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Sensitivity of natural gas deployment in the US power sector to future carbon policy expectations

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ABSTRACT

One option for reducing carbon emissions in the power sector is replacement of coal-fired generation with less carbon-intensive natural gas combined cycle (NGCC) generation. In the United States, where there is abundant, low-cost natural gas supply, increased NGCC deployment could be a cost-effective emissions abatement opportunity at relatively modest carbon prices. However, under scenarios in which carbon prices rise and deeper emissions reductions are achieved, other technologies may be more cost-effective than NGCC in the future. In this analysis, using a US energy system model with foresight (a version of the National Energy Modeling System or “NEMS” model), we find that varying expectations about carbon prices after 2030 does not materially affect NGCC deployment prior to 2030, all else equal. An important implication of this result is that, under the set of natural gas and carbon price trajectories explored here, myopic behavior or other imperfect expectations about potential future carbon policy do not change the natural gas deployment path or lead to stranded natural gas generation infrastructure. We explain these results in terms of the underlying economic competition between available generation technologies and discuss the broader relevance to US climate change mitigation policy.

1. Introduction

Among the sectors that may contribute to greenhouse gas (GHG) emissions reduction under commonly cited scenarios of energy system transformation, the power sector has been identified as one with significant cost-effective emissions abatement potential, due in part to the availability of commercial alternatives to conventional coal-fired generation (Clarke et al., 2014). Generation from natural gas combined cycle (NGCC) plants is one such alternative, among others. NGCC power plants are considerably less carbon-intensive than coal-fired power plants due to the lower carbon-intensity of natural gas fuel and the higher operating efficiencies of combined cycle technology.

Despite its lower carbon-intensity relative to coal, natural gas has been closely scrutinized as a climate change mitigation option for a number of reasons, including concerns about its potential life cycle emissions when fugitive methane emissions (particularly from production and transmission) are considered (e.g., Alvarez et al., 2012). However, a number of studies have found that the overall GHG-intensity of NGCC plants used in power generation is likely to be considerably lower than that of coal-fired generation, regardless of whether the natural gas is produced from “conventional” or “unconventional” (i.e. shale) basins (Hultman et al., 2011; Jiang et al., 2011; Stephenson et al., 2011; Weber and Clavin, 2012; Laurenzi and Jersey, 2013; Heath et al., 2014).[1] Moreover, many estimates now suggest that several decades of US natural gas supply is available below \$4 per MMBTU (Cole et al., 2016; Paltsev et al., 2011).[2] Taking into account these findings about emissions and costs, several studies have concluded that natural gas – in particular, increased generation from NGCC – may be the dominant near-term response to potential carbon policy in the US power sector (Paltsev et al., 2011; Logan et al., 2013; Newell and Raimi,

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[1] More generally, the relative contributions of different methane sources (including both natural and anthropogenic sources) to total emissions vary spatially and temporally. The issue of source attribution has been a focus of ongoing scientific research. Many of these studies have used atmospheric measurements to estimate emissions and associated uncertainties from different sources in particular regions and over specific time intervals (Peischl et al., 2015; Karion et al., 2015; Petron et al., 2014; Zavala-Araiza et al., 2014). Estimates of uncertainty in these studies can be significant. Moreover, recent studies have suggested that a relatively small number of sources in a given region could be responsible for a disproportionate share of methane emissions (Brandt et al., 2014, Brandt et al., 2016). Taken as a whole, recent research remains consistent with earlier studies (cited above) regarding the overall GHG-intensity of natural gas but calls attention to some of the challenges in characterizing methane sources at finer scales and further reducing uncertainties.

[2] See also: http://news.ihsmarkit.com/press-release/north-americas-unconventional-natural-gas-resource-base-continues-expand-volume-and-de.

http://dx.doi.org/10.1016/j.enpol.2017.08.012
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2014; Ross and Murray, 2016).

At the same time, conditions favorable to NGCC deployment have brought to the fore questions about whether such deployment is consistent with long-term scenarios of energy system transformation designed to mitigate climate change (Healy and Jaccard, 2016), which are similar to questions that have been asked about the role of coal-based generation (Johnson et al., 2015; Bertram et al., 2015). Of the studies that have focused on the role of natural gas (without carbon capture and storage), several studies that rely on physical models or model meta-analysis have ostensibly reached different conclusions, with some suggesting that expanded natural gas deployment could be consistent with broader climate change mitigation goals (Zhang et al., 2016; Levi, 2013), and others suggesting the opposite (Erickson et al., 2015; Pfeiffer et al., 2016).

Among those studies that have explicitly conducted economic modeling, some have examined the role of natural gas under "business as usual" without examining the implications of carbon policy (McJeon et al., 2014), while others have considered carbon policy but not foresight (Logan et al., 2013).[3] Some multi-model studies, such as those conducted as part of the AMPERE project (Kriegler et al., 2015), have considered natural gas deployment in the context of several longer-term climate change mitigation goals, but results are inconclusive about the role of natural gas and challenging to diagnose because models differ with respect to many assumptions (Riahi et al., 2015).[4]

More specifically, comparisons across models in the AMPERE study suggest a wide range of potential natural gas outcomes in 2030 for power sector emissions reductions in that year that are consistent with significant climate change mitigation, due to variability in other assumptions (see Fig. 1). In particular, while coal generation decreases monotonically as emissions are reduced (panel a), natural gas generation increases in some models as the system transitions from higher emissions to lower emissions (movement from right to left in panel b), even when the set of scenarios is restricted to those that represent the model-derived optimal path to a given atmospheric stabilization goal. These results suggest that the role of natural gas in the US power sector in commonly cited emissions reduction scenarios is ambiguous and highlight the need for more targeted assessment.

