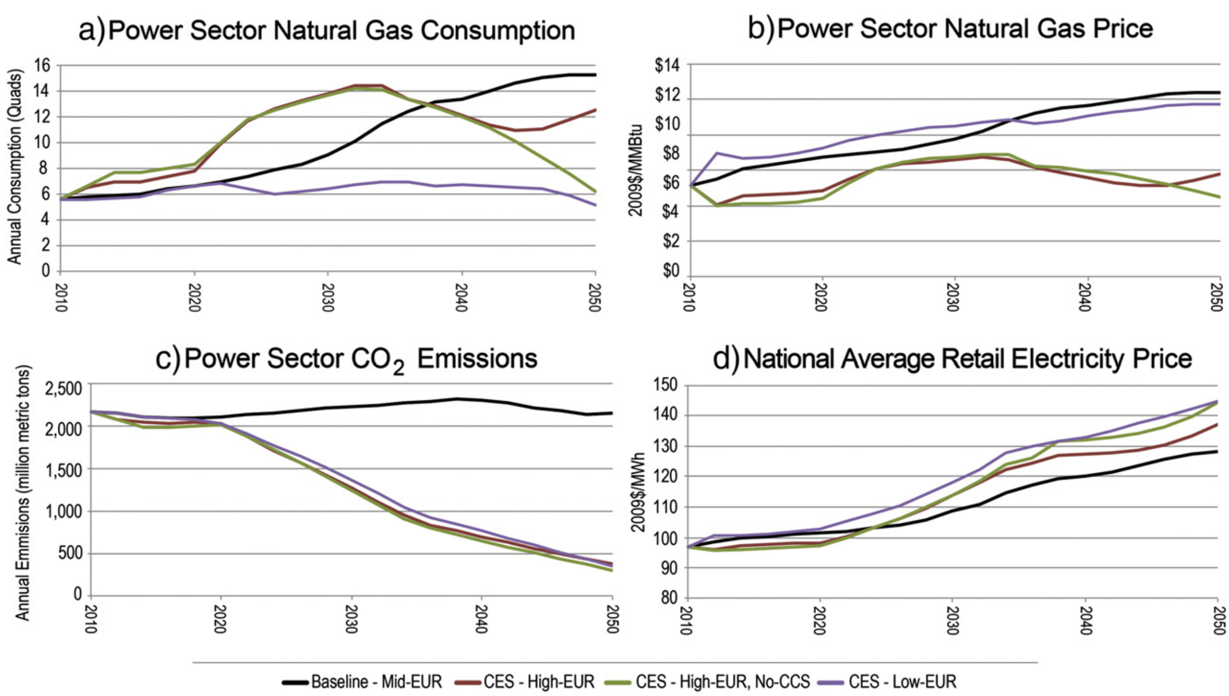

Fig. 5. Selected metrics for the CES scenario, 2010–2050.

of the full life cycle emissions of unconventional gas is not significantly different from the values noted above, so this analysis does not attempt to use them (Burnham et al., 2012; Weber and Clavin, 2012). As additional information becomes available, follow-on research could evaluate the impacts of different crediting values on the long-run evolution of the U.S. power sector.

Three separate CES cases are considered here:

- CES – High-EUR case.
- CES – High-EUR case where CCS is not available, either for technical, economic, or social reasons.
- CES – Low-EUR case.

Table 2 summarizes the three cases evaluated in the CES scenario.

Fig. 4 presents the impacts of the three CES cases on generation through 2050. In the early years before 2030, natural gas replacing coal is the primary contributor to meeting the rising CES targets. Beginning around 2030, however, natural gas is no longer able to contribute to meeting the target without CCS since it receives only 50% crediting toward the target. Instead, coal with CCS, wind, and natural gas with CCS are the next cheapest options in the CES – High-EUR case. If CCS is not available (CES – without CCS), wind generation is the next cheapest alternative to take its place. In such a case, renewable energy sources contribute approximately 80% of total generation by 2050.[12] Note that supply is higher than demand beginning around 2030 in most cases because increasing amounts of variable renewable generation are curtailed.

[12] NREL recently published the RE Futures study that evaluates many of the technical issues and challenges of operating the grid with such high percentages of renewable energy. See NREL (2012) for more detail.

