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Exploring the role of natural gas power plants with carbon capture and storage as a bridge to a low-carbon future

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Abstract

Natural gas combined-cycle (NGCC) turbines with carbon capture and storage (CCS) could be an important source of low-carbon electricity in the future. Factors affecting the market competitiveness of NGCC-CCS are examined by conducting a sensitivity analysis using the MARKet ALlocation energy system optimization model. The results indicate that widespread deployment of NGCC-CCS is better suited for a 30% energy system greenhouse gas (GHG) reduction trajectory than for a more stringent 50% reduction trajectory. Methane leakage rate, efficiency penalty, carbon dioxide (CO_2) capture rate, and natural gas price are found to be the strongest factors influencing optimal NGCC-CCS deployment, in that order. NGCC plays an important role in meeting mid-term GHG targets across all model runs. A large portion of NGCC capacity is later retrofit with CCS, indicating that NGCC can be both a bridge to a low-carbon future and an integral part of that future. Thus, retrofitability and siting near CO_2storage should be considerations as new NGCC capacity is built. Regional results indicate that NGCC-CCS deployment would be greatest in the West South Central region, followed by the East North Central region. In a business-as-usual scenario, both regions have considerable electricity production from fossil fuels. Conventional coal and gas capacity are displaced under a GHG reduction target, opening the door for NGCC-CCS in these regions. NGCC-CCS market penetration is projected to have a mixed impact on air pollutant emissions and energy-related water consumption. Whether impacts are positive or negative depends on the technologies displaced by NGCC-CCS.

Keywords

Natural gas combined-cycle (NGCC); Carbon capture and storage (CCS) retrofits; Energy system modeling; Greenhouse gas mitigation

Introduction

Natural gas combined-cycle (NGCC) power plants have grown to be a major source of US electricity production. In 2010, electricity produced from natural gas was roughly half that of coal. By 2016, natural gas had become the largest source of electricity in the USA (EIA 2017). Many factors led to this outcome. For example, new NGCC plants have a lower investment cost, shorter construction time, and are easier to site than new nuclear and coal plants (Stark et al. 2015). Also, while natural gas market share historically has been limited by natural gas price and price volatility, advances in gas extraction methods have largely negated these issues (Lu et al. 2012).

Improvements in natural gas combustion efficiency have also driven market share. The average natural gas technology combustion efficiency in California in 2001 was 33%. By 2010, this average had grown to 40% (Nyberg 2014). In 2016, commercially available NGCC had reached an efficiency of 63% (MHPS 2016). NGCC now achieves a levelized cost of electricity that is nearly 24% less than that of new conventional coal plants (EIA 2016e). Furthermore, NGCC has considerably lower air pollutant emissions than coal boilers (GAO 2015; Rubin et al. 2012). Determining the net environmental impacts of NGCC can be complicated, however, since these impacts are location dependent and are also affected by the technologies and fuels that are being displaced by NGCC.

From a greenhouse gas (GHG) perspective, NGCC has some advantages relative to other fossil fuel technologies. For example, in 2015, the CO_2 intensity of electricity produced by NGCC was approximately one-third that of pulverized coal plants (EIA 2016a). Furthermore, carbon capture and storage (CCS) technologies can be applied to NGCC capacity (NGCC-CCS), reducing its CO_2 signature even further (Rubin et al. 2012). These factors have resulted in NGCC being discussed as a potential bridge to a low-CO_2 future that would increasingly rely on wind, solar, advanced nuclear, and CCS (C2ES 2013; Cole et al. 2016; Nichols and Victor 2015).

Conversely, a number of factors may negatively affect the long-term roles of NGCC and NGCC-CCS. For example, the fugitive methane emissions associated with natural gas production, transmission, and distribution would offset some of the GHG benefits relative to coal unless these emissions can be reduced (Lenox and Kaplan 2016; McJeon et al. 2014; EDF 2016). Even with CCS, some CO_2 inevitably escapes capture. These emissions put NGCC-CCS at a disadvantage for GHG mitigation compared to zero-carbon technologies such as wind and solar power (Cole et al. 2016). Furthermore, applying currently available CCS retrofit technologies would result in significant cost and efficiency penalties associated with capturing and compressing CO_2 gas for storage (Teir et al. 2010). Finally, the CO_2 concentration in the exhaust of NGCC is expected to be considerably lower than that of coal combustion. Low CO_2concentrations can reduce the cost-effectiveness of capture technologies (Rubin et al. 2012).

The quantity of water consumed by NGCC-CCS relative to that of other technologies is important when considering resilience to a changing climate. In 2010, thermoelectric energy production was responsible for 38% of fresh water withdrawals in the USA (GAO 2015). A portion of these withdrawals is returned to the source and therefore available for use again. However, a portion is consumed through evaporation and cannot be re-used on site. CCS retrofits to an NGCC plant with a recirculating cooling system would roughly double its water consumption to 1438 L/MWh. This rate is comparable to that of conventional coal power plants (Macknick et al. 2011), but is less than the 3202 L/MWh consumed by coal plants with CCS (Macknick et al. 2011; NETL 2007).

Assessments of CCS in the literature have yielded several relevant insights. These include: CCS is projected to be a cost-competitive GHG mitigation option post-2040 (Boot-Handford et al. 2014; Koelbl et al. 2015; Kriegler et al. 2014; Rubin et al. 2012; Williams et al. 2012); high market penetration of CCS requires a strong policy driver (McJeon et al. 2011; Rubin et al. 2012; Teir et al. 2010; Wright and Kanudia 2014; Yang et al. 2015); stringent carbon targets (e.g., 450 ppm CO_2 target by 2100 and 80% CO_2 reduction by 2050) will be difficult to reach in the long term in the absence of widespread deployment of CCS (Cole et al. 2016; Eide 2013; IPCC 2014; McJeon et al. 2011; Nichols and Victor 2015; Yang et al. 2015); and low natural gas prices and CCS capital cost reductions would be necessary for widespread NGCC-CCS deployment (Cole et al. 2016; Logan et al. 2013; Nichols and Victor 2015; Wright and Kanudia 2014).

One of the more similar applications to ours is that of Nichols and Victor (2015), who examined the system-wide effects of shale gas development and carbon taxes on the US energy system using MARKAL. While the authors explored various assumptions related to natural gas supply and cost, social cost of carbon, and CCS cost, they did not explicitly examine the topic of retrofits. They also did not explore changes in air pollutant emissions or water use. Rubin et al. (2012) also examined CCS deployment for 50 and 80% GHG reduction targets in 2050. However, both studies were at the national level and did not draw insights specific to regional deployment of CCS technologies in the USA.

In this work, we build upon the literature by exploring retrofits and environmental endpoints. We seek to answer questions such as: (1) “How is the competitiveness of NGCC-CCS affected by technology, fuel, and emission assumptions?”, (2) “Is NGCC-CCS more competitive in some parts of the country than others?”, (3) “What are the net implications of widespread NGCC-CCS penetration on environmental metrics such as air pollutant emissions and water usage?”, and (4) Can NGCC be both a bridge to a low-CO_2 future and, via the retrofit of CCS equipment, a major component of that future if and when the necessary regulatory or economic drivers for GHG reductions are in place?”