Despite the ambiguity observed in model comparisons such as the one above, concerns have been raised that reliance on natural gas in the early years of a national program to reduce power sector emissions could make it more challenging to meet longer-term emission reduction goals in the power sector, if those goals are significantly more stringent than nearer-term ones (i.e., if carbon prices rise significantly over time, or equivalently, if emissions caps in a tradable system ratchet downward over time). For example, in promulgating the "Clean Power Plan" (CPP), the US Environmental Protection Agency (EPA) expressed commenters' concerns that "inclusion of new NGCC capacity in setting the BSER [Best System of Emission Reduction] or in compliance could negatively impact ratepayers over the long-term by sending the wrong signal to industry and resulting in stranded assets if, in the future, carbon emissions become more expensive…"[5]

To help reduce uncertainty about the role of natural gas in carbon mitigation, this study develops scenarios that are suited to this exploration and could be relevant to forthcoming decisions faced by policymakers in the United States. Specifically, it considers carbon prices prior to 2030 that yield emissions outcomes consistent with the CPP as projected by EIA (EIA, 2017); it considers a case in which the carbon price remains at this level after 2030, as well as one in which it continues to rise indefinitely; and it adopts natural gas prices consistent with other available projections (EIA, 2017).[6]

The remainder of this paper proceeds as follows. Section 2 introduces the modeling platform, approach and scenarios. Section 3 describes the results. Section 4 provides an explanation of the results in terms of underlying technology competition and considers the sensitivity to other assumptions. Section 5 concludes with a discussion of broader policy implications.

2. Methods

2.1. Model description

We use a version of the National Energy Modeling System (NEMS) developed by the US Energy Information Administration (EIA), which we refer to as "R-NEMS" to emphasize its research application in this context.[7] R-NEMS represents the entire US energy system, including oil, natural gas and coal supply sectors, electricity and other conversion sectors, and the residential, commercial, industrial and transportation demand sectors. Each sector is represented by a self-contained module, but the model is run in an integrated fashion so that relevant interactions between the sectors – such as the interaction between natural gas supply and demand from the electricity sector – can be captured. R-NEMS projects key energy system variables annually on a regional basis for the contiguous United States through 2050.

For this study, the Electricity Market Module (EMM) of R-NEMS is the most relevant.[8] Within the EMM, capacity expansion and dispatch decisions are handled sequentially. In any given year, the model determines the capacity expansion solution (capacity additions and retirements by plant type and region) in the 22-region EMM for the following year (see Fig. S4 for a map of the EMM regions). It does so by minimizing the net present value of total costs (capital, operating and fuel costs) for the next 30 years.[9] Importantly, during this "look-ahead" process, the model incorporates expectations about future fuel

[3] See also Cole, W., R. Beppler, O. Zinaman, J. Logan. "Considering the Role of Natural Gas in the Deep Decarbonization of the U.S. Electricity Sector," NREL Technical Report, February 2016. Available at: http://www.nrel.gov/docs/fy16osti/64654.pdf.

[4] A related model comparison study was conducted by Stanford's Energy Modeling Forum (EMF), which focused on a diverse set of topics related to natural gas (Huntington, 2016).

[5] See Federal Register, Vol. 80, No. 205, p. 64903.

[6] In this study, we use the CPP only as a benchmark of potential future policy stringency and do not explicitly represent compliance with the CPP. This benchmark is useful, in part, because EIA has represented the CPP in the Annual Energy Outlook (AEO) 2017 Reference Case, so details of this scenario are readily available. It is also worth noting that this analysis is focused on the US electricity system through 2050. For this reason, the resulting US electricity emissions trajectories in this study could be consistent with a number of global long-term temperature targets, depending on assumed actions in other sectors, across other world regions and after 2050, all of which are outside the scope of this study. For some additional context, the Intergovernmental Panel on Climate Change (IPCC) states that "in the majority of low-stabilization scenarios [430–530 ppm CO2e], the share of low-carbon electricity supply (comprising RE, nuclear and CCS) increases… to more than 80% by 2050″ (Bruckner et al., 2014). This implies that electric sector emissions would approximately be reduced by the same amount or more (depending on whether these scenarios also include the displacement of coal-fired generation with natural gas). For comparison, electric sector emissions in the Rising Price Case discussed in this paper are reduced 74% by 2050 relative to 2005. The sensitivity of our results to assumptions about the carbon price path, and thus to assumed policy stringency, is discussed in Section 4.

[7] Full NEMS model documentation can be found at https://www.eia.gov/forecasts/aeo/nems/documentation/. Note also, that our version differs from the version used by EIA and that the views expressed in this paper do not necessarily reflect those of EIA.