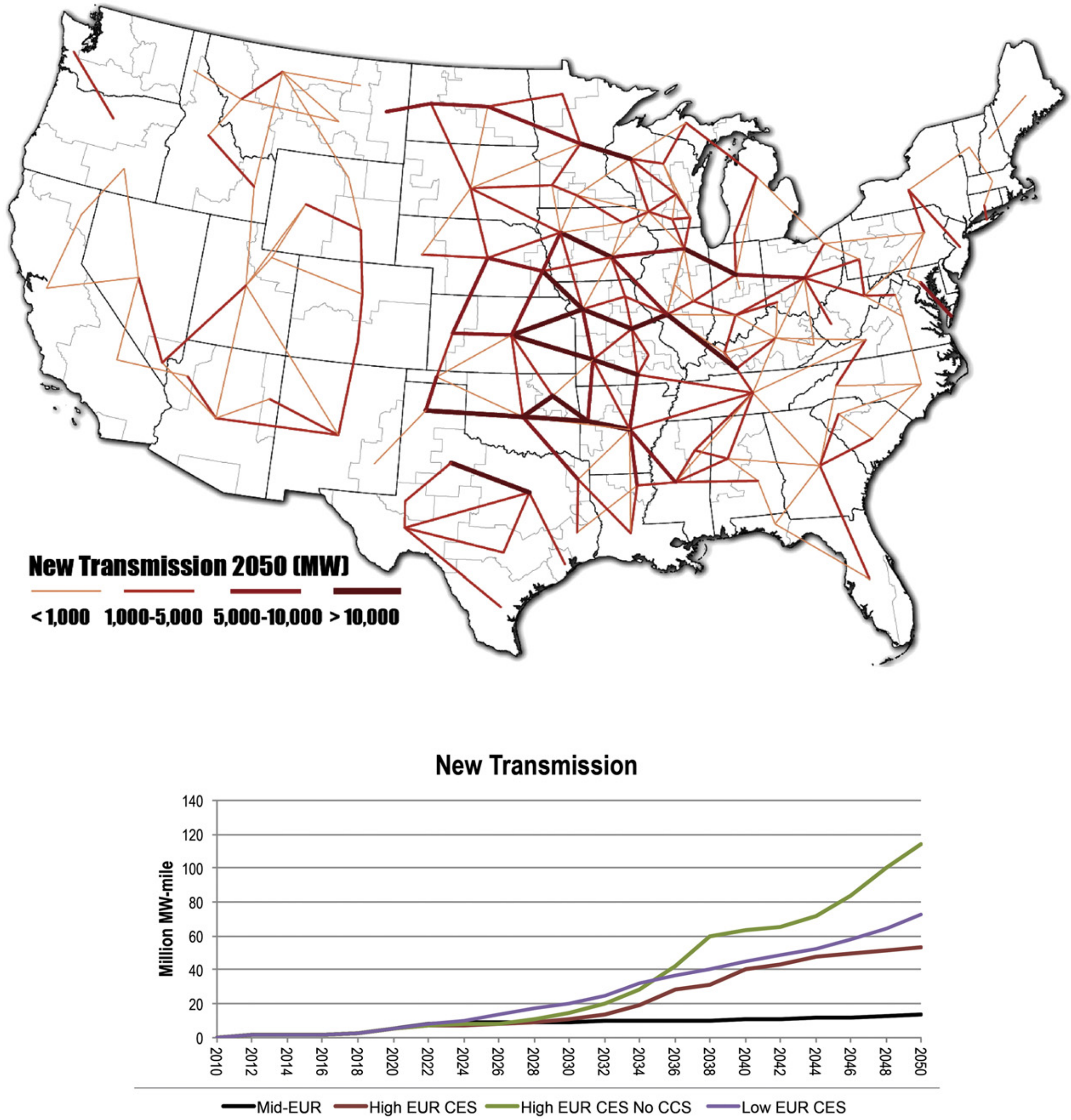

Fig. 6. Map of new transmission required by 2050 in the CES – High-EUR case, and measures of new transmission needed in all cases, 2010–2050.

A CES power future with more costly natural gas (CES – Low-EUR) would result in less natural gas generation, more solar and wind, and reliance on coal CCS rather than gas CCS compared to the CES – High-EUR case (Fig. 5). The amount of natural gas used in the CES scenario varies significantly by case, as shown in Fig. 5. In all cases, however, it peaks around 2030, and prices remain lower than the Baseline – Mid-EUR case through 2050. Power sector gas demand temporarily falls after 2030 in the CES – High-EUR case, but begins to climb again around 2040 as natural gas CCS becomes an economic contributor to the CES target. When CCS is not available, natural gas consumption continues to decline and is back at 2010 levels by 2050. In the CES – Low-EUR case, natural gas usage remains muted throughout the scenario lifetime as other options meet the target more economically. Average real electricity prices would increase compared to the Baseline – Mid-EUR case beginning in roughly 2020 and settle at levels between 6% and 12% higher by 2050. By 2050, CO_2 emissions from the U.S. power sector decline by more than 80% in all CES cases compared to the baseline. Coal generation without CCS has disappeared by that time in all cases. The power sector would be on a trajectory in all CES cases to achieve that sector's contribution to carbon mitigation

Table 3
Description of natural gas supply and demand variations scenario.

Case name	Focus	Assumption for estimated ultimate recovery
Natural gas supply cost variations	Evaluate impact on power sector as incremental natural gas production costs increase from $0.50/MMBtu to $2/MMBtu	Mid-level
Natural gas demand variations (dash-to-gas)	Evaluate impact to power sector as natural gas demand in other sectors increases by 12 bcf/d[a] by 2026	High-level

[a] A billion cubic feet of natural gas per day (bcf/d) is equivalent to approximately 28.32 million cubic meters of natural gas per day (mcm/d).

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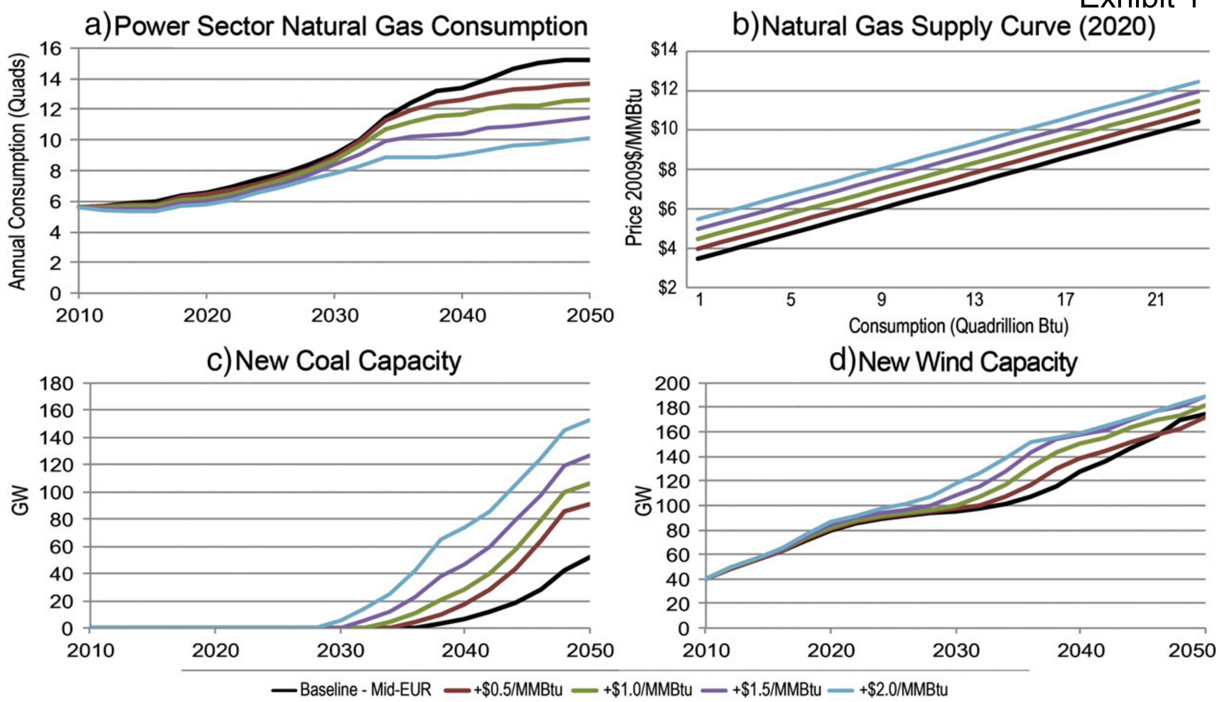