Approach

The MARKet ALlocation (MARKAL) energy system optimization model (Loulou et al. 2004) is used to examine the regional deployment of NGCC-CCS through 2055 over a wide range of assumptions. The MARKAL model, as well as relevant data and assumptions, is discussed in “Model and database description” section. The experimental design is described in “Experimental design” section.

Model and database description

MARKAL is a bottom-up, energy system optimization model. The model uses linear programming techniques to identify the technologies and fuels that satisfy end-use energy demands over the modeled time horizon at lowest cost, while simultaneously meeting constraints such as resource and emissions limits. Inputs to MARKAL include supply curves for energy resources; characterizations of the current and future technologies, including their costs, efficiencies, and emission and water use factors; estimates of current and future energy demands; and constraints that represent regulatory limits on outputs such as air pollutant and GHG emissions. Using this information, MARKAL produces estimates of total system costs, fuel use, market penetrations of energy technologies, domestic production of energy resources, inter-regional trade of energy commodities, electricity generation and capacity expansion costs, marginal energy prices, criteria and GHG emissions, and energy-related water demands. Readers searching for a detailed description of the model formulation are referred to Loulou et al. (2004).

The MARKAL model has been used by dozens of organizations around the world (ETSAP 2017). To apply the model to a particular energy system, a database must be developed that describes the MARKAL inputs for that system. We use the EPAUS9r-14-v1.5 MARKAL database, which allows the US energy system to be modeled for the period spanning 2005–2055, in 5-year increments, at the US census division resolution (Fig. 1). Economic sectors represented in the database include electric sector, energy supply and energy-intensive industries, the commercial and residential sectors, and the transportation sector. The database was developed by the Environmental Protection Agency (EPA)'s Office of Research and Development to aid in projecting GHG and air pollutant emissions for various scenarios of the future. The resulting MARKAL framework allows exploration of alternative assumptions regarding population and economic growth, technology development, and energy and environmental policies (Lenox et al. 2013). EPA has applied MARKAL for a wide range of applications, including emission projections (Ran et al. 2015), technology assessment (Aitken et al. 2016), and emission control strategy evaluation (Loughlin et al. 2017).

An important aspect of the EPA database is its inclusion of air pollutant emissions and controls, as well as representations of environmental and energy regulations. For example, the electric sector contains control requirements that approximate the Mercury and Air Toxics Standards (MATS) rule (Federal Register 2012a), regional NO_x and SO_2 constraints that represent the Cross-State Air Pollution Rule (CSAPR) (Federal Register 2011), and regional CO_2 constraints that reflect the Clean Power Plan (CPP). Regional constraints are based upon the EPA's Integrated Planning Model (IPM) analysis of the CPP (Federal Register 2015). State-level renewable portfolio standards (RPS) are aggregated and represented in MARKAL at the regional level (DSIRE 2010). These standards require a percentage of electricity to come from renewable sources. The Corporate Average Fuel Economy (CAFE) standards for light duty vehicles are included in the transportation sector (FederalRegister 2012b). The primary source of data for the EPAUS9r database is the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) (EIA 2014a).

We assume that CCS for natural gas plants becomes available in 2025. NGCC and coal plants can be built with CCS or can be retrofit with CCS in a later time period. The cost and performance characteristics of CCS technologies are drawn from AEO2014 (EIA 2014a). CCS-related water consumption is only considered for the cooling system and is estimated to be 1783 and 681 L/MWh for coal and natural gas with CCS retrofits, respectively (Macknick et al. 2011). Water consumption associated with coal and natural gas extraction and production is not currently considered. The CO_2 capture rate is assumed to be 90 and 85% for CCS paired with coal and NGCC, respectively, reflecting the additional difficulty in removing CO_2 from the lower-concentration NGCC exhaust stream. These capture rates are

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based upon discussions with other energy system modelers and could be revisited if and when new CCS technologies data become available.

The cumulative regional CO_2 storage capacity varies across regions and increases over time (NETL 2010). While there are no geological capabilities to store captured CO_2 in Region 1, captured CO_2 could be transported to storage sites in other regions (Chaudhry et al. 2013). Since electricity production in Region 1 is small compared to other regions, and since all other regions have large storage capacities, we neglect inter-regional transport. The CO_2 storage cost is assumed to be 9.7 $/tonne of CO_2 for all regions (IPCC 2005). While we are testing an alternative formulation that represents CCS costs via region-specific supply curves, that work was not completed in time for inclusion here.

Experimental design

The experimental design consists of three components. First, electricity production under a business-as-usual (BAU) scenario is examined and compared to that of three scenarios involving increasingly stringent GHG reduction trajectories. Next, a parametric sensitivity analysis is conducted to evaluate how NGCC-CCS market penetration in the 50% GHG mitigation scenario responds to assumptions about various technological and contextual parameters. Finally, a nested parametric sensitivity analysis is used to explore the interplay among GHG reduction target, methane leakage rate, and the corresponding optimal NGCC-CCS market penetration. Optimality implies the capacity and utilization that minimizes the net present value of the energy system, subject to the GHG reduction target and other modeled constraints. The three parts of the experimental design are described in more detail below.

GHG mitigation scenario analysis—A BAU scenario is based upon the base case included in the version 2014-v1.5 of the MARKAL 9-region database, but with several modifications. First, the investment cost of solar photovoltaics (PV) is updated based on the IPM model v.5.15 inputs (EPA 2015) to reflect recent PV technological advancements. Second, hurdle rates, which are used to simulate corporate and consumer preferences, are modified to be 5% for coal and nuclear lifetime extensions, 15% for new nuclear plant builds, and 10% for other new power plants. The hurdle rates replace the 5% global discount rate used by the model when amortizing capital cost over the power plant lifetime. The lower rate for lifetime extensions simulates a corporate and societal desire to avoid stranding assets. The higher rate for nuclear power represents siting difficulties, corporate risk associated with large capital-intensive investments, and a hesitancy to invest in nuclear power based upon perceived safety concerns. An upper bound on new nuclear capacity is assumed to be 5 GW in 2020 based on the AEO 2014 high nuclear case (EIA 2014b). The cumulative new nuclear capacity is constrained to grow no more than 5% annually from 2020 to 2055 (World-nuclear 2016).

In addition to the BAU, three GHG mitigation scenarios are developed. The scenarios, referred to as GHG30, GHG40, and GHG50, involve the application of 30, 40, and 50% energy system-wide GHG reduction trajectories to the BAU. These nation-wide constraints require 2050 energy system GHG emissions to be reduced by the specified percentage relative to the 2005 level, following a linear trajectory with reductions starting in 2025. The constraints are applied to the sum of emissions across the electric, energy supply, commercial, residential, industrial, and transportation sectors. The GHG emissions are based on the 100-year global warming potential (GWP) for CO_2, sulfur dioxide (SO_2), nitrogen oxides (NO_x), methane, black carbon, carbon monoxide, nitrous oxide, organic carbon, and volatile organic compounds. Total energy system GHG emissions from the BAU, along with the three GHG constraints, are depicted in Fig. 2.

The BAU and three GHG-constrained scenarios are evaluated with MARKAL. For each scenario, optimal national and regional NGCC-CCS deployments are recorded, as are electricity production by technology, energy system-wide NO_x, SO_2, and CO_2 emissions, and energy-related water demands.