[8] However, since the model is run in an integrated fashion in this study, other modules provide important information to the EMM. For example, natural gas prices delivered to the power sector are determined, in part, through iteration with the Oil and Gas Supply Module (OGSM). Greater demand for natural gas by the electric sector can increase natural gas prices in the short run, reflecting movement along the short-run supply curve, but it can also provide a signal for greater natural gas investment that will increase supply and, in turn, put downward pressure on prices in the longer run. Similarly, the overall demand for electricity and the "shape" of that demand over the course of a year are determined by the level and shape of demand across the full suite of electricity end uses, primarily in the buildings and industrial sectors.

[9] Economic retirements occur when the net present value of the going-forward costs (fixed and variable operating costs) of existing capacity exceed the net present value of the going-forward costs (fixed and variable operating costs, as well as capital costs, if the relevant alternative is new generation capacity) of alternatives that can provide the same service.

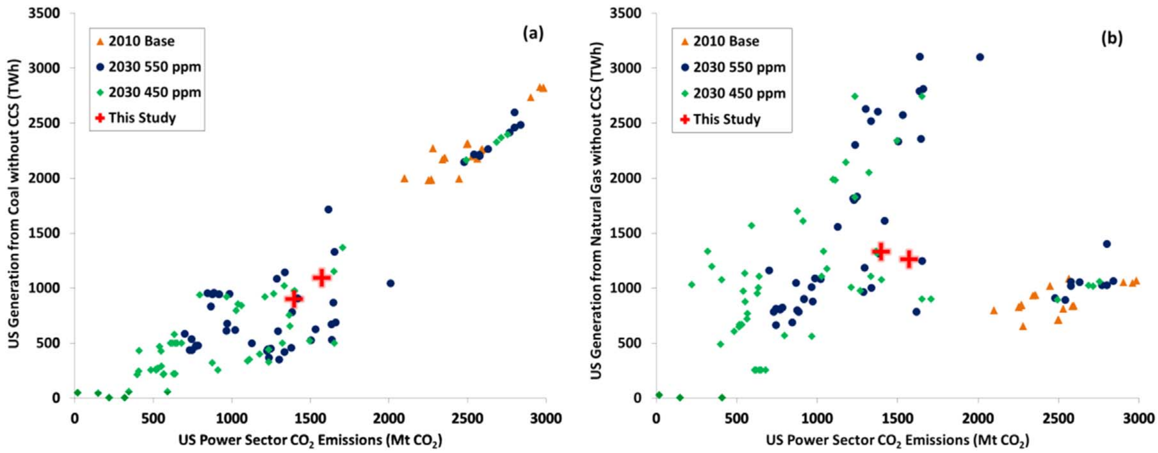

Fig. 1. US electricity generation from coal without carbon capture and storage (panel a) and natural gas without carbon capture and storage (panel b) plotted against US power sector CO_2 emissions. Results are taken from the AMPERE model comparison study that included nine energy-economy, computable general equilibrium, and integrated assessment models (Kriegler et al., 2015). Each modeling group considered a common set of scenarios, including a suite of different technology cases, each of which was run subject to different atmospheric concentration targets (Riahi et al., 2015). Orange markers in this figure indicate conditions in the models in 2010, blue markers indicate outcomes in 2030 from "optimal policy" cases designed to achieve atmospheric stabilization at 550 ppm CO_2e, and green markers indicate outcomes in 2030 from "optimal policy" cases designed to achieve atmospheric stabilization at 450 ppm CO_2e. The red crosses indicate outcomes in 2030 from the two main scenarios developed and discussed in this study. Note that only scenarios with power sector emissions less than 3000 Mt CO_2 are shown in these charts. For underlying data associated with the AMPERE project, see: http://ampere-project.eu/web/.

and carbon prices, and as such, includes foresight about the future when making investment decisions.[10] Once the capacity solution is known for a given year, the model dispatches the system to minimize short-run marginal costs (variable operating expenses, including fuel costs). Once both the capacity and dispatch solutions are known, the process begins again, recursively propagating the electricity system forward in time. In this way, R-NEMS represents key aspects of the real power sector, including long-run planning decisions and short-run operating decisions.

The set of technologies considered by the EMM includes the full suite of existing technologies, with detail about the existing fossil-fueled generation fleet derived from EIA survey data.[11] Because there is significant heterogeneity in the operating characteristics of the existing fossil-fueled generation fleet, this detail is important for capturing particular operating decisions (such as how much coal and NGCC will be dispatched in a given region), as well as planning decisions (such as how much coal will retire in a given region). With respect to new plants, the model includes stylized representations of most major technology classes that are likely to be deployed over the next several decades, including coal with carbon capture and storage (CCS), natural gas combined cycle (NGCC) with and without CCS, nuclear, wind, solar photovoltaic (PV), concentrating solar power (CSP), geothermal, and biomass, among others.[12]

Because this study considers the role of NGCC in the electricity mix under scenarios in which this technology is often competing with variable renewable energy (VRE) sources, such as wind and solar PV, it is also worth considering aspects of the model that are relevant to how these technologies contribute to the operation of the electricity system. A common characteristic of VRE sources is that they are not "dispatchable," which means that they are only available to generate when resource exists, for example when there is sufficient sunlight to power photovoltaic capacity or sufficient wind to drive wind turbines. As a result, additional dispatchable capacity must be available to serve load when resources are not available, or the system must be able to balance load in other ways such as by altering power flows across or within regions or through demand-response measures.