Fig. 7. Selected metrics for the natural gas supply cost variation case, 2010–2050.

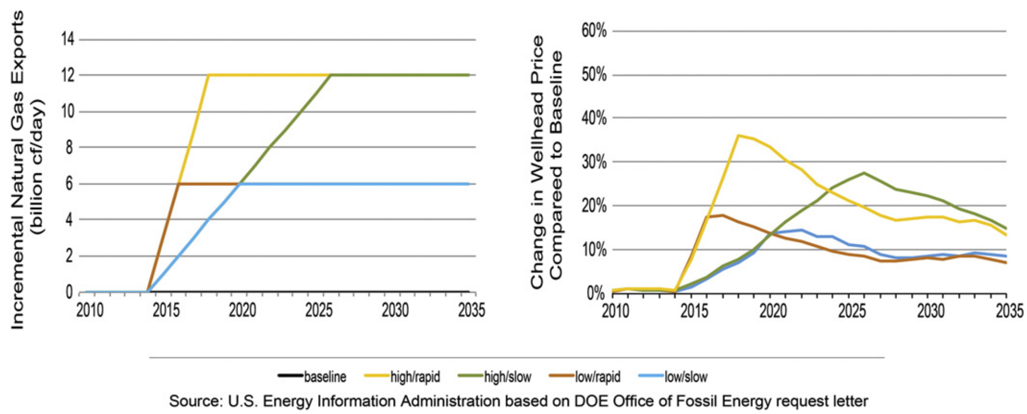

Fig. 8. EIA LNG export scenarios and their projected impacts on domestic natural gas prices, 2010–2035.

commensurate with levels the IPCC deems necessary to stabilize atmospheric concentrations of greenhouse gases (IPCC, 2007) at a level that could avoid some of the dangerous aspects of climate change.[13]

Because the CES cases project a very large build-out of wind power, ReEDS tracks the amount of new transmission lines needed to deliver power from where it is generated to where it is used. The estimated costs of building this new transmission infrastructure are included in the capacity analysis. Fig. 6 presents a geospatial map of where new transmission lines would be required through 2050. The vast majority of this new wind generation would be constructed in the Midwestern states for use throughout the Eastern Interconnect. Smaller quantities would be built in the Western and Electric Reliability Council of Texas (ERCOT) Interconnects. The greatest amount of transmission is needed when CCS is not available, and wind must play an even larger role. In this case, more than twice the amount of transmission, as measured in million megawatt-miles of capacity, would be needed compared to the CES – High-EUR case in 2050 (Fig. 6). Note that the constraints in ReEDS require planning reserve margins to be met and additional operating reserves for variable wind and PV generation. Additional costs that these requirements incur are included in the national average retail electricity prices based on the generation and transmission cost assumptions presented in the appendix and in Short et al. (2011). While ReEDS captures the integration challenges for variable technologies at a high level, further work, including detailed dispatch modeling, is needed to better evaluate the operational impacts of high renewable scenarios.

The CES options analyzed here indicate that the U.S. power sector could achieve significant decarbonization by 2050 at relatively modest economic costs, although barriers to building sufficient transmission may be formidable (NREL,). Approximately six times more transmission is needed in the CES – without CCS case than in the Baseline – Mid-EUR case by 2050, and three times as much in the CES – High-EUR case. A greater diversity of power generation is achieved when CCS is available

[13] The power sector's contribution to GHG mitigation noted here is assumed to be the same percentage reduction as that of the entire economy (i.e., 80%).

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Table 4
Non-power sector natural gas demand assumptions in the natural gas demand variations case.

	2010	2020	2030	2040	2050
(Billions of cubic feet per day)					
LNG exports	0	5.0	7.3	5.0	0
Vehicles[a]	0	1.5	2.7	3.0	0
Industry/other	0	1.5	2.0	1.5	0
Subtotal	0	8.0	12.0	9.5	0

[a] These estimates for compressed natural gas use in vehicles are proposed by Wellkamp and Weiss (2010).

and economic for use on coal or gas plants. Heavy reliance on the need for transmission is also lessened when CCS is available. Additional research should be considered to evaluate potential natural gas infrastructure barriers in such a scenario of high variable renewable energy generation. In all CES cases, flexible natural gas generators help enable a power generation mix that relies heavily on variable renewable technologies such as wind and solar.