Parametric sensitivity analysis—A list of 20 parameters within MARKAL deemed a priori to likely have the greatest effect on NGCC-CCS market penetration are presented in Table 1, along with estimates of alternative values for each. National and regional NGCC-CCS deployments are examined under GHG50 for the baseline and alternative values of each factor, modified one at a time and with all other parameters being at their baseline values.

Table S7 in the Online Resource lists the 44 sensitivity runs that were conducted in this part of the analysis, as well as the underlying assumptions. The parameters are categorized into two groupings: (1) technology parameters are associated with cost and performance characteristics of NGCC-CCS, and (2) contextual parameters describe the conditions in which the technology competes, including the characteristics of competing technologies, future fuel prices, and energy and emission policies.

Nested parametric sensitivity analysis—The results of the parametric sensitivity analysis, discussed in the next section, indicate that the methane leakage rate assumption has a critical role in determining optimal NGCC-CCS deployment under GHG50. To explore this result further, a nested sensitivity analysis is conducted to evaluate the interplay among leakage rates, GHG reduction targets, and NGCC-CCS deployment in 2050. A nested parametric sensitivity analysis differs from a parametric sensitivity analysis by including perturbations to multiple parameters simultaneously. Specifically, we evaluated all combinations of leakage rates of 0.25, 1, 2.3, 4, and 7% and GHG reduction targets of 30, 40, and 50%. The selected methane leakage rates are derived from the literature (Caulton et al. 2014; Lenox and Kaplan 2016; Peischl et al. 2015) and reflect the wide range of emission estimates.

Results and discussion

In this section, results are presented for the three parts of the experimental design: GHG mitigation scenarios analysis, parametric sensitivity analysis, and nested parametric sensitivity analysis.

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GHG mitigation scenario analysis

Figure 3 presents national-scale electricity production for the BAU and three system-wide GHG cap scenarios.

In the BAU scenario, coal use declines initially and then levels off from 2030. Natural gas, wind, and solar power increase market share, meeting most of the growing electricity demands. CCS does not penetrate the market aside from a small portion applied to new coal plants. The appearance of CCS is driven by the representation of the NSPS for new coal plants that limits the CO_2 emissions rate from these plants to 499 gr/KWh.

Under GHG30, renewables expansion and CCS retrofits to existing coal plants are the primary GHG reduction measures applied through 2045. In 2050, however, more than 70% of NGCC capacity is fit with CCS, with this percentage increasing to almost 100% in 2055.

For GHG40 and GHG50, NGCC-CCS continues to play a role in mitigation, but market share is lost to coal-integrated gasification combined cycle (IGCC) with CCS, likely due to both the higher CO_2 capture rate and the lower upstream methane leakage rate for coal relative to gas. Nonetheless, under GHG40, NGCC-CCS produces approximately 500 TWh of electricity in 2050. For context, this quantity is equivalent to 12% of total US electricity generation in 2016 (EIA 2017) and 9.2% of the projected generation in 2050.

Parametric sensitivity analysis

The 44 sensitivity runs that evaluated perturbations under GHG50 produce a wide range of NGCC-CCS deployment. Figure 4 compares the electricity production in 2050 by NGCC-CCS across the various sensitivity runs. The 50% energy system CO_2 reduction trajectory ($CO_2$50) is also included in the sensitivity runs to represent the impact of not considering upstream coal and natural gas emissions on NGCC-CCS market penetration. Parameters related to cost and performance characteristics of NGCC-CCS are presented with blue columns. Contextual parameters with a range of values are presented with red columns. Contextual parameters without a range of values are presented with a red boundary, which corresponds to the baseline deployment when the parameter is not employed (off). The low or high end of the red boundary represents 2050 electricity generation from NGCC-CCS when the contextual parameter is applied (on).

The results illustrate that NGCC-CCS market penetration is very sensitive to NGCC-CCS cost and performance assumptions, as well as to broader contextual assumptions. For example, using a very low methane leakage rate assumption approximately triples NGCC-CCS deployment in 2050. In contrast, the very high leakage rate assumption results in no NGCC-CCS deployment.

Among the parameters associated with NGCC-CCS cost and performance (solid blue bars), variations in generating efficiency, which is directly affected by the CCS efficiency penalty, and CO_2 capture rate have a greater impact than those of investment cost, CCS cost, and CO_2storage cost. This result indicates that, across the ranges examined, reducing the CCS efficiency penalty is more important than capital cost reductions in driving NGCC-CCS deployment.

NGCC-CCS efficiency has such a large impact that it likely affects competition by several mechanisms. For example, a higher efficiency decreases fuel expenditures to achieve the same quantity of electricity production. It also decreases the captured emissions that must be compressed, transported, and stored. Furthermore, increased efficiency decreases uncaptured CO_2 and upstream emissions from methane leakage, both of which count against the GHG constraint. Since NGCC-CCS has yet to be applied at a commercial scale, the ultimate efficiency is an unknown.

Similarly, the CO_2 capture rate for NGCC-CCS is highly uncertain, as is how this rate will compare to that of coal technologies with CCS. Another uncertainty is how these capture rates may improve as capture technologies are commercialized.

Among the contextual parameters (solid and outlined red bars), maximum electrification of light duty vehicles (LDVs) and a very low natural gas price are the next strongest drivers of NGCC-CCS deployment after the methane leakage rate. LDV electrification increases electricity demands, requiring expansion of generating capacity, while also allowing some additional electric sector GHG emissions under the system-wide cap by reducing transportation emissions. In contrast, the forced retirement of existing nuclear via not allowing lifetime extensions results in a decrease in NGCC-CCS of 195 TWh to compensate for having less carbon-free nuclear capacity available.

Most other contextual parameters have virtually no effect on NGCC-CCS output. One exception is whether the mitigation target is defined as a GHG target or as a CO_2 target. When we instead seek a 50% CO_2 reduction, and thus ignore upstream coal and gas emissions, the US electricity generation from NGCC-CCS increases by 230 TWh in 2050. This result indicates the importance of how the reduction constraint is defined and what is included.

Across the full set of parametric sensitivity runs, the following important observations are made. With the exception of sensitivity runs that involved high natural gas prices, NGCC played a significant short- to mid-term role in producing electricity. As GHG trajectories became more stringent in the long term, a large fraction of this NGCC was retrofit with CCS as well as replaced with coal IGCC-CCS and renewables.

Next, regional deployment of NGCC-CCS is examined. A series of boxplots are presented in Fig. 5 to indicate the range of deployment in 2050 for each region across BAU and 44 sensitivity runs. For each boxplot, the circle represents electricity production for GHG50, which overlaps the median in all regions except Region 3. The edges of the box present the 25th and 75th percentiles, and the whiskers extend to minimum and maximum NGCC-CCS deployment in each region. The numbers in the table represent the 2050 electricity production share from NGCC-CCS in each region.

The highest average deployment of NGCC-CCS occurs in Region 7, which has considerable natural gas, coal, and renewable resources. For example, in 2015, Region 7 accounted for

45% of US natural gas production (EIA 2016b). Furthermore, Texas, which is in Region 7, is ranked 5th among states in coal production and 1st in electricity from wind (EIA 2016c, d). Faced with one of the GHG constraints in MARKAL, Region 7 responds by either retrofitting existing coal with CCS or retiring that capacity and replacing it with NGCC-CCS or renewables. Across the sensitivity runs, the various parametric perturbations shift the balance among these options, resulting in a wide range of deployment outcomes.