The EMM divides annual load into nine "time slices" in which supply and demand must be balanced assuming an average capacity factor for each VRE technology for each time slice based on the expected pattern of generation for that technology in the hours represented by the time slice. In addition, because VRE sources have variable output, their contribution to the planning reserve margin is typically less than that of traditional dispatchable resources. As a result, in some cases, dispatchable sources must be retained to ensure that the planning reserve margin is met during all peak hours of the year. The EMM also represents spinning reserve requirements that increase as more VRE capacity is added to the grid.[13]

The need to balance load in all time slices in the model and the

[10] These price expectations are derived from the solutions from previous model iterations. However, in this study, the carbon price trajectory is specified exogenously, so expectations about future carbon prices simply reflect these user assumptions. Note that foresight does not take into account changes in future technology capital costs. More generally, foresight in the EMM is included within a broader recursive-dynamic solution framework. In any given solution year (t), the model looks ahead 30 years by dividing this period into several discrete time blocks (two 1-year blocks and one 28-year block). The capacity expansion solution for the second year of this 30-year window becomes the model solution for year $t+1$, and the process then repeats. The solution derived from this rolling foresight approach can differ quantitatively from the one derived from a perfect foresight approach (simultaneous inter-temporal optimization), but both qualitatively capture expectations about the future when solving for earlier periods. See Section S2 for additional discussion.

[11] The EMM uses various levels of aggregation of individual units or plants for different purposes. For capacity planning purposes, existing coal, nuclear, combined cycle and oil and gas steam units are combined into model plant "bins" based on characteristics such as heat rate and pollution control configuration. These bins may consist of a single plant or several plants with similar characteristics. For purposes of dispatch, the aggregation is generally similar but more granular for some technologies, such as for natural gas combustion turbines.

[12] In this study, coal generation without CCS is not allowed to deploy due to the inclusion of the New Source Performance Standards (NSPS) for Electric Generating Units (EGUs) promulgated by EPA under Section 111(b) of the Clean Air Act. R-NEMS includes an option for coal CCS retrofits in addition to new coal with CCS, but it does not include a similar retrofit option for natural gas CCS. The inclusion of such an option could provide an additional pathway for natural gas to compete under more stringent carbon policy, but this topic is out of scope for this paper. R-NEMS also includes existing storage capacity (pumped hydro) in the electric sector, but it does not consider the addition of new storage capacity. New nuclear capacity is not allowed in NY-Westchester, Long Island and California (see Fig. S4 for a map of EMM regions).

[13] The potential for new storage is not represented because the temporal resolution of the model is not sufficient to fully represent the way that storage would operate in a real system. Depending on the cost of storage, its hypothetical inclusion could alter the deployment pathways of VRE and NGCC. However, such scenarios are special cases of a broader class of technology sensitivities, which are considered in Section 4.

requirement to satisfy planning and spinning reserve requirements capture some important features of the real world that affect technology selection, but recent analysis has suggested that the temporal resolution of the EMM is not sufficient to capture the full extent of curtailments (periods of excess supply) that would be expected under large amounts of solar PV deployment.[14] Modifications to explicitly account for curtailments have been introduced in the 2017 Annual Energy Outlook (AEO) and are thus included in our version of R-NEMS.[15] While other available electricity system models offer more detail with respect to these aspects of VRE integration,[16] R-NEMS incorporates other features that are important for this study, including national (US) scope, foresight with respect to electricity planning decisions, detail about the existing fossil fuel-fired generation fleet relevant to both electricity system planning and operation, explicit treatment of natural gas supply that captures changes in fuel prices as demand changes, publicly available model code, and well-documented assumptions. As such, the features of R-NEMS that are well-suited to this study outweigh those that are limiting.

2.2. Description of scenarios

In this study, our version of NEMS (R-NEMS) is based off of EIA's (2017) AEO Reference Case with some adjustments. Key assumptions are described in more detail in Section S1. Specifically, Fig. S3 compares natural gas price trajectories in our scenarios to the AEO 2017 Reference Case. Table S1 provides initial capital costs for the most relevant technologies, and Table S2 provides fixed O & M costs, variable O & M costs, and heat rates for relevant technologies. Finally, Table S3 provides information about how extensions to the tax credits for wind and solar enacted in December 2015 are represented.