4. Natural gas supply and demand variations scenario

Two separate cases are considered here:

- *Natural gas supply cost variations*: Variations in natural gas supply costs that could result from either additional state or federal regulations, or more costly field practices that suppliers follow in order to better protect the environment. The impact of these incremental natural gas costs on the power sector over the longer-term is simulated using ReEDS. This analysis covers a broad range of potential incremental costs associated with producing natural gas in a way that commands stronger public support yet is still feasible for producers and consumers. We do not arrive at an estimated incremental cost impact of following these practices in $/MMBtu terms, but instead use ranges beginning at an incremental $0.50/MMBTu and ending at $2.0/MMBtu above the baseline cost. The values used here could be helpful to those who know what their incremental costs are, or to a broader audience in the future when cost estimates are available.
- *Natural gas demand variations*: Variations in demand for natural gas outside the power sector that could result from a "dash-to-gas" across the larger economy. This dash-to-gas could occur in the export of LNG, greater use of natural gas in vehicles (either as compressed natural gas throughout the fleet, or as LNG in heavy duty vehicles). Under a dash-to-gas case, natural gas prices rise due to the greater demand and make it more expensive for power generators to utilize natural gas generation.

Table 3 summarizes key assumptions used in the supply and demand variations scenario.

4.1. Natural gas supply cost variations

Fig. 7 illustrates adjustments to the natural gas supply curves that could result when additional measures are taken to protect the environment when producing natural gas. These measures could be the result of new regulations or different practices in the field (Rahm, 2011). Examples of these added costs might include the following:

- Activities such as recycling or treating a greater quantity of water supply used in hydraulic fracturing.
- Minimizing the amount of methane that is released to the atmosphere before, during and after fracturing a well.
- Casing wells in a more robust and consistent way.
- Practicing more robust cement bond logging techniques.
- Substituting more environmentally benign options for traditional hydraulic fracturing additives.

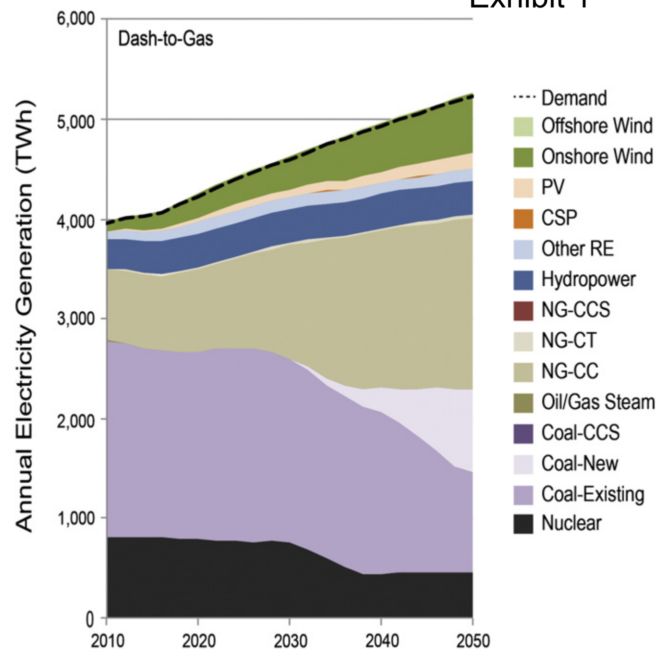

Fig. 9. Power generation mix in the dash-to-gas case.

- Engaging local stakeholders in dialogs in advance of drilling to ensure their concerns are heard and addressed.
- Enforcing larger set-backs from potentially sensitive communities.
- Disposing of or treating flowback water in improved ways.

Few publicly available studies estimate what these specific costs might be and how they vary by region.[14] The International Energy Agency (IEA) recently published its "Golden Rules for a Golden Age of Natural Gas" (IEA, 2012), a statement of 22 steps that should be considered when producing natural gas. The IEA report stated that, "We estimate that applying the Golden Rules could increase the overall financial cost of development a typical shale-gas well by an estimated 7%"[sic] (IEA, 2012). Therefore, if it normally costs $3.50/MMBtu to develop shale gas, the Golden Rules cost would be approximately $0.25/MMBtu higher at a typical play. This is nominally consistent with, although lower than, recent estimates of the costs of complying with pending federal rules, including the new EPA air regulations for oil and gas producers, which might cost between $0.32/MMBtu and $0.78/MMBtu, according to one analyst (Book, 2012). Informal consultations associated with this study suggest that maximizing water recycling might result in an additional $0.25/MMBtu in added costs. Although this study did not quantify the additional costs that could result from enhanced environmental and safety practices in the field, it is clear that these costs will vary by region and that many additional safeguards could be practiced at less than an incremental cost of $1/MMBtu. A 2009 study funded by the American Petroleum Institute anticipated much higher costs if new federal regulations were imposed on natural gas producers (IHS, 2009).

To assess the potential impacts of these incremental supply costs, this study considers a range of additional costs starting from $0.50/MMBtu and going up to $2/MMBtu in increments of $0.50/MMBtu, and evaluates the impacts on the long-range evolution of the power sector when these costs are applied. Fig. 7 shows the reduction in natural gas use in the power sector as incremental costs are increasingly applied. At the upper limit, natural gas consumption for power generation declines from roughly 15 quads[15] in the Baseline—Mid-EUR case to 10 quads (incremental $2/

[14] The authors are not aware of any peer-reviewed studies that estimate the marginal cost of new regulations or improved field practices noted here.
[15] To roughly convert from quads to bcf/day, multiply by 2.6. Thus, 15 quads per year equal approximately 38.5 bcf/day.