Like Region 7, Regions 3 and 5 also have high average levels of NGCC-CCS market penetration, as well as relatively large ranges of deployment. These regions have similar drivers to Region 7 (e.g., high reliance on fossil energy, while also having access to renewable resources), albeit to lesser extents. Regions 2, 4, 6, 8 and 9 experience comparatively smaller NGCC-CCS deployment. Regions 4, 8, and 9 have access to high-quality wind or solar resources, limiting the competitiveness of NGCC-CCS. As mentioned previously, Region 1 is assumed to have negligible carbon storage resources. See the Online Resource for additional information about regional deployment.

Next, in Fig. 6, electricity generation mixes for the sensitivity runs resulting in the lowest and highest NGCC-CCS deployments are shown.

The lowest NGCC-CCS deployment under GHG50 corresponds to very high natural gas price. In this scenario, existing coal is retrofitted with CCS starting in 2020. Coal IGCC-CCS largely displaces NGCC, likely due to their relative fuel costs and the higher CO_2 capture rate of coal IGCC-CCS.

The highest NGCC-CCS deployment under GHG50 corresponds to a very low methane leakage rate. While the 1100 TWh of electricity produced via NGCC-CCS in that scenario is substantial, it is less than 20% of total generation in that year. This result indicates that NGCC-CCS could need to be part of a broader portfolio, even under optimistic assumptions.

Nested sensitivity analysis

Results shown in Fig. 7 allow additional exploration of the role of methane leakage rate and its interplay with the GHG mitigation target. The figure presents electricity generation, energy consumption, system-wide air pollutant emissions, and water usage for the combinations of various GHG mitigation targets and methane leakage rates in 2050. The correlation coefficients between NGCC-CCS deployment and each parameter are shown in the upper right corner of each table.

The baseline methane leakage assumption is 2.3%. At this rate, NGCC-CCS deployment decreases as the GHG reduction target becomes more stringent. For GHG30, NGCC-CCS deployment is not sensitive to leakage rate until the rate exceeds 4%. For GHG50, NGCC-CCS deployment is very sensitive to leakage, and deployment falls to zero between leakage rates of 4 and 7%.

Figure 7 also allows us to examine how other technologies respond to these assumptions and, via correlation coefficients, how their deployment is related to that of NGCC-CCS. These coefficients indicate that the quantity of electricity from nuclear power is not correlated with that of NGCC-CCS. The upper bound on nuclear capacity is binding in all 15 sensitivity cases, so nuclear deployment remains fixed at 986 TWh in 2050. A conclusion is that the model prefers nuclear power to other options for mitigating GHGs, at least up to the constraint. This result is highly dependent on assumptions such as the nuclear hurdle rate. Also, this result assumes that the cost of nuclear power is amortized over the 40-year lifetime of the nuclear plant. Real-world financing may be very different than this, e.g., with capital costs being repaid over a shorter period, which may result in corporate decision making that is very different than the modeled optimal nuclear capacity.

NGCC-CCS has a relatively strong correlation with conventional coal with CCS, 0.63, and strong inverse correlations with IGCC-CCS, − 0.92, and wind and solar power, − 0.67. The competition with coal technologies (with CCS) and with renewables appears to be affected by both the methane leakage rate and the stringency of the GHG target. At the baseline leakage rate and GHG30, NGCC-CCS competes favorably with IGCC-CCS. Competition tilts in the favor of IGCC-CCS as the GHG reduction target becomes more stringent or the leakage rate higher. The response of wind and solar to these perturbations appears to be more complicated. In general, their deployment is more affected by the stringency of the GHG reduction target than with the methane leakage rate assumption.

NGCC-CCS deployment and the total quantity of electricity produced have a negative correlation in these runs, − 0.64. Total electricity production increases as the GHG cap becomes more stringent, reflecting electrification of enduses (e.g., transportation, industry, buildings). Electricity demands also tend to increase with higher leakage rates as the model attempts to electrify end-uses further, avoiding both direct GHG emissions and methane leakage associated with the natural gas that is ultimately used in industry and buildings. Adding to the complexity are the different efficiencies of natural gas used for electricity production and in industry and buildings. For example, NGCC units typically have efficiencies over 45%, while natural gas combusted for heat could have efficiencies well over 90%. As MARKAL chooses the optimal utilization of fuels and technologies, it accounts for these differences.

NGCC-CCS deployment is positively correlated with NO_x and SO_2 emissions, 0.51 and 0.74, respectively, likely a result of its competition with wind and solar power. The system-wide SO_2 and NO_x emissions decrease with more stringent GHG caps and increasing methane leakage rates. The GHG cap is correlated to reduced emissions since many low- and zero-carbon electricity sources are also low in pollutant emissions. Similarly, increasing the methane leakage rate forces the adoption of more low-CO_2 measures in the electric sector to compensate, also reducing air pollutant emissions.

While having a fairly strong negative correlation, − 0.72, energy-related water demands are shown to have a complex relationship to NGCC-CCS deployment. National water consumption falls with higher methane leakage rates in GHG30 since NGCC-CCS is losing market share to renewables such as wind and solar power, which require comparatively little water. In contrast, under GHG50, NGCC-CCS quickly loses market share to coal IGCC-CCS for the 4 and 7% leakage rates, leading to increases in water consumption since IGCC-CCS requires 2044 L/MWh and NGCC-CCS requires 1431 L/MWh.

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Conclusions

This application demonstrates the utility of a model-based technology assessment approach to explore regional conditions and wide-ranging technology performance and contextual assumptions. NGCC-CCS was found to have the potential to play a significant role in scenarios of reduced energy system-wide GHG emissions. Furthermore, NGCC has the potential to be both a bridge to a low-carbon energy future and, via retrofit with CCS, a part of that future.

The extent of this role, however, was found to be highly dependent on underlying assumptions. Across all of the assumptions evaluated, NGCC-CCS deployment in 2050 ranged from 0 to 20% of US electricity production. At the regional level, maximum market penetration in 2050 was 36%, which occurred in Region 7 in the low methane leakage rate assumption. Thus, NGCC-CCS may be more appropriately thought of as a component of mitigation, along with renewables and nuclear power, as opposed to a silver bullet.

Of the parameters evaluated, NGCC-CCS deployment was most sensitive to the methane leakage rate. High leakage rates tipped the balance toward IGCC-CCS or renewables. NGCC-CCS was also found to be very sensitive to NGCC efficiency and the CCS efficiency penalty (evaluated together as NGCC-CCS efficiency), the CO_2 capture rate, and natural gas price, in that order.

The modeling results suggest that NGCC-CCS has the potential to be utilized across the USA. From the results, we can hypothesize that primary drivers for high regional deployment include high levels of fossil-based generation in the BAU scenario and access to natural gas resources.

NGCC-CCS market penetration is shown to have a mixed impact on air pollutant emissions and energy-related water consumption, depending on the region and which technologies it displaces. Both water consumption and air pollution emission benefits relative to the BAU are greatest in regions with high BAU levels of coal generation. Relative to the other GHG mitigation options, NGCC-CCS tends to also provide emissions and water consumption benefits when displacing coal, but disbenefits when displacing solar and wind.