The AEO 2017 Reference Case included a stylized representation of the "Clean Power Plan" (CPP). Because our interest is more general, we have removed the CPP and instead imposed carbon policy using an electric sector carbon price. Both scenarios in this study include a common carbon price trajectory applied to the power sector between 2020 and 2030. When this carbon price is held constant after 2030, the resulting emissions trajectory is consistent with the emissions reduction that would be anticipated under the CPP prior to 2030, as projected by EIA in the AEO 2017 Reference Case (EIA, 2017).[17] One carbon price trajectory that achieves this consistency starts at \$8 per metric ton CO_2 (in 2016 dollars) in 2020 and rises at 8% real per year, reaching \$18 by 2030.[18]

The two main cases considered in this paper adopt all of the assumptions above and differ only in what they assume about the carbon price trajectory after 2030. The "Capped Price Case" assumes that the carbon price remains constant after 2030, which reflects a world that does not expect or account for potentially increasing future stringency of carbon policy. The "Rising Price Case," by contrast, assumes that the carbon price continues to rise at the same rate (8% real per year) after 2030 (see Fig. S1 for a comparison of the carbon price trajectories and Fig. S2 for a comparison of the resulting emissions trajectories).[19] While the model projection period ends in 2050 (at which time the carbon price in this case reaches \$84 per ton), the capacity planning algorithm (discussed above) incorporates the continued escalation through 2080.[20] This assumption reflects a world that expects and accounts for increasing stringency of carbon policy. This scenario design – in particular, harmonizing all assumptions except for the carbon price trajectory after 2030 – allows us to isolate the effects of post-2030 expectations on pre-2030 investment.

3. Results

The evolution of the electricity system under both the Capped Price Case and the Rising Price Case is shown in Fig. 2 (panels a and b) as the projected change in generation relative to 2015.[21] Showing generation in this format calls attention to which types of generation are expanding relative to current levels and which are decreasing or not changing at all. While the focus of this paper is on investment (i.e., changes in capacity, which are shown in panels c and d), generation provides a sense of how the production of electricity changes under different carbon price trajectories, which is more closely related to how emissions change.

There are several common features across the two cases. First, regardless of whether the carbon price continues to escalate beyond 2030, NGCC generation increases over the time horizon considered here, except between 2045 and 2050 in the Rising Price Case, during which time NGCC generation decreases in response to the higher imposed carbon price. Second, in both cases, the increase in generation from natural gas largely displaces generation from coal. Third, generation from nuclear sources declines slightly relative to current levels in both cases due to ongoing retirements of existing capacity, with the exception of the final periods of the Rising Price Case, during which time generation from new nuclear generation more than offsets the decline in generation from retiring existing capacity.

The most significant difference between the cases is the evolution of generation from wind and solar PV. Generation from these sources increases in both cases, but increases more in the Rising Price Case. This additional generation from VRE sources also displaces coal generation, with coal generation decreasing in total by ~1300 TWh in 2050 in the Rising Price Case but by ~300 TWh in the Capped Price Case.

Changes in capacity (shown in panels c and d of Fig. 2) provide a clearer sense of how underlying investment changes. Once again, there are several similarities between the cases. First, the change in NGCC capacity is similar between the cases, with 160–180 GW added by 2050, not including capacity with CCS. Second, the increase in NGCC and VRE capacity displaces existing coal capacity. Third, nuclear capacity

[14] See Wood, F. "The Consideration of PV Curtailments in NEMS: Addressing the Duck Problem," presentation at the Electric Capacity Expansion Modeling Workshop: Treatment of Variable Renewable Energy, July 11, 2016. Presentation available at http://www.eia.gov/renewable/workshop/.

[15] More generally, a number of questions have been raised about the accuracy of EIA forecasts, particularly about the potential for underestimation of future renewable energy deployment based on the accuracy of past forecasts. EIA considered and responded to some of these concerns in a published report, which includes citations to the underlying sources in which those concerns were originally expressed: https://www.eia.gov/outlooks/aeo/supplement/renewable/. Similar questions could be raised about the accuracy of natural gas price forecasts or other model outputs. Due to the uncertainty inherent in future technology costs, fuel prices and other features of the real world, we explicitly discuss the sensitivity of our findings to such input assumptions in Section 4.

[16] For example, see documentation for the NREL ReEDS model: http://www.nrel.gov/docs/fy17osti/67067.pdf.

[17] For the purposes of this study, the CPP is only used as one possible benchmark of the potential stringency of future carbon policy, so the main insights of this analysis do not depend on the way in which pending CPP legal issues are resolved.

[18] A rising price path is consistent with emissions reductions that increase over time. It is also consistent with tradable policy instruments that allow temporal flexibility in compliance (Rubin, 1996). Although other carbon price trajectories (for example, those that rise at different annual rates) could also achieve broad consistency with the projected CPP emissions trajectory prior to 2030, the choice of 8% for the carbon price escalation rate allows the price to increase significantly after 2030 (to test the primary hypothesis explored in this analysis about the effect of higher future carbon prices) while still being comparable to rates used in modeling tradable emissions systems. See, for example, http://www.eia.gov/analysis/requests/2008/s2191/pdf/sroiaf(2008)01.pdf.

[19] For comparison to other published scenarios, the electric sector emissions reductions in the Rising Price Case are 42% in 2030, 57% in 2040 and 74% in 2050 compared to 2005. The emissions reductions in the Capped Price Case are 30–35% over the period 2030–2050 compared to 2005.