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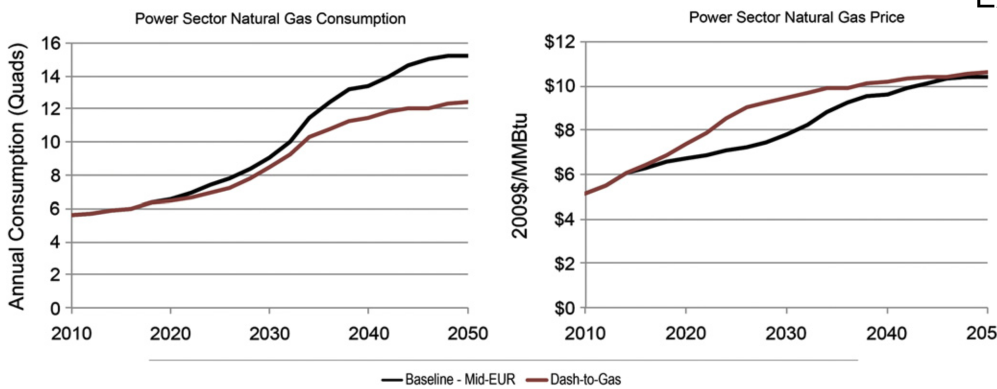

Fig. 10. Selected metrics for the dash-to-gas case, 2010–2050.

MMBtu added) by 2050. With a \$0.50/MMBtu added cost of gas production, the long-term impacts are far more modest resulting in a reduction of gas use for power generation in 2050 of less than 2 quads. Coal, and to a lesser extent, wind, replaces the generation that the more expensive gas loses. Other impacts associated with these assumed incremental costs appear relatively modest.

Many additional measures could be taken by producers to address the real and perceived risks associated with unconventional natural gas production at a modest impact to the evolution of the power sector. If total costs from a long list of potential practices reached \$1.00/MMBtu, natural gas usage in the 2050 power sector might be expected to decline from 2.5 times the 2010 level in the baseline to 2 times in the supply variation case. Costs associated with ensuring stronger public support of unconventional gas and oil production would vary by region and producer. Technologies associated with unconventional natural gas production are under rapid development so the cost impacts will be dynamically changing. Follow-on research should attempt to gather additional data from producers to better estimate what the real cost would be of addressing social license to operate issues on a basin-by-basin level. The question for industry then might be: are these added costs worth absorbing, and an acceptable price to pay, to ensure both greater public and utility-sector confidence in the production practice over the longer term?

4.2. Natural gas demand variations (dash-to-gas)

The natural gas demand variations case considers the impact to potential expansion of natural gas generation if a significant shift to natural gas occurs in other sectors of the economy. Specifically, it looks at the combined potential of new LNG exports, natural gas vehicle deployment (both compressed natural gas and LNG in heavy-duty trucking), and use in industrial and chemical applications and any other sector that in aggregate reaches 12 bcf/day by 2026.

A growing number of studies analyze the impact of LNG exports on domestic natural gas prices (Deloitte, 2011; Ebinger et al., 2012; EIA, 2012b; Pickering, 2010).[16] Estimates vary considerably depending on methodology used, location, and assumptions about overall gas availability. The case examined here uses the methodology in the EIA LNG exports scenario as a basis for the full economy "dash-to-gas."[17] Thus, it takes the "high and slow" EIA-derived price impact of exporting 12 bcf/day of LNG by 2026 and uses it to represent the impact of a combined 12 bcf/day in the total economy, distributed among LNG exports, vehicle use, industrial use, and any other applications (See Fig. 8 and Table 4).

In the natural gas demand variations (dash-to-gas) case where gas prices rise by a maximum of 29% above the Reference scenario value in 2026 before re-equilibrating, the power sector mix is similar to the Baseline – Low-EUR case (compare Fig. 9 with Fig. 2), although still slightly more reliant on natural gas generation. A dash-to-gas future, then, would restrict gas generation to less than doubling by 2050 compared to the 2010 level. The larger macroeconomic impacts associated with this future were not evaluated; however, overall gas demand declines by approximately 3 quads by 2050 compared to the baseline.

The price of natural gas for power generators rises by a maximum of \$2/MMBtu above the baseline value in the early 2020s before returning to the baseline level in 2050 when the other sectors are assumed to terminate their extra reliance on natural gas (see Fig. 10).

Understanding the price impacts of a dash-to-gas case is still poorly characterized due to the newness of the recent change in natural gas supply outlook. Based on currently available estimates, a fairly strong dash-to-gas in other sectors of the economy would have a visible, although still marginal, impact on the evolution of the electric power sector, with natural gas use declining somewhat due to the higher prices and other forms of generation increasing to take its place. As additional experience and estimates of this elasticity become available, follow-on research should re-examine the impacts.

5. Conclusions

The role of natural gas in the U.S. power sector is sensitive to assumptions about EUR and future policies. More research is needed to better understand how much gas will ultimately be recovered from unconventional plays, and at what price.

The CES modeling results indicate that substantial reductions in CO_2 emissions are achievable at modest cost, although transmission barriers could stand in the way. Natural gas is the most cost-effective contributor to meeting CES targets through roughly 2030, but loses that status to wind, at least temporarily if CCS becomes a viable option. In all sensitivities, renewable generation contributes to half or more of total power demand by 2050. When CCS is not available under a CES, generation options decline, the need for new transmission expands significantly, and the power mix becomes less diverse. CCS is therefore an important option for a low-carbon power sector, but may not be essential.

Increased costs associated with potential changes in natural gas producer field practices were evaluated over a fairly broad range. If these costs turn out to be less than an incremental \$1/MMBtu, the long-term impact on natural gas in the power sector is not significantly different from the baseline conclusions: gas demand for power generation declines by approximately 17% while CO_2 emissions increase marginally. Whether these additional costs associated

[16] The authors are not aware of any peer reviewed studies that estimate the impact of LNG exports on the domestic economy.