An important underlying factor is the model formulation used in this study, which uses perfect foresight of future conditions when optimizing. Thus, this NGCC expansion and later retrofit was deemed a cost-effective strategy for addressing increasingly stringent GHG reduction targets. This result also implies that application of NGCC in the short term may be a robust long-term strategy, although reductions in methane leakage and improvements in NGCC-CCS efficiency and capture rate would undoubtedly strengthen this potential. Additional considerations include design for retrofitability and siting at or near sequestration sites.

Several caveats should be noted regarding the modeling assumptions and results. The results of this work should not be interpreted as explicit predictions, but rather possible future pathways based on specific modeling assumptions. Furthermore, although the EPA database represents the regional differences in energy mix, emissions, and regulations, it does not have resolution to examine state-level energy and emission policy options or access to energy resources. For example, there is a significant difference in the electricity generation mix between the states of Arizona and Montana in Region 8 that would neither be captured in the model inputs nor outputs. Future work could focus on finer spatial representation of the US energy system, provided that an appropriate state-level model becomes available.

The work in this paper could be extended in several ways. Region-specific CO_2 storage supply curves could be incorporated to improve the characterization of CCS costs. Also, the regional market penetration of NGCC-CCS and its effects on the energy system could be examined in response to other sensitivity parameters: (1) changing methane leakage rates and CO_2 capture rates over time, (2) including CO_2 leakage from CO_2 storage sites, (3) including emissions associated with CO_2 transport through pipelines and trucks, (4) representing transport of $CO_2$from one region to another, (5) revisiting the hurdle rate assumptions for various technologies, (6) incorporating enhanced oil recovery (EOR) revenues into the CO_2 storage costs, and (7) exploring the implications of operational constraints when NGCC is retrofit by CCS, such as more limited ability to vary output quickly to respond to demand changes. Finally, it would be worthwhile to perform additional nested sensitivity analyses to explore simultaneous changes to parameters such as natural gas prices, NGCC-CCS efficiency, and CO_2 capture rate.

Supplementary Material

Refer to Web version on PubMed Central for supplementary material.

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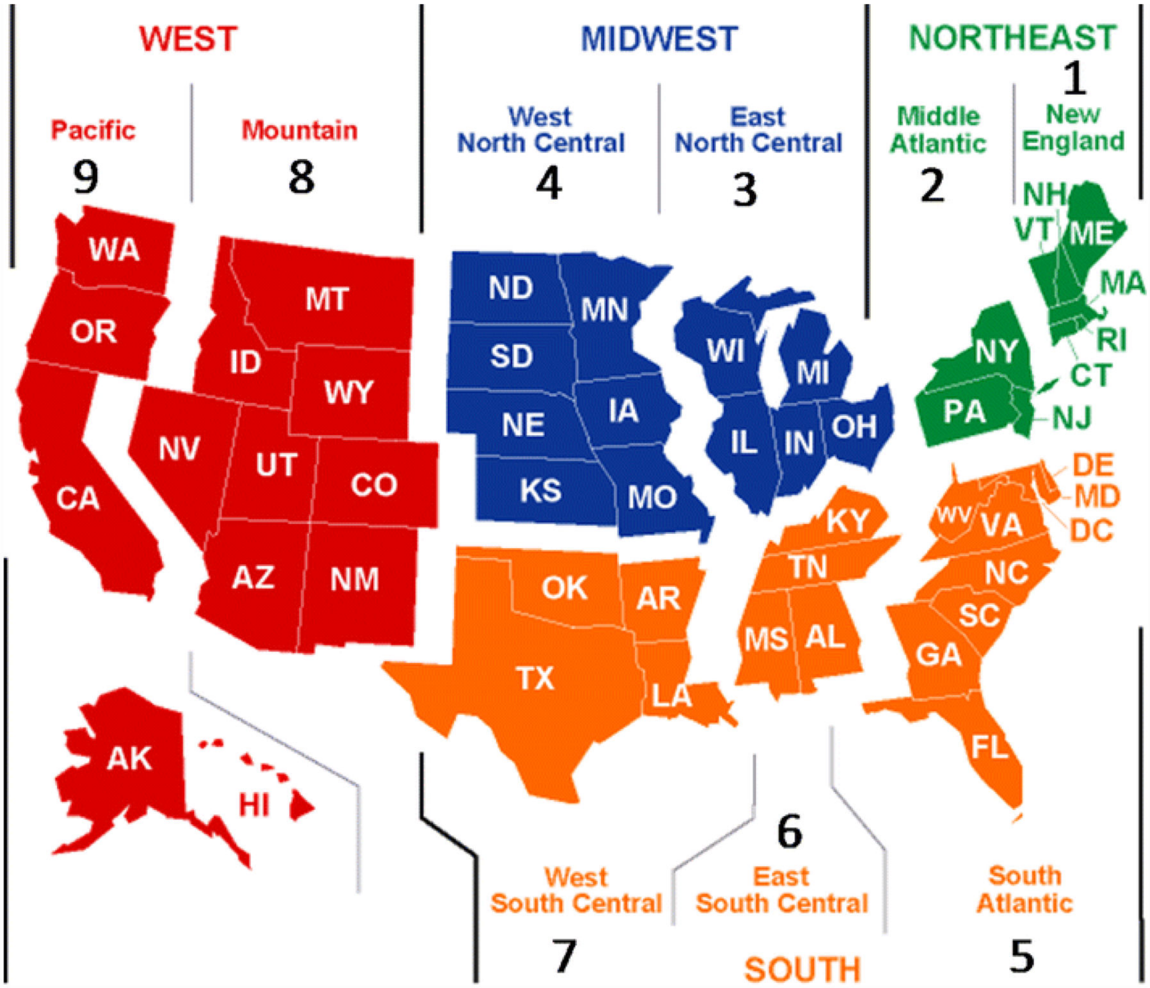

Fig. 1.

The representation of EPAUS9r regions based on the nine US census divisions (EIA 2012)