[20] While it would be useful to put these carbon prices in broader context, this is challenging because of the uncertainties in estimates of both the costs and benefits of climate change mitigation. For comparison, the IPCC has assessed estimates of climate change impacts (Arent et al., 2014) as well as estimates of abatement costs from model scenarios designed to realize different end-of-century climate change mitigation goals (Clarke et al., 2014).

[21] This figure does not include generation from end uses, such as distributed PV in the residential sector.

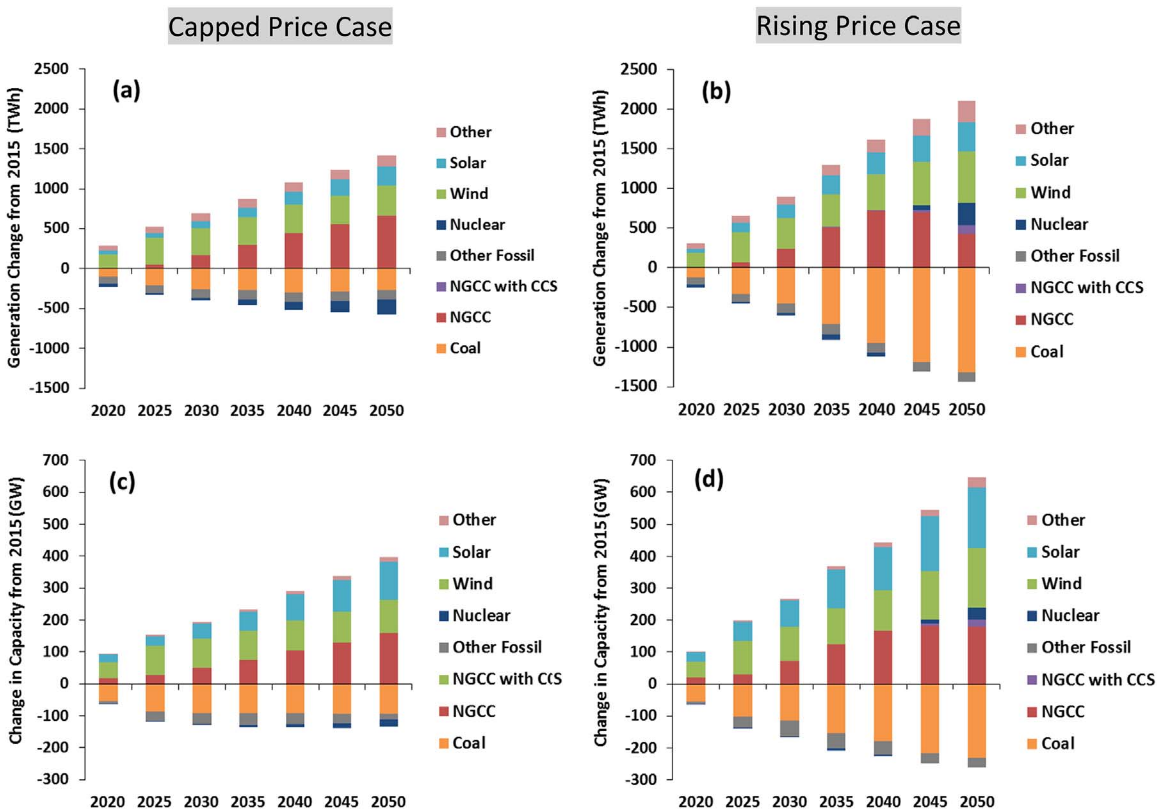

Fig. 2. Change in generation relative to 2015 (panels a and b) and change in capacity relative to 2015 (panels c and d) for selected technologies in the two cases developed in this study. The Capped Price Case is shown in panels (a) and (c), and the Rising Price Case is shown in panels (b) and (d). "Other Fossil" includes generation or capacity from natural gas combustion turbines (NGCTs) and oil and natural gas steam generation units. "Other" includes generation or capacity from all remaining sources.

decreases slightly except in the later years of the Rising Price Case, when new capacity additions offset capacity retirements.

Mirroring the results for generation, the most significant difference between the two cases is the amount of VRE capacity that is added. For these technologies, the values in panels (c) and (d) appear larger than the respective amounts in panels (a) and (b) because more capacity per unit of generation is needed from these sources, due to their relatively lower annual capacity factors.

To answer the key question posed by this study – whether expectations about rising carbon prices beyond 2030 deter investment in NGCC prior to 2030 – it is helpful to view the NGCC capacity and generation outcomes side-by-side for both cases for several representative years. Table 1 shows these outputs for 2015, 2030, and 2050 (the last year of the projection period). Several insights follow from this table. First, NGCC generation increases by a similar amount over the projection period in both cases. Second, this increase in generation is supported by an increase in NGCC capacity in both cases. Third, and most importantly, the amount of NGCC capacity added in 2030 is comparable across the cases.

Table 1
NGCC generation, capacity and capacity factors for the two cases developed in this study in 2015, 2030, and in 2050 (the last year of the projection period).