[17] The upper limits (i.e., high/rapid scenario) of the EIA study have been criticized by some (Ebinger et al., 2012) as too extreme and not representative of how LNG exports might really occur. Although the study in this report uses the second-most extreme (high/slow) LNG export scenario considered by the EIA, the scenario is constructed to capture a wider range of potential natural gas end-uses than just LNG exports.

with protecting the environment, improving safety, and commanding public confidence are worthwhile to society and gas producers would be an important question for follow-on research and discussion.

While natural gas appears plentiful and at historically low price levels for the near term future, decision makers may want to pay special attention to generation diversity going forward, especially given the long lived nature of power generation assets. A major shift to natural gas generation, along with other increased demands and exports, may lead to a substantial rise in natural gas prices due to, for example, mischaracterizations of EUR, a failure to earn the social license to operate, or some other reason that may currently be considered "unlikely". Continuing research, development, and deployment over a wide variety of generation and gas production options can help prevent such an outcome. It would also provide greater flexibility in addressing the threat of climate change.

Appendix 1. Assumptions used in ReEDS

What is ReEDS?[18]

The Regional Energy Deployment System is an optimization model used to assess the deployment of electric power generation technologies and transmission infrastructure throughout the contiguous United States into the future. The model, developed by NREL, is designed to analyze critical energy issues in the electric sector, especially with respect to the effect of potential energy policies such as clean energy and renewable energy standards or carbon restrictions.

ReEDS provides a detailed treatment of electricity-generating and electrical storage technologies, and specifically addresses a variety of issues related to renewable energy technologies, including accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal generation profiles, variability of wind and solar power, and the influence of variability on the reliability of the electrical grid. ReEDS addresses these issues through a highly discretized regional structure, explicit statistical treatment of the variability in wind and solar output over time, and consideration of ancillary services requirements and costs.

Qualitative model description

To assess competition among the many electricity generation, storage, and transmission options throughout the contiguous United States, ReEDS chooses the cost-optimal mix of technologies that meet all regional electric power demand requirements, based on grid reliability (reserve) requirements, technology resource constraints, and policy constraints. This cost minimization routine is sequentially performed for each of 20 2-year periods from 2010 to 2050. The major outputs of ReEDS include the amount of generator capacity and annual generation from each technology, storage capacity expansion, transmission capacity expansion, total electric sector costs, electricity price, fuel prices, and CO_2 emissions. Time in ReEDS is subdivided within each 2-year period, with each year divided into four seasons with a representative day for each season, which is further divided into four diurnal time slices. Also, there is one additional summer-peak time slice. These 17 annual time slices enable ReEDS to capture the intricacies of meeting electric loads that vary throughout the day and year—with both conventional and renewable generators.

Although ReEDS includes all major generator types, it has been designed primarily to address the market issues that are of the greatest significance to renewable energy technologies. As a result, renewable and carbon-free energy technologies and barriers to their adoption are a focus. Diffuse resources such as wind and solar power come with concerns that conventional dispatchable power plants do not have, particularly regarding transmission and variability. The ReEDS model examines these issues primarily by using a much greater level of geographic disaggregation than do other long-term large-scale capacity expansion models. ReEDS uses 356 different resource regions in the continental United States. These 356 resource supply regions are grouped into four levels of larger regional groupings—balancing areas, reserve-sharing groups, North American Electric Reliability Council regions,[19] and interconnects. States are also represented for the inclusion of state policies.

Many of the data inputs in ReEDS are tied to these regions and derived from a detailed GIS model/database of the wind and solar resource, transmission grid, and existing plant data. The geographic disaggregation of renewable resources enables ReEDS to calculate transmission distances as well as the benefits of dispersed wind farms, PV arrays, or CSP plants supplying power to a demand region. Offshore wind is distinguished from onshore wind both in terms of technology cost/performance and resources. The wind and CSP supply curves are subdivided into five resource classes based on the quality of the resource—strength and dependability of wind or solar isolation. Regarding resource variability and grid reliability, ReEDS also allows electric and thermal storage systems to be built and used for load shifting, resource firming, and ancillary services. Four varieties of storage are supported: pumped hydropower, batteries, compressed air energy storage, and thermal storage in buildings.

Along with wind and solar power data, ReEDS provides supply curves for hydropower, biomass, and geothermal resources in each of the 134 balancing areas. The geothermal and hydropower supply curves are in megawatts of recoverable capacity and the biomass supply curve is in million British thermal units of annual feedstock production. In addition, other carbon-reducing options are considered. Nuclear power is an option, as is CCS on some coal and natural gas plants. CCS is treated simply, with only an additional capital cost for new coal and gas-fired power plants for the extra equipment and an efficiency penalty to account for the parasitic loads of the separation and sequestration process. Also, a limited set of existing coal plants can choose to retrofit to CCS for an associated cost as well as a performance penalty. The major conventional electricity-generating technologies considered in ReEDS include hydropower, simple- and combined-cycle natural gas, several varieties of coal, oil/gas steam, and nuclear. These technologies are characterized in ReEDS by the following:

- Capital cost ($/MW)
- Fixed and variable operating costs ($/MWh)
- Fuel costs ($/MMBtu)
- Heat rate (MMBtu/MWh)
- Construction period (years)
- Equipment lifetime (years)
- Financing costs (such as nominal interest rate, loan period, debt fraction, debt-service-coverage ratio)
- Tax credits (investment or production)
- Minimum turndown ratio (%)
- Quick-start capability and cost (%, $/MW)
- Spinning reserve capability
- Planned and unplanned outage rates (%)

[18] "What is ReEDS?" is taken from the 2011 detailed documentation for the ReEDS model. Short, W. et al., Regional Energy Deployment System (ReEDS). NREL Technical report NREL/TP-6A20-46534, August 2011. http://www.nrel.gov/analysis/reeds/.