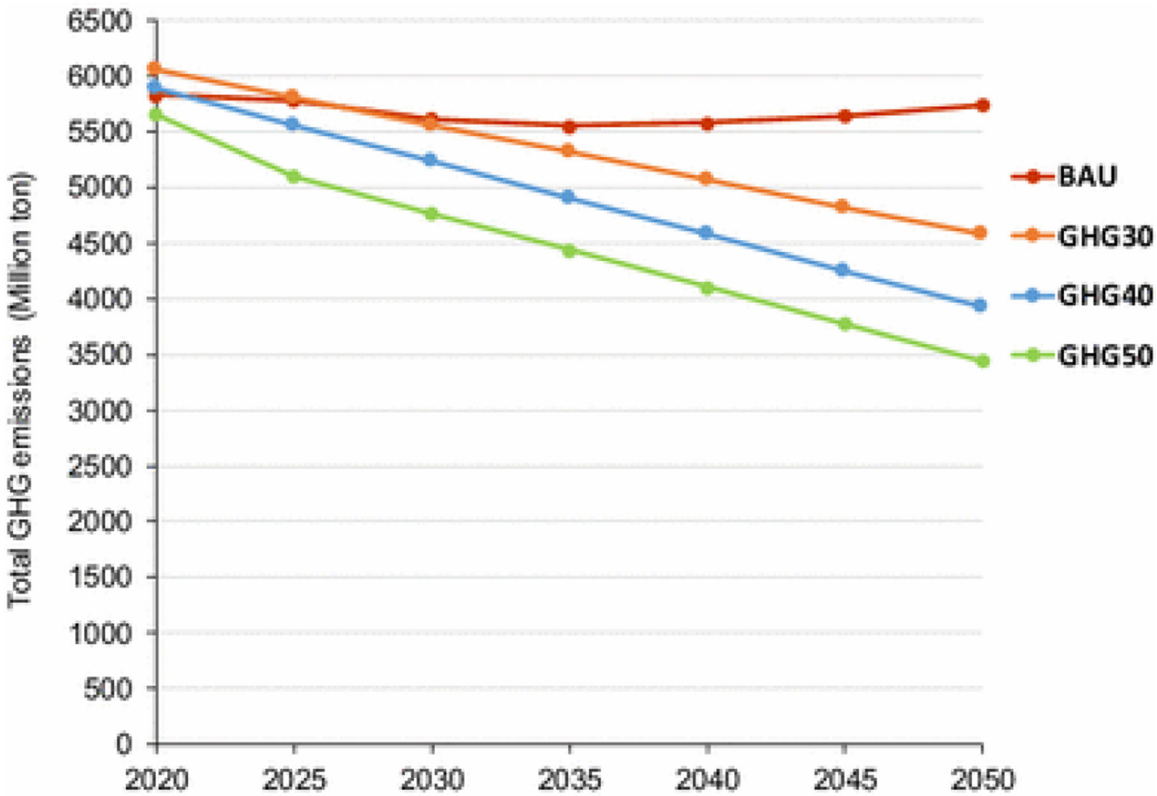

Fig. 2.

Total system-wide GHG emissions for business as usual (BAU), 30, 40, and 50% GHG reductions in 2050 relative to the 2005 level

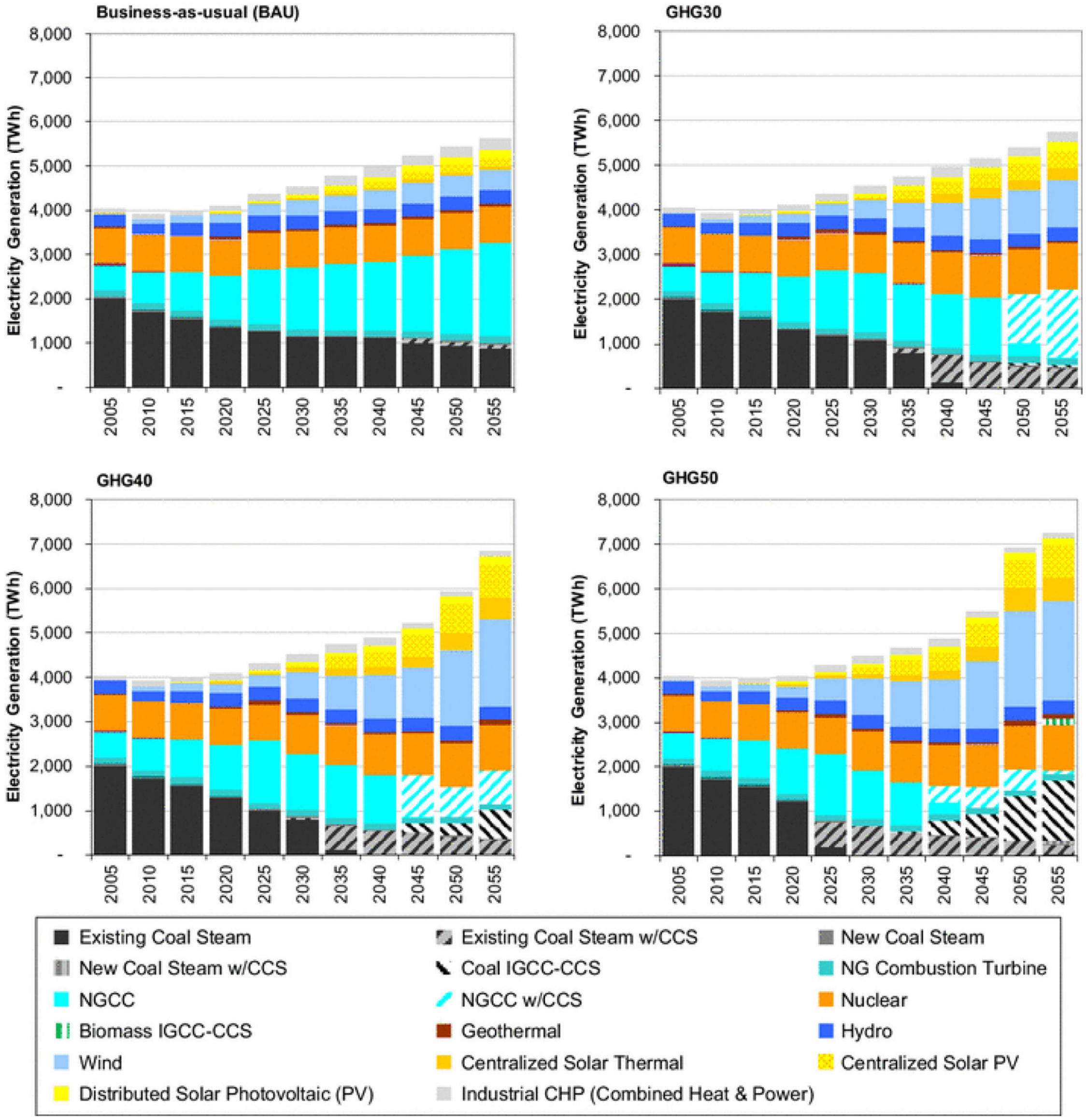

Fig. 3.
Electricity generation by aggregated technology for the business-as-usual (BAU), GHG30, GHG40, and GHG50 scenarios