	Generation (TWh)			Capacity (GW)			Capacity Factor		
	2015	2030	2050	2015	2030	2050	2015	2030	2050
Capped Price Case	1092	1260	1753	226	277	386	55%	52%	52%
Rising Price Case		1328	1525		299	406		51%	43%

This last finding suggests that anticipation of rising carbon prices does not deter near-term NGCC deployment relative to what it would have been without such anticipation (i.e., in the Capped Price Case). Whether or not the stringency of carbon policy is expected to continue increasing after 2030 or to remain roughly constant, NGCC deployment is comparable, even when considering the full net present value of costs in both cases. Moreover, the amount of natural gas capacity added in the Rising Price Case actually exceeds the amount of capacity in the Capped Price Case. While this effect is relatively small, it suggests that in some scenarios with higher VRE penetration, NGCC capacity is desirable for its capacity value – that is, its ability to provide energy during periods of time when generation from solar and wind resources is low.

This additional role for NGCC in scenarios with higher VRE penetration is also highlighted by the evolution of NGCC capacity factors in the two cases. In Table 1, it is clear that the average capacity factor of the NGCC fleet in the Rising Price Case is lower in 2050 than it is in 2030. The trajectory of capacity factors across these cases suggests that, in some scenarios, NGCC benefits from its flexibility to partially shift between generation and capacity value streams over time in response to market and policy conditions.

4. Discussion

A key takeaway from these results is that deployment of new NGCC prior to 2030 is largely unaffected by expectations of carbon policy stringency after 2030. To the extent that NGCC deployment is affected by higher future carbon price expectations, it is positively affected (there is more NGCC capacity in the Rising Price Case). Before considering the implications of this finding in more detail, it is important to provide an explanation in terms of the underlying assumptions and to consider the robustness of results to assumptions not explicitly varied in the main cases.

The underlying cost competition among technologies represented in the model can provide a first-order explanation of results. As discussed earlier, technologies compete on the basis of total cost in R-NEMS, taking into account differences in performance (e.g., dispatchability) and in the services that they provide (e.g., differential contributions to planning and spinning reserves). In addition, the model takes into account expectations about the future when making current investment decisions.

To consider the effect of foresight, it is worth noting that, if the carbon price trajectory were flat (the carbon price in the Capped Price Case can be viewed as approximately flat), then the effect of foresight would be minimal, because the carbon price at a given time (*t*) approximately reflects the average future carbon price, which is the effective price used to make decisions at time *t*. However, when the carbon price rises monotonically (as in the Rising Price Case), then the effect of foresight can be more significant, because the effective carbon price used to make decisions at time *t* could be considerably higher than the instantaneous carbon price at time *t*.

Section S3 suggests that, under the assumptions adopted in the Rising Price Case, the anticipation effect is approximately a decade. That is, the effective carbon price is approximately the instantaneous carbon price ten years in the future. This result implies that the relevant carbon price is the *effective* price in year *t* (approximated by the instantaneous price in year $t+10$), rather than the instantaneous carbon price in year *t*. In the Rising Price Case, the effective carbon price reaches ~\$80 per ton CO_2 shortly after 2040 (because the instantaneous price reaches ~\$80 in 2050), after which policy-induced new NGCC additions slow considerably.[22] This result implies that, at an effective price of approximately \$80 per ton CO_2, the model is indifferent between NGCC and the nearest emissions-free alternative, after taking into account relevant differences in cost and performance between the technologies, and noting that results may vary regionally.

Because the NGCC deployment path can be explained in terms of the year in which the costs for NGCC and the most competitive emissions-free alternative are expected to cross (when costs include the imposed carbon price), and because this crossover year depends on the particular assumptions adopted, it is natural to explore the sensitivity to these assumptions. For example, shifting the natural gas price or carbon price trajectory upward would bring forward the crossover year, as would shifting the solar PV cost (or other relevant technology cost) trajectory downward. Similarly, increasing the rate of carbon price escalation, natural gas price escalation or solar PV cost decline would have comparable effects. The latter conclusion follows from the fact that the anticipation effect (t^* in Eq. S3) is not strongly affected by the escalation rate itself. Therefore, the primary consequence of changing the escalation rate would be to shift the crossover year, just as moving the carbon price upward or downward would shift the crossover year.

To explore the consequences of such sensitivities more explicitly, one may consider what would happen if the crossover year were not several decades away (as in the Rising Price Case), but occurred at some earlier time (say in 2030). This could occur under different assumptions about natural gas prices, carbon prices, solar PV costs, or other emissions-free technology costs. In this version of a rising case, NGCC would likely not widely deploy initially (in 2020) because the initial *effective* carbon price (instantaneous carbon price in 2030), would render NGCC approximately equal in cost to its nearest competitor (by assumption). However, the capped version of this case would face the same effective carbon price initially (instantaneous carbon price in 2030), so NGCC would not be widely deployed in this case either, meaning that the difference between the two cases would be small.[23] The same general reasoning can be applied to other hypothetical cases in which the crossover year is varied.