[19] North American Electric Reliability Corporation, October 2010. "2010 Long-Term Reliability Assessment." http://www.nerc.com/files/2010%20LTRA.pdf. Accessed November 2, 2011.

Renewable and storage technologies are governed by similar parameters—accounting for fundamental differences. For instance, heat rate is replaced with round-trip-efficiency in pure storage technologies, and the dispatchability parameters, such as fuel cost, heat rate, turndown ratio, and operating reserve capability, are not used for non-dispatchable wind and solar technologies. These variable generation technologies are further characterized by changes in generation levels over the course of a year.

The model includes consideration of distinguishing characteristics of each conventional generating technology. There are several types of coal-fired power plants within ReEDS, including pulverized coal with and without sulfur dioxide scrubbers, advanced pulverized coal, integrated gasification combined cycle, biomass co-firing, and integrated gasification combined cycle with CCS options. Coal plant generation is discouraged from daily cycling via a cost penalty, which represents a combination of additional fuel burnt, heat rate drop off, and mechanical wear-and-tear. Natural gas plants represented in ReEDS include simple-cycle combustion turbines, combined cycle plants, and combined cycle with CCS plants. Combined-cycle natural gas plants can provide some spinning reserve and quick-start capability, and simple-cycle gas plants can be used cheaply and easily for quick-start power. Nuclear power is represented as one technology in ReEDS, and is considered to be baseload.

Retirement of conventional generation and hydropower can be modeled through exogenous specification of planned retirements or based on usage characteristics of the plants. All retiring non-hydro renewable plants are assumed to be refurbished or replaced immediately because the site is already developed and has transmission access and other infrastructure.

ReEDS tracks emissions of carbon and sulfur dioxide from both generators and storage technologies. Caps can be imposed at the national level for these emissions, and constraints can also be applied to impose caps at state or regional levels. There is another option of applying a carbon tax instead of a cap; the tax level and ramp-in pattern can be defined exogenously. In addition, ReEDS can impose clean energy or renewable energy standards at the regional or national level.

Annual electric loads and fuel price supply curves are exogenously specified to define the system boundaries for each period of the optimization. To allow for the evaluation of scenarios that might depart significantly from the Reference scenario, price elasticity of demand is integrated into the model: the exogenously defined demand projection can be adjusted up or down based on a comparison of an estimated business-as-usual electricity price path and a calculation of electricity price within the model for each of the 20 2-year periods. However, elasticities are assumed to only have a minor effect in the present scenarios. For example, the noticeable difference in 2050 electricity prices between the Baseline (mid-EUR) and CES (low-EUR) scenarios ($15/MWh) resulted in a difference of only 100 TWh (2% of total demand) in annual 2050 electricity demand.

ReEDS is an electric sector model that relies on exogenous specification of the greater economy. In addition to exogenously defined electricity demand, ReEDS relies implicitly on exogenous assumptions about fossil fuel supply and demand interactions in other sectors. In particular, for coal and natural gas pricing, supply curves based on the Annual Energy Outlook (AEO) scenarios[20] have been developed and used in ReEDS. The price and demand dynamics from other non-electric sector consumers and producers are embedded within the AEO scenarios. For coal and natural gas pricing, supply curves based on the Annual Energy Outlook[21] have been developed and used in ReEDS.

Natural gas supply curve background and development

The EIA's Annual Energy Outlook 2011 has two specific scenarios that attempt to model the effects of high or low abundance of natural gas supply, High-EUR and Low-EUR. The High-EUR scenario increases the total unproved technically recoverable shale gas resource from 827 Tcf in the Mid-EUR baseline scenario to 1230 Tcf. In addition, the ultimate recovery per shale gas well is 50% higher than in the baseline scenario. Low-EUR reduces recoverable shale gas resource to 423 Tcf and 50% lower ultimate recovery per shale gas well than in the Mid-EUR baseline scenario.

The author's employed as a statistical technique, regression analysis, to isolate a relationship between natural gas prices and quantity in different EUR scenarios resulting from AEO modeling.[22] Deriving the coefficients for this study relied on assuming a linear regression model and employing an ordinary least squares method. Linear regression is a statistical technique that examines the relationship between one dependent variable (Y) and multiple explanatory variables, or regressors (X). The estimated coefficients represent the marginal impact of a 1-unit change in each independent variable on Y. Linear regression is typically used in coefficient estimation or forecasting.[23] In this case, we used linear regression to extrapolate the relationship between modeled natural gas price and consumption under different natural gas scenarios.

This study estimated electric sector price based on the following predictors: electric sector consumption, economy-wide consumption, year (2012–2035), and the natural gas scenario case.[24] Each electric sector price for each of the Annual Energy Outlook scenarios from 2012 to 2035 was treated as an independent observation used to estimate coefficients in the following model: [25]

$$
\begin{aligned}
&\mathit{Electric\,sector\,price}_i \\
&\quad = \beta_0 + \beta_1 * \mathit{Electric\,sector\,consumption}_i + \beta_2 \\
&\quad * \mathit{Economy{-}wide\,consumption}_i \\
&\quad + \sum_{j=1}^{12} \beta_j * \mathit{Year} + \sum_{k=1}^{4} \beta_k * \mathit{Natural\,gas\,scenario} + \varepsilon_i
\end{aligned}
$$

where i is a given scenario-year combination. Observations that occurred in High-EUR and Low-EUR were coded accordingly, creating two additional intercept shifter “dummy” variables. The year, rather than coded as continuous, was coded as a dummy variable to capture specific year effects, as well as intertemporal dependencies (cumulative consumption). To account for the predictor influence of economy-wide consumption, the average value for the year and the scenario for each data point were multiplied by β_2 (the derived electric sector consumption coefficient). As a result, the intercept varied by year and by scenario, while the slope remained the same across year and scenario. The intercept and shifter for the years 2036–2050 were held constant with model results in 2035.