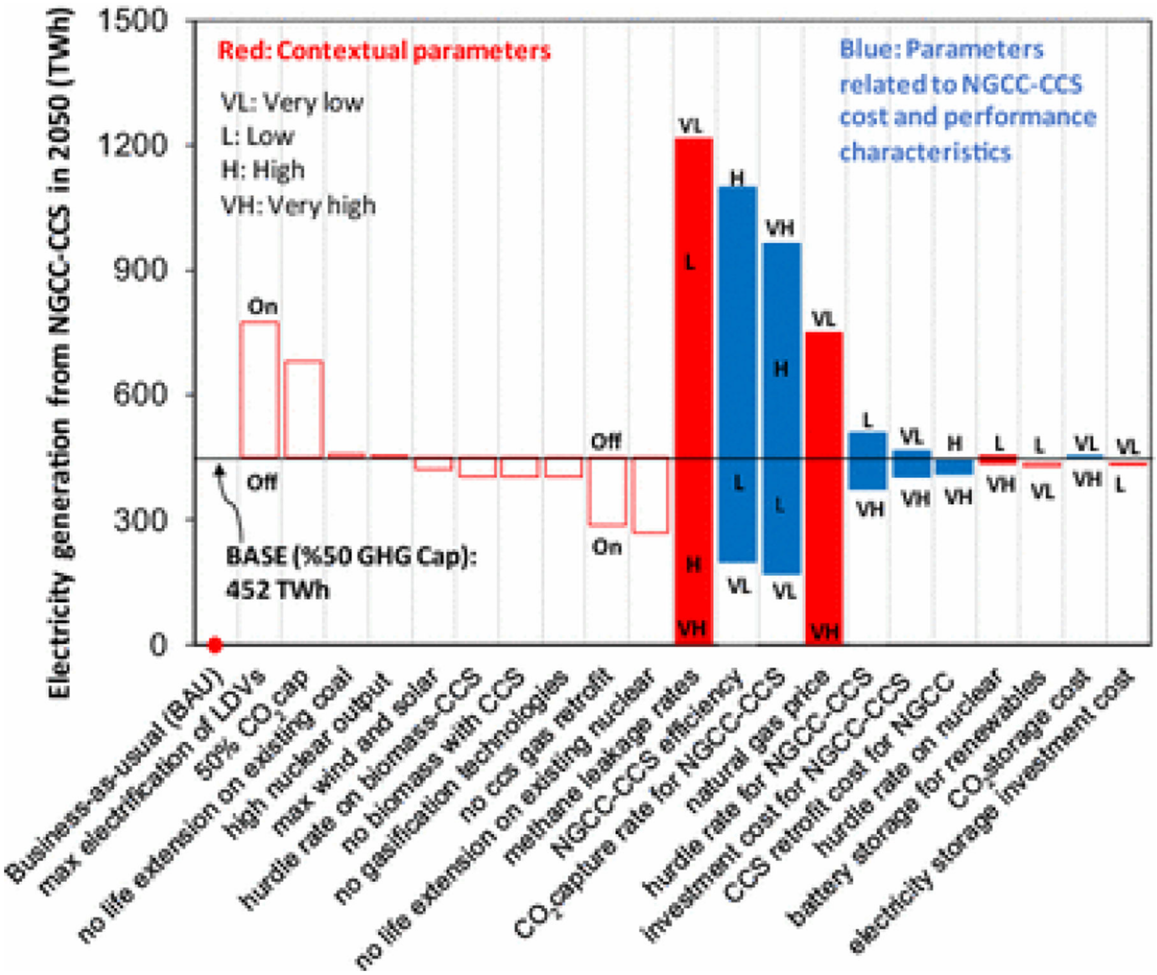

Fig. 4.

The estimated range of electricity production from NGCC-CCS in 2050 across BAU, $CO_2$50, and 44 sensitivity runs under GHG50

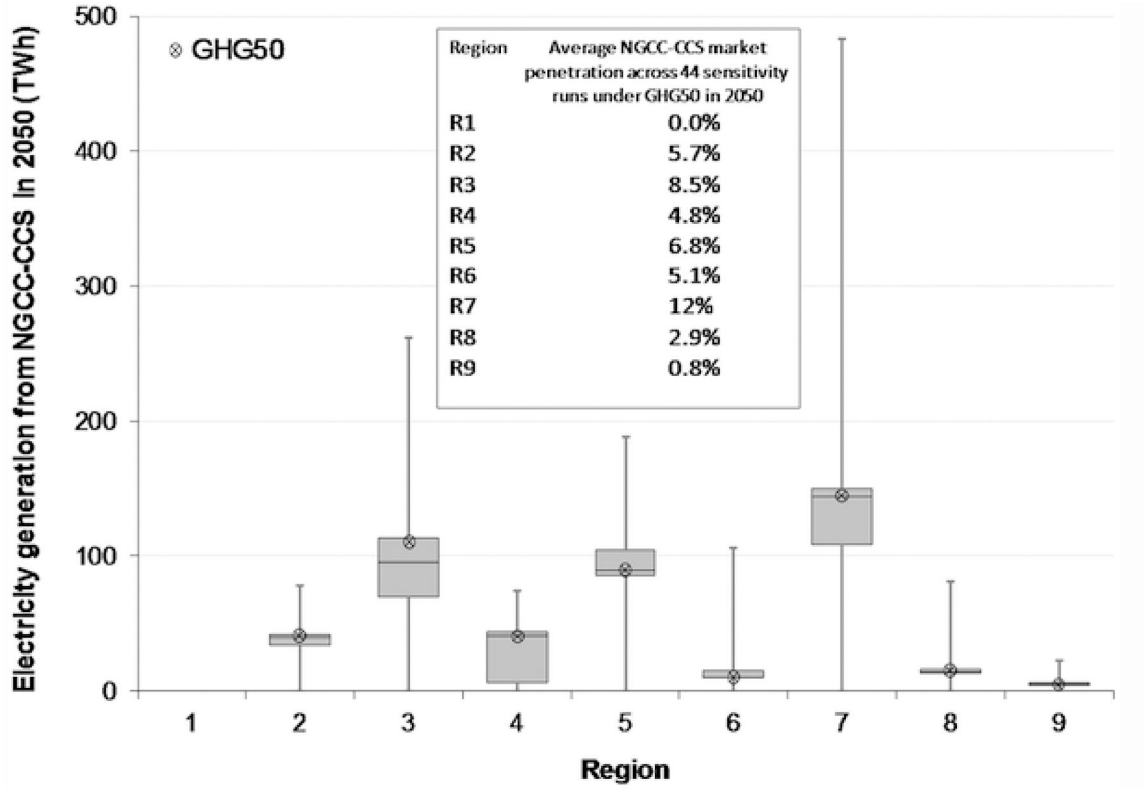

Fig. 5.

The projected range of NGCC-CCS adoption across BAU and 44 sensitivity runs in each region in 2050

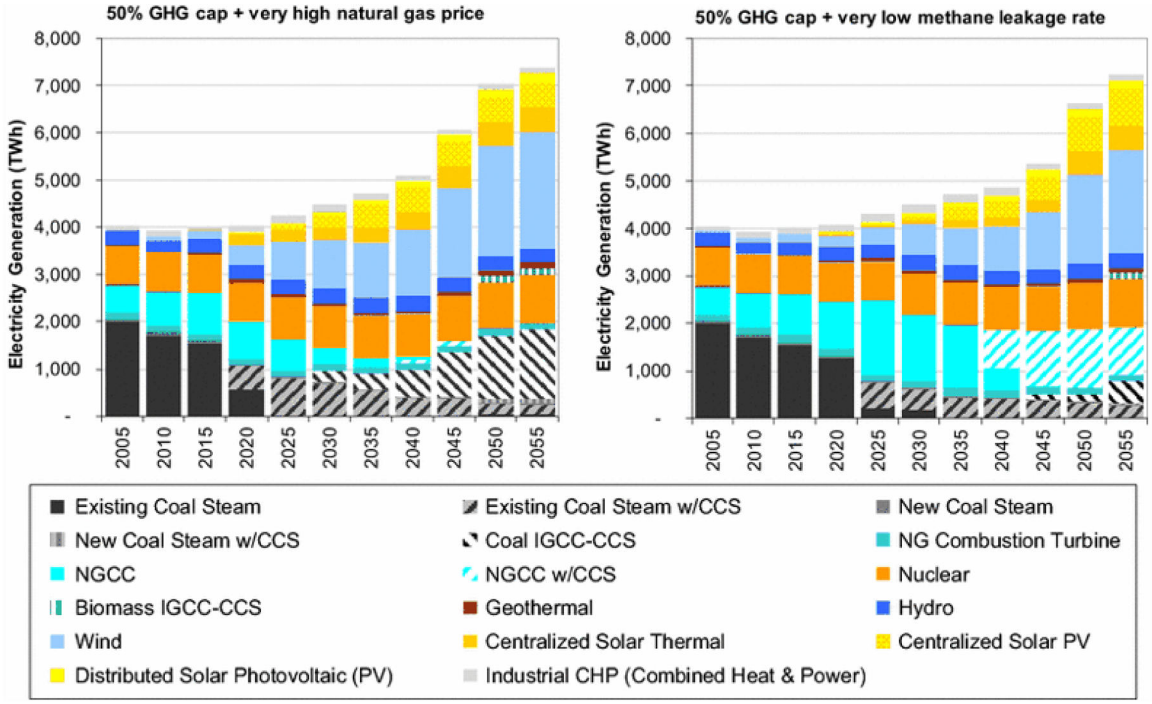

Fig. 6.