This lack of sensitivity to the crossover year (whether driven by changes in the level or slope of the trajectories of any of the key assumptions – natural gas prices, carbon prices, or technology costs) is a key finding of this study. It follows from the fact that, if trajectories of the relevant parameters are smoothly varying and aligned for the first ten years, then the *effective* values of those parameters in year *t* (i.e., their instantaneous values in year $t+10$) are initially identical. If the set of effective values is one that renders NGCC uncompetitive initially, then neither the rising nor the capped version of this case will significantly deploy NGCC, so the cases will be effectively identical with respect to NGCC deployment. If the set of effective values is one that renders NGCC initially cost-competitive, then the rising price version of this case will traverse part of the parameter space that is favorable to NGCC deployment before entering a part of the space that is not. The capped price version of this case will remain in the region of the parameter space in which it began. Therefore, because the rising price version traverses more of the parameter space that is favorable to NGCC, it will tend to deploy more NGCC than the capped price version (the effect observed in the cases discussed in this study).

The finding above is quite general, although it could be challenged by considering scenarios in which key parameter trajectories are not smoothly varying. For example, one may consider a scenario in which the carbon price is low (e.g., \$10 per ton) for ten years, but jumps to a very high value (e.g., \$100 per ton) after that. In this case, the effective initial price (the instantaneous price in year $t+10$) will be the higher price. If compared to a case in which the carbon price is low indefinitely, one could find that the case with a discontinuity deploys *less* NGCC than the case without, suggesting that the choice of NGCC in the near-term would not be robust to future expectations. However, the assumption that relevant functions vary smoothly – or that discontinuities are not sufficiently large to drive the outcomes discussed in the extreme example above – is reasonable, given the current context of natural gas supply in the United States, past experience with technology learning, and the nature of institutions that will determine the evolution of carbon policy.[24]

5. Conclusions and policy implications

By developing a small number of scenarios in a version of a well-known US energy system model, this paper has explored the extent to which foresight about potential carbon policy stringency after 2030 is likely to affect NGCC deployment prior to 2030. We conclude that, under plausible natural gas and carbon price trajectories for the United States, deployment of NGCC in the power sector is a cost-effective abatement option over the projection period. We also conclude that, under the range of conditions explored, different expectations about potential future carbon policy do not materially affect choices about NGCC prior to 2030. Put differently, while alternative assumptions

[22] Policy-induced additions (i.e., those attributable to the carbon price) can be approximated by taking the difference between total additions in a case that includes a carbon price (Capped Price Case or Rising Price Case) and the total additions in an identical case that does not include a carbon price. This subtraction controls for additions that occur due to other factors, such as load growth.

[23] To test this hypothesis, we performed an explicit sensitivity analysis using R-NEMS in which the natural gas resource assumptions were varied to reflect those in either the AEO 2017 Low Oil and Gas Resource and Technology Case (that results in higher realized natural gas prices) or the AEO 2017 High Oil and Gas Resource and Technology Case (that results in lower realized natural gas prices). We find weaker overall NGCC deployment (greater overall VRE deployment) in the former and greater overall NGCC deployment (lower overall VRE deployment) in the latter, but comparable (or more) NGCC investment in the Rising Price Cases compared to the Capped Price Cases. These results support the reasoning above about why changes in the carbon price trajectory alone would not be expected to lead to significant differences in NGCC investment prior to 2030.

[24] Some authors have also suggested that path-dependency in the energy system can lead to economically inferior outcomes, just as it can in other sectors of the economy whose evolution is driven by the diffusion of technology (Unruh, 2000). Although some aspects of path-dependency are captured by models, including R-NEMS, a full examination of this issue is outside the scope of this paper.

(including alternative assumptions about natural gas prices, carbon prices, or technology costs) may affect the overall magnitude of NGCC deployment, different expectations about how quickly carbon prices will increase (or other parameters will change) are not alone sufficient to materially affect NGCC investment prior to 2030.

When viewed in the context of future policy decisions, these results suggest that flexible, technology-neutral policy instruments with national stringency comparable to recently considered policies (for which the Capped Price Case serves as a proxy) would lead to significant deployment of NGCC. Moreover, in a hypothetical case with increasing stringency after 2030 (for which the Rising Price Case serves as a proxy) a similar amount of NGCC would be deployed. By comparing these two outcomes, one may conclude that, under the assumptions used in this study – and variants that do not include significant discontinuities – limited foresight about potential future carbon price increases will not lead to stranded natural gas generation infrastructure.[25] Rather, flexible policy instruments implemented to achieve emissions reductions comparable to the Capped Price Case are likely to yield solutions that are consistent with both stable and increasing carbon policy stringency after 2030.

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Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at http://dx.doi.org/10.1016/j.enpol.2017.08.012.

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[25] The definition of a "stranded asset" deserves more attention than is possible in this paper. For the purposes of this paper, an asset is "stranded" if future revenues do not offset upfront capital (and ongoing operating expenses) prior to retirement. In R-NEMS (and in other linear optimization frameworks), installed capacity will, by assumption, always recover costs, because prices for energy and/or capacity will rise to a point at which all investment costs are recovered. As a result, capacity in our scenarios is never stranded assuming the actual policy conditions follow the assumptions. We further conclude that since the NGCC capacity in the Rising Price Case is not stranded, less overall deployment of the same capacity type (e.g., the deployment path in the Capped Price Case) would similarly not be stranded.