[20] Annual Energy Outlook 2011. DOE/EIA-0383. Washington, DC: U.S. Energy Information Administration.

[21] Annual Energy Outlook 2011. DOE/EIA-0383. Washington, DC: U.S. Energy Information Administration.

[22] AEO estimates are derived from the National Energy Modeling System (NEMS), which is organized as a modular system. Natural gas supply is captured within the “Oil and Gas Supply Module,” so there is no direct input supply curve the authors could incorporate for this study.

[23] Damodar, Gujarati. Basic Econometrics (5th edition). McGraw Hill, 2007.

[24] Data for 2008–2011 as well as outlier scenarios (polmax0314a, polmaxlco20321a, polmaxlp0316a, lgbama050218a, lgbama200218a, aeo2010r1118a, oghtec110209a, ogltec110209a, hilng110209a, lolng110209a) were removed when running the model.

[25] This resulted in 1028 observations. Model R – Squared: 0.98. Note that this technique has many limitations when applied to this particular data, but was considered the best approach given study objectives and lack of better data. In addition to the current specification, the authors also explored a quadratic specification to account for a non-linear supply curve and various forms to model cumulative consumption before settling on this specification.

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Table A1
Technology cost ($2010) and performance assumptions used in ReEDS.

	Capital cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-year)	Heat rate (MMBtu/MWh)
Coal integrated gasification combined cycle CCS				
2010	4075	7	32	9.0
2020	4075	7	32	9.0
2030	4075	7	32	7.9
2040	4075	7	32	7.9
2050	4075	7	32	7.9
CSP				
2010	7179	NA	50	NA
2020	6639	NA	50	NA
2030	5398	NA	50	NA
2040	4778	NA	50	NA
2050	4778	NA	50	NA
Combined cycle plants				
2010	1250	4	6	7.5
2020	1250	4	6	6.7
2030	1250	4	6	6.7
2040	1250	4	6	6.7
2050	1250	4	6	6.7
Combined cycle plants CCS				
2010	3348	10	19	10.0
2020	3267	10	19	10.0
2030	3267	10	19	10.0
2040	3267	10	19	10.0
2050	3267	10	19	10.0
Simple-cycle combustion turbines				
2010	661	30	5	12.5
2020	661	30	5	10.3
2030	661	30	5	10.3
2040	661	30	5	10.3
2050	661	30	5	10.3
New coal				
2010	2937	4	23	10.4
2020	2937	4	23	9.4
2030	2937	4	23	9.0
2040	2937	4	23	9.0
2050	2937	4	23	9.0
Nuclear				
2010	6199	NA	129	9.7
2020	6199	NA	129	9.7
2030	6199	NA	129	9.7
2040	6199	NA	129	9.7
2050	6199	NA	129	9.7
Utility-scale PV[a]				
2010	4067	NA	51	NA
2020	2560	NA	46	NA
2030	2351	NA	45	NA
2040	2191	NA	38	NA
2050	2058	NA	33	NA
Wind offshore[b]				
2010	3702	0	101	NA
2020	3355	0	101	NA
2030	3042	0	101	NA
2040	3042	0	101	NA
2050	3042	0	101	NA
Wind onshore[c]				
2010	2012	0	60	NA
2020	2012	0	60	NA
2030	2012	0	60	NA
2040	2012	0	60	NA
2050	2012	0	60	NA

Note: A discussion of these cost and performance assumptions can be found in Black and Veatch (2012).
[a]Capacity factors for utility-scale PV are region specific and range from 17 to 28%.
[b]ReEDS models five separate offshore wind resource classes with capacity factors that range from 36 to 50%.
[c]ReEDS models five separate onshore wind resource classes with capacity factors that range from 32 to 46%.

Treating plant retirement in ReEDS

Assumptions about the retirement of conventional-generating units can have considerable cost implications. Considerations that go into the decision-making process on whether or not an individual plant should be retired involve a number of factors, specifically the economics of plant operations and maintenance. Projecting these economic considerations into the future given the uncertainties involved is beyond the scope of ReEDS, and instead ReEDS uses the following three retirement options that are not strictly economic:

- *Scheduled lifetimes for existing coal, gas, and oil*. These retirements are based on lifetime estimate data for power plants from Ventyx (2010). Near-term retirements are based on the officially reported retirement date as reported by EIA 860, EIA 411, or Ventyx unit research (Ventyx, 2010). If there is no officially reported retirement date, a lifetime-based retirement is estimated based on the unit's commercial online date and the following lifetimes:
- Coal units (<100 MW) = 65 years
- Coal units (>100 MW) = 75 years
- Natural gas combined cycle unit = 55 years
- Oil–gas–steam unit = 55 years
- *Usage-based retirements of coal*. In addition to scheduled retirements, coal technologies, including co-fired coal with biomass, can retire based on proxies for economic considerations. Any capacity that remains unused for energy generation or operating reserves for 4 consecutive years is assumed to retire. Coal capacity is also retired by requiring a minimum annual capacity factor; after every 2-year investment period, if a coal unit has a capacity factor of less than this minimum capacity factor during the 2-year period, an amount of coal capacity is retired such that the capacity factor increases to this minimum threshold (10% in 2030, 20% in 2040, and 30% in 2050). Coal plants are not retired under this algorithm until after 2020.
- *Scheduled nuclear license-based retirements*. Nuclear power plants are retired based on the age of the plant. Under default assumptions, older nuclear plants that are online before 1980 are assumed to retire after 60 years (one relicensing renewal), whereas newer plants (online during or after 1980) are assumed to retire after 80 years (two relicensing renewals). Other options can be implemented, such as assuming 60- or 80-year lifetimes for all nuclear plants.

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