Electricity generation by plant type over time for the lowest NGCC-CCS deployment scenario (left) and the highest NGCC-CCS deployment scenario (right)

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NGCC-CCS deployment (TWh)					
GHG cap	Methane leakage rate				
	0.25%	1.00%	2.30%	4.00%	7.00%
GHG30	1060	1030	1100	1100	544
GHG40	1170	922	678	492	236
GHG50	1220	869	453	106	0.00

Coal without CCS deployment (TWh)					-0.28
GHG cap	Methane leakage rate				
	0.25%	1.00%	2.30%	4.00%	7.00%
GHG30	29.2	29.2	28.9	28.3	27.4
GHG40	25.9	25.9	25.9	25.9	26.0
GHG50	34.2	36.3	28.9	29.1	46.2

Coal IGCC-CCS deployment (TWh)					-0.92
GHG cap	Methane leakage rate				
	0.25%	1.00%	2.30%	4.00%	7.00%
GHG30	0.00	0.00	52.8	147	267
GHG40	0.00	52.8	275	561	1020
GHG50	139	539	986	1240	1330

Nuclear deployment (TWh)					0.00
GHG cap	Methane leakage rate				
	0.25%	1.00%	2.30%	4.00%	7.00%
GHG30	986	986	986	986	986
GHG40	986	986	986	986	986
GHG50	986	986	986	986	986

Wind and solar deployment (TWh)					-0.67
GHG cap	Methane leakage rate				
	0.25%	1.00%	2.30%	4.00%	7.00%
GHG30	1410	1510	1710	1900	2420
GHG40	2320	2590	2930	3030	3260
GHG50	3260	3350	3470	3470	3490

Coal with CCS retrofit deployment (TWh)					0.63
GHG cap	Methane leakage rate				
	0.25%	1.00%	2.30%	4.00%	7.00%
GHG30	544	542	498	474	456
GHG40	421	416	412	395	372
GHG50	337	346	336	298	291

Total natural gas consumption (TWh)					0.88
GHG cap	Methane leakage rate				
	0.25%	1.00%	2.30%	4.00%	7.00%
GHG30	8210	8020	7650	7110	5920
GHG40	7170	6570	5720	5160	4240
GHG50	6190	5340	4690	4270	3860

Water consumption (trillion liters)					-0.72
GHG cap	Methane leakage rate				
	0.25%	1.00%	2.30%	4.00%	7.00%
GHG30	5630	5600	5590	5550	5140
GHG40	5330	5120	5690	6130	7120
GHG50	6330	6910	7320	7550	7670

Total electricity production (TWh)					-0.64
GHG cap	Methane leakage rate				
	0.25%	1.00%	2.30%	4.00%	7.00%
GHG30	5420	5420	5410	5390	5420
GHG40	5570	5630	5940	6130	6560
GHG50	6620	6790	6920	6910	6950

Total CO_2 (million ton)					0.69
GHG cap	Methane leakage rate				
	0.25%	1.00%	2.30%	4.00%	7.00%
GHG30	4210	4130	3930	3810	3650
GHG40	3610	3540	3390	3310	3170
GHG50	3150	3090	2970	2920	2790

Total SO_2 (thousand ton)					0.51
GHG cap	Methane leakage rate				
	0.25%	1.00%	2.30%	4.00%	7.00%
GHG30	2150	2140	2100	2070	1930
GHG40	1400	1370	1280	1280	1310
GHG50	1220	1240	1230	1200	1210

Total NOx (thousand ton)					0.74
GHG cap	Methane leakage rate				
	0.25%	1.00%	2.30%	4.00%	7.00%
GHG30	6350	6340	6290	6260	6090
GHG40	5970	5890	5660	5550	5350
GHG50	5370	5280	5030	4920	4740

Fig. 7.

Electricity production by plant type, natural gas and water consumption, and system-wide emissions in 2050 with varying GHG cap levels and methane leakage rates

Table 1

Scenario assumptions in 2050. GHG50 is run under various assumptions related to these 20 factors

	Factor	Very low	Low	Default	High	Very high
1	Hurdle rate on BIOIGCC-CCS (%)	–	–	10	–	44
2	Natural gas price ($/thousand m^3)	173	–	308	–	438
3	Hurdle rate on nuclear (%)	–	10	15	25	44
4	Investment cost for NGCC-CCS (M$/GW)	1255	1325	1428	1782	2133
	CO_2 retrofit cost for NGCC ($/KWh)	0.027	0.031	0.041	0.054	0.072
5	CO_2 capture rate for NGCC-CCS and CCS retrofit in NGCC (%)	66	70	85	90	95
6	NGCC-CCS efficiency (energy out/energy in) (%)	40	43	45	49	–
	CCS retrofit efficiency (%)	75	80	84	91	–
7	CCS retrofit cost for NGCC ($/KWh)	–	–	0.041	0.049	0.066
8	Hurdle rate for NGCC-CCS (%)	–	5	10	25	45
	Hurdle rate for CCS retrofit in NGCC (%)	–	5	10	15	20
9	Battery storage requirement for renewables (GW storage per GW of variable renewables) (%)	0	7	14	–	–
10	CO_2 storage cost ($/t$CO_2$)	4.90	7.30	9.70	12.1	14.5
11	Electricity storage investment cost (M$/GW)	1000	2000	4623	–	–
12	Methane leakage rate during extraction (%)	0.25	1.00	2.30	4.00	7.00

		No range
13	Max. electrification of light duty vehicles (LDVs)	Fixed 99% of LDV fleet purchases
	Battery electric vehicles	49%
	Plug-in electric vehicles	50%
14	Max. wind and solar	No upper bound on solar + 27,778 billion KWh upper bound on wind + 2083 billion Kwh lower bound on total wind and solar electricity generation
15	No BIOIGCC-CCS	No biomass with CCS plant option
16	No CCS gas retrofit	No CCS retrofit option for natural gas combined-cycle plants
17	No lifetime extension on existing coal	No investment option to extend 50-year lifetime of existing coal plants
18	No gasification technologies	No biomass- and coal-IGCC plant options
19	No lifetime extension on existing nuclear	No investment option to extend 40-year lifetime of existing nuclear plants
20	High nuclear output	833 billion KWh lower bound limit on electricity from nuclear plants

The default values associated with each factor are based on the EPAUS9r-14-v1.5 database. The default values represent the BAU assumptions. All costs are based on 2